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LET'S TALK STRATEGY.

Pioneer Natural Resources Company

PIONEER NATURAL RESOURCES

2004 Annual Report

2004 ACCOMPLISHMENTS

- REPORTED RECORD CASH FLOW FROM OPERATIONS OF $1.1 BILLION
- REPORTED NET INCOME OF $313 MILLION, OR $2.46 PER DILUTED SHARE
- INCREASED PRODUCTION 21% TO 183 MBOEPD, A NEW RECORD
- REPLACED 441% OF 2004 PRODUCTION WITH AVERAGE FINDING AND DEVELOPMENT COST OF $10.48 PER BOE
- DRILLED 423 WELLS WITH 88% SUCCESS
- REPURCHASED 2.8 MILLION SHARES
- REDUCED DEBT BY $364 MILLION, PRO FORMA FOR EVERGREEN MERGER
- SUCCESSFULLY INTEGRATED EVERGREEN OPERATIONS

RECENT DEVELOPMENTS

- ANNOUNCED $900-$950 MILLION CAPITAL BUDGET FOR 2005, SIGNIFICANTLY STEPPING UP THE PACE OF EXPLORATION AND DEVELOPMENT DRILLING
- ENHANCED FINANCIAL FLEXIBILITY BY CLOSING TWO VOLUMETRIC PRODUCTION PAYMENTS WITH PROCEEDS OF $593 MILLION
- APPROVED NEW $300 MILLION SHARE REPURCHASE PROGRAM

FORWARD-LOOKING STATEMENTS

Except for historical information contained herein, the statements in this document are forward-looking statements that are made pursuant to the Safe Harbor Provisions of the Private Securities Litigation Reform Act of 1995. Forward-looking statements and the business prospects of Pioneer Natural Resources Company are subject to a number of risks and uncertainties that may cause Pioneer's actual results in future periods to differ materially from the forward-looking statements. These risks and uncertainties are described on pages 3 and 11 through 14 of Pioneer's Form 10-K included with this report.

TIMOTHY L. DOVE
President and
Chief Operating Officer

SCOTT D. SHEFFIELD
Chairman and
Chief Executive Officer

We formed Pioneer in 1997 with a vision to grow the Company by building on our long-lived oil and gas fields in North America and reinvesting the strong, stable cash flow from these predictable fields to develop remaining reserves, expand our position through acquisitions, and build a successful exploration program.

WE ARE DELIVERING ON OUR VISION. WE HAVE EXPANDED OUR LONG-LIVED OIL AND GAS FOUNDATION THROUGH DEVELOPMENT AND ACQUISITIONS AND HAVE BUILT A SIGNIFICANT TRACK RECORD OF GLOBAL EXPLORATION SUCCESS AND PRODUCTION GROWTH.

Today, the enterprise value of Pioneer has grown to approximately $8 billion. We are delivering on our original vision. We have expanded our long-lived oil and gas foundation through development and acquisitions and have built a significant track record of global exploration success and production growth.

Our vision hasn't changed, but some of our strategies have. We have adapted our strategies to take advantage of an ever-changing industry climate. We continue to benefit from the intrinsic value of our foundation assets, and we have built a portfolio of new investment opportunities around the world that offer attractive returns.

We ended 2004 setting a new Company record for daily production, and we replaced 441 percent of our annual production – adding 303 million oil-equivalent barrels through our exploration and acquisition activities.

We completed a merger with Evergreen Resources through which we acquired a significant position in the Rocky Mountains of southern Colorado. This new core area expanded our long-lived foundation – bringing opportunity for several years of production growth through low-risk development.

We achieved these results while generating significant cash flow in excess of our capital budget. Pro forma for the merger, we reduced debt $364 million, and we repurchased over 2.8 million shares of our common stock.

Like others in the industry, we have benefited from steadily rising prices for both oil and gas. The fundamentals for continued strength in both commodities are positive, and when considered in light of inflation and the relative prices we pay as consumers for other goods and services, energy prices seem more reasonable.

Outside the U.S., the impact of higher oil prices has been lessened by the relative weakness of the U.S. dollar. As world economies continue to grow, demand for energy continues to expand.

Supply is not a "given," as has been assumed by many in the past. Sources of natural gas to supply the growing demand in North America are becoming more and more difficult to identify. The world's remaining untapped oil reserves are primarily in areas challenged by harsh or volatile environments.

Have we entered a new era for energy prices? Many fundamental indicators point in that direction, and with the impact of world events that threaten supply, volatility has increased substantially. How high can prices go before worldwide demand declines significantly? That is a key question that has yet to be answered.

Higher oil and gas prices are significantly increasing the amount of available cash in our industry. These higher prices have spawned greater levels of activity – and as a result, we are seeing moderate cost increases across the industry. Nonetheless, net margins are up significantly. The ultimate beneficiaries will be the companies that invest this excess cash wisely and operate most efficiently.

When we have the opportunity to meet with our shareholders, the conversation is usually centered on our strategy – how we plan to accomplish our goals and meet the challenges faced by our industry.

As a result, we decided to dedicate this year's annual report to answering the most common questions that have been posed by fellow shareholders with whom we have had the honor to meet over the past year.

STRATEGY

How does your vision differ from other E&P companies?

SCOTT: All E&P companies have a vision of reinvesting cash flow to increase their proved reserves and production. Strategies may differ, but growth per share is the key objective.

One important difference in our vision has to do with the type of assets on which we have built our foundation. We have emphasized building a long-lived foundation to anchor the rest of our activities. The stability of production from these assets means we can be more patient. In other words, we don't fight as steep a production decline curve as our shorter-lived peers.

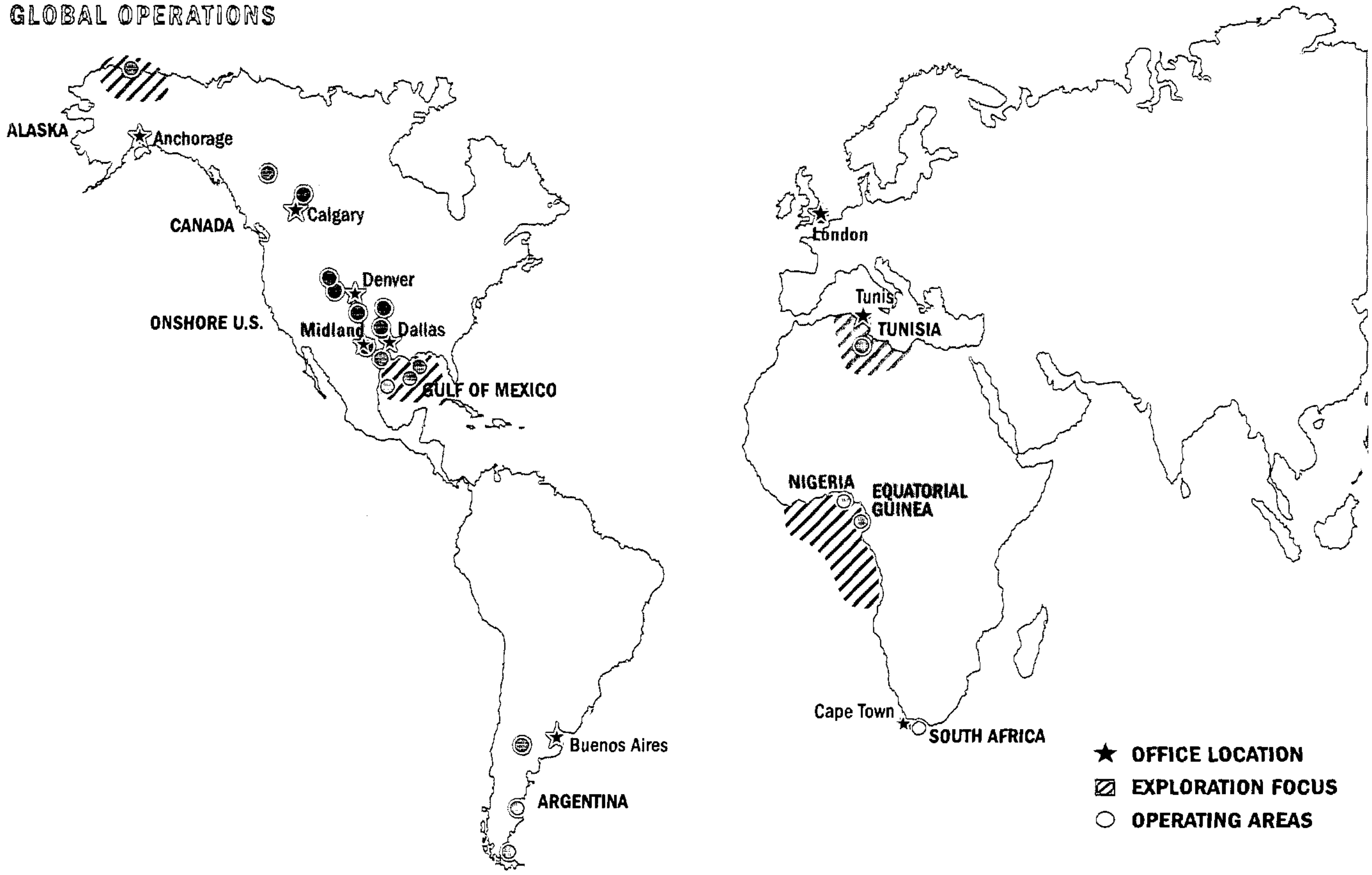
We have built these foundation assets through a long history of acquisitions and exploitation – going all the way back to the 1980s and the concurrent strategies upon which our founding companies were built. This long-lived foundation provides a greater level of free cash flow per share than that of other companies in our peer group. More free cash flow means more to invest for growth, or to return to our fellow shareholders.

As our U.S. assets became more mature, I realized that we needed to build our expertise in exploration, and that we eventually needed to broaden our reach to include more international opportunities. We began that process with the formation of Pioneer in 1997 – and relative to the size of the Company, we have had one of the highest-impact exploration programs in our peer group.

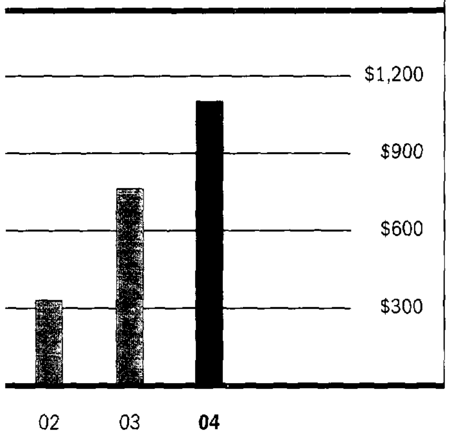
Based on a number of positive factors, including our exploration success and stable foundation assets, we have established a level of cash flow that allows us to be more proactive in seeking attractive acquisitions to expand our core areas. We have also gained expertise in developing large-scale, technically demanding projects, and we are evaluating opportunities to leverage this expertise by developing discoveries in our focus areas that – under prior economic assumptions – were never commercialized.

TIM: The merger we completed with Evergreen during 2004 supports our commitment to continue building on our long-lived foundation. Through this merger, we gained a key position in the Raton field, a premier U.S. coalbed methane project, with an estimated reserve life of over 30 years and considerable development upside. We see significant potential to leverage this coalbed methane expertise into

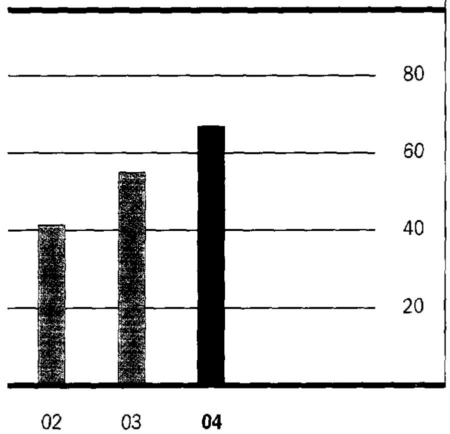
GLOBAL OPERATIONS



CASH FLOW FROM OPERATIONS
(MILLIONS)



ANNUAL PRODUCTION
(MILLION BARRELS OIL EQUIVALENT)



other "unconventional" resource opportunities, particularly in North America and potentially around the world.

While we have directed the majority of the past 5 years' capital budgets to developing our exploration successes, we have also been able to close about $500 million of acquisitions, which strengthened our core area positions. Acquisitions have comprised a significant component of our heritage, and while high commodity prices have led to a very competitive market for acquisitions, we will continue to pursue this avenue for growth when the economics are attractive.

With our deepwater Gulf of Mexico and South Africa projects, we gained significant expertise in large-scale offshore development – and we believe we can leverage this expertise into opportunities to evaluate and potentially develop discoveries that have been made by major oil and gas companies in the past but left undeveloped.

Our oil development and potential gas development in South Africa are salient examples of fields that were established by prior drilling. We entered South Africa and drilled additional exploratory wells to further define the resource potential, leading to a successful oil development and current negotiations to commercialize our South Africa gas discoveries.

Another good example is our Ooguruk project in Alaska. Again, this is an area that had been subject to prior drilling that indicated a significant resource presence. We drilled additional wells at Ooguruk, and we are now working to commercialize the field.

While this approach reduces the geologic risk, the commercialization risk still remains. Due to the complex nature of projects such as Ooguruk, we must have a "pipeline" of them ready to go – because we recognize that like pure exploration, some of these commercialization projects will meet our economic hurdles, but some will not.

Our first priority is to make sure we are being good stewards of capital.

What key strategies will you employ to fulfill your vision and differentiate your performance?

SCOTT: Our overarching strategy is to deliver net asset value accretion and enhanced shareholder value. To achieve this, we will utilize our 5 long-lived legacy assets in the U.S. (Spraberry, Raton, West Panhandle, Hugoton and Pawnee) to anchor production and cash flow.

These assets, which make up 79 percent of our proved reserves, have low maintenance capital requirements, and a reserve-to-production ratio of over 25 years.

We plan to leverage our expertise in complex development projects on the ones we are currently working to commercialize as well as on other undeveloped fields that we gain access to in our areas of focus.

We will also continue to pursue high-impact exploration opportunities that will provide good returns and production growth, both on an "absolute" and a per-share basis.

Our financial position has never been stronger, and we will strive to maintain the flexibility this strength provides to ensure that we can take advantage of the attractive opportunities that present themselves in the future.

TIM: We strive to be experts with the basics – to be excellent in the day-in, day-out "blocking and tackling." But we also believe it is important to have the optionality that a significant discovery could bring to the table. Many of our peers are focused on either one or the other.

We believe a combination of low-risk development and high-impact exploration provides shareholders with the steady benefit of high-return development in our core assets, and the added opportunity for large new field discoveries that can materially impact net asset value and growth potential.

And we have the right talent to tackle high-impact exploration. Before we entered the deepwater Gulf of Mexico, we hired an outstanding team of explorationists from the major oil companies. These professionals brought with them global expertise, which we are leveraging around the world, especially in deepwater offshore West Africa.

Why is a long-lived foundation so important?

SCOTT: Generally, production from any oil or gas well reaches peak levels early in the life of the well, when field volumes and pressures are at their highest. So all producing companies, like Pioneer, continually fight production declines on existing wells.

Production from wells in longer-lived fields – like the 5 long-lived fields we have onshore U.S. – declines more slowly, and provides a more stable foundation. With slower production declines and ample opportunity for additional development drilling, the capital investment required to maintain production from these fields is significantly less than the annual cash flow these fields generate.

With greater excess cash flow, we can explore, develop exploration successes, acquire assets, retire debt, pay a dividend, and repurchase outstanding equity – all directed at achieving better per-share value growth for our fellow shareholders.

TIM: The natural decline rate for our 5 long-lived onshore U.S. fields – before additional capital investment – is estimated to be approximately 8 percent per year. To offset this decline and maintain production, we need to invest about $250 million to $300 million per year.

Based on current oil and gas futures pricing, we expect cash flow from these fields to exceed $800 million in 2005 – providing about $500 million of excess cash flow for growth and other forms of shareholder returns.

In your merger with Evergreen, you acquired a new core position in the Raton Basin in Colorado's Rocky Mountains, surprising the market. What motivated your decision to complete this acquisition?

SCOTT: We have had considerable exploration success, and we've redirected the cash flow from our onshore base to develop that success.

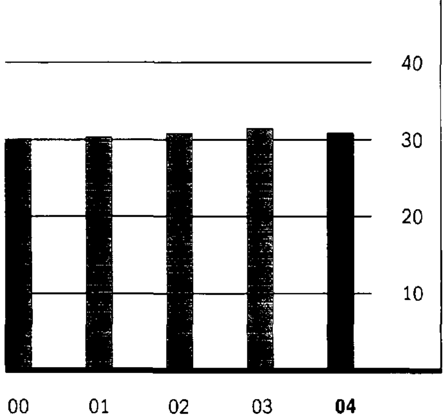
The merger offered us the opportunity to rebalance our asset portfolio and strengthen our long-lived onshore foundation to support a larger company. The Evergreen assets add a fifth core field to our North American foundation – with the potential to double production in the next 5 to 6 years by accelerating a proven development program that is supported by a tremendous track record.

This long-lived field will continue to produce gas for the next 30 to 40 years, so we view the transaction as a long-term positive for net asset value per share, and expect accretion on other financial measures, including earnings and cash flow per share. Seldom is a company able to acquire a legacy North American field such as Raton. So we have no doubt that the Evergreen merger represented a substantial opportunity for Pioneer shareholders.

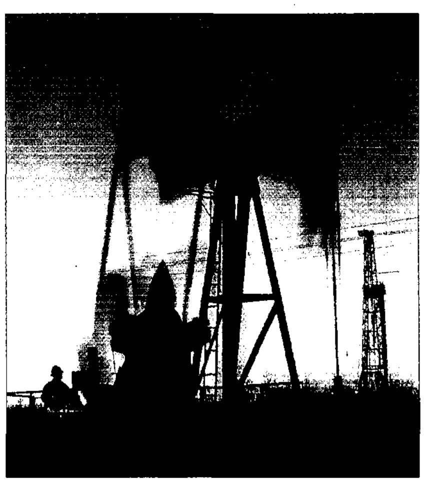
TIM: With at least 2,000 potential locations, we have room to grow production from these new assets for several years to come. We plan to drill approximately 300 coalbed methane wells in the Raton Basin during 2005, and we have ensured that we have the people and other resources in place to make that happen. The economics on the drilling of these wells are as good as any we have in the Company. In essence, we have added a growing annuity to the base that also significantly "de-risks" the overall portfolio.

Beyond the Raton field – which was the primary driver for the merger – we are beginning to get a clearer picture of the upside potential in the Piceance and Uinta Basins. We are also looking forward to the drilling we have planned in Canada this summer, targeting the Horseshoe Canyon coalbed methane play, where we have

U.S. ONSHORE FOUNDATION ASSETS ANNUAL PRODUCTION*
(MILLION BARRELS OIL EQUIVALENT)



* Pro forma for Evergreen merger



PRODUCTION FROM LONGER-LIVED FIELDS – LIKE THE 5 LONG-LIVED FIELDS WE HAVE ONSHORE U.S. – DECLINES MORE SLOWLY AND PROVIDES A MORE STABLE FOUNDATION.

acreage that is on trend with successful wells already drilled in the area.

Your strategies and vision are unique. What else differentiates Pioneer from your peers?

SCOTT: Beyond creating the best foundation and setting the right course, we rely on the talented and enthusiastic men and women who have chosen to be a part of the Pioneer team. I firmly believe that our people will make the difference between "average" performance and "outstanding" performance. We take pride in our unique Pioneer culture – stressing authentic, direct and open communication.

We reward innovation and empower our people to make a difference. Our employees accept individual responsibility for the common good – recognizing that our primary responsibility is for the health and safety of our people, our communities and the environment. Managing in a way that first considers environmental, health and safety issues is part of who we are. It defines our character and our culture.

And we recognize our responsibility to the communities in which we operate. We endeavor to be good neighbors and work with our communities to establish relationships that allow us to thrive together.

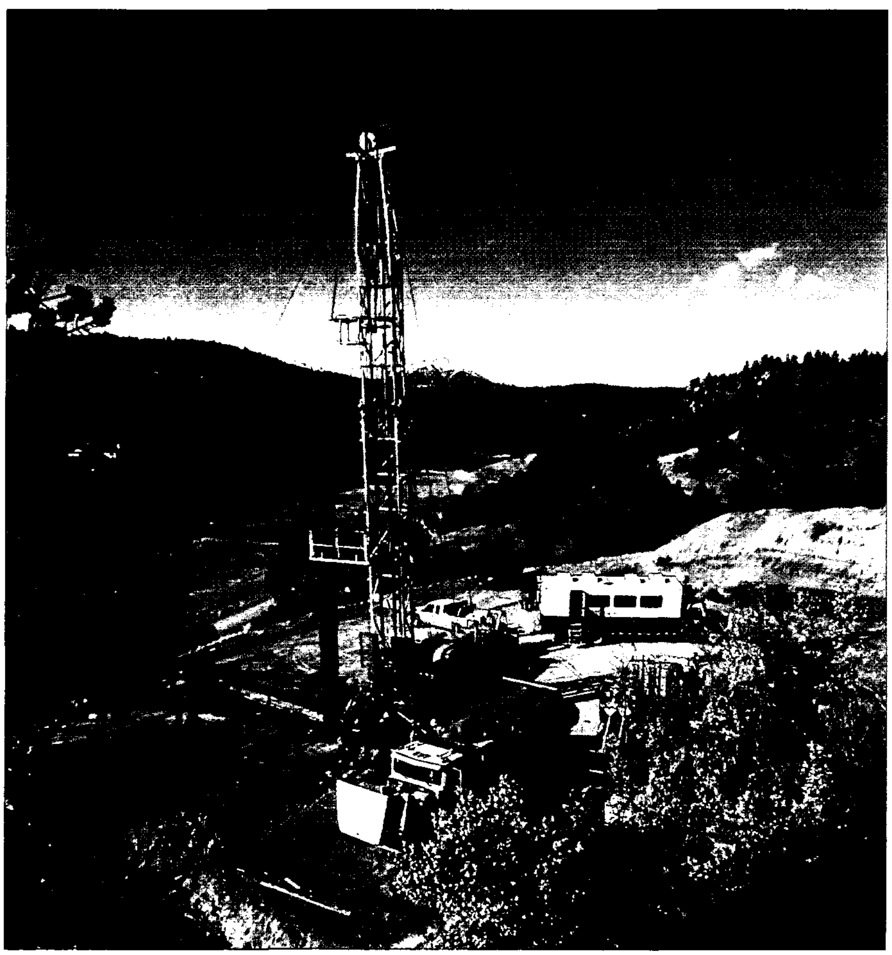
Sure – we push hard to succeed. But we refuse to compromise our integrity. All of our employees are eligible to participate in our employee stock-ownership plan based on the achievement of individual and Company performance goals – thereby assuring that all of our employees' interests are aligned with the interests of our fellow shareholders.

TIM: We have focused on establishing appropriate processes for accessing opportunities and evaluating performance. Fulfilling our vision requires that we constantly challenge ourselves and our assumptions. Peer reviews, post audits and our look-back analyses are key strengths. These all lead to better capital allocation decisions and improve our chances for exploration success.

SCOTT: We also take pride in the strong external relationships we have built, and we strive to be a "partner-of-choice." We have built our reputation on offering the varied expertise of a much larger company while maintaining the agility of an independent. And we are gaining broader recognition for this unique combination of skills and attitude.

Our recent entry into deepwater offshore Nigeria exemplifies this broader industry recognition. As we have built our international and exploration teams, we have intentionally hired engineers and geoscientists with broad global experience gained while working for the majors.

From our 1997 entry into South Africa – all the way up to our targeted



SELDOM IS A COMPANY ABLE TO ACQUIRE A LEGACY NORTH AMERICAN FIELD SUCH AS RATON. THIS LONG-LIVED FIELD WILL CONTINUE TO PRODUCE GAS FOR THE NEXT 30 TO 40 YEARS.

WE STRIVE TO BE A "PARTNER-OF-CHOICE." WE HAVE BUILT OUR REPUTATION ON OFFERING THE VARIED EXPERTISE OF A MUCH LARGER COMPANY WHILE MAINTAINING THE AGILITY OF AN INDEPENDENT.

North Africa position and our most recent focus on offshore West Africa – our broad expertise has allowed us to make a difference.

Our early success in the deepwater Gulf of Mexico opened doors to partner with a number of experienced producers. And as one of the first independents to operate in Alaska, we have been able to establish great rapport with both the large North Slope operators and the Alaska state government.

TIM: While many of our engineers and geoscientists were trained in positions with the majors, they are here because they prefer to approach problem-solving with the entrepreneurial attitude of an independent. Our people are experts in the tools required to successfully explore. And they have experience developing fields which require significant and sometimes-challenging infrastructure – and then operating those fields efficiently.

Provide them with the right tools. Place them in an environment where smart, motivated people are empowered and challenged, and decisions are timely. And you have the key to Pioneer's success. These are the traits that host governments and national oil companies look for when choosing partners for their most important projects.

More near-term, what are Pioneer's key critical success factors?

SCOTT: Prudent capital allocation is always important. But in times of prosperity when cash flow is abundant, it becomes even more critical. Still, the results of most of today's investments will not be evident for several years. So in the near term, we will be judged on what is visible: that is, on our ability to execute, rather than on strategic decisions.

We have an active exploration program planned for 2005 and 2006, and success with that program will provide clarity as to our future production growth. Over the last 18 months, most of our geoscientists' efforts and exploration investments have been directed to establish and bring to maturity the opportunities we will now test with the drillbit.

We must also deliver on the expectations we have laid out for our newly acquired Rocky Mountain assets.

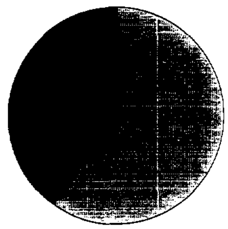
In Argentina, I believe we will continue to see growth in demand for gas and increasing gas prices. Visibility on the improving value of our Argentina assets could be a catalyst to increase the market's valuation of Pioneer stock.

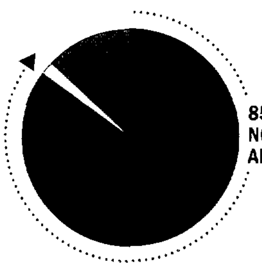
As we've already discussed, we have several discoveries that we are working to commercialize that are important to production growth in 2007 and 2008 – the most important being the Oooguruk oil discovery in Alaska and our gas project offshore South Africa.

Approval of these projects would also provide more clarity on future production growth.

TIM: With excess cash flow, our commitment to return capital to shareholders becomes increasingly important. We reestablished the dividend and our share repurchase program in 2004, and we view the continuation of these vehicles as direct indicators of our success. We will also strive to establish realistic stock market expectations, especially as they relate to our exploration expense exposure.

PROVED OIL AND GAS RESERVES
1.02 BILLION BARRELS OIL EQUIVALENT*
$9.1 BILLION VALUE**





*Proved reserves as of 12/31/04, 88% of reserves audited by Netherland, Sewell & Associates, Inc.
**Valuation based on year-end NYMEX oil and gas prices of $43.33 per barrel and $6.19 per MCF utilizing a 10% present value discount rate.

IN OUR INDUSTRY, VALUE IS DRIVEN BY PROVED OIL AND GAS RESERVES AND THE POTENTIAL TO INCREASE PROVED RESERVES.

For an explorer, we utilize the most conservative accounting convention, under which we immediately expense the cost of unsuccessful wells and seismic expenditures – rather than capitalizing these costs, as a majority of our exploration-focused peer companies do. As a "successful efforts" company with an active exploration program, forecasting exploration expense is challenging. We recognize that reliable earnings guidance is paramount to maintaining credibility with the investment community.

INTRINSIC VALUE

Your vision and strategy are directed at increasing net asset value. What are the key components of Pioneer's value?

SCOTT: In our industry, value is driven by oil and gas proved reserves – and the potential to increase proved reserves.

As of December 31, 2004, we had total proved oil-equivalent reserves of just over 1 billion barrels – valued at over $9 billion under the SEC-prescribed valuation method, using year-end oil and gas prices and a 10 percent present value discount rate.

To ensure confidence in our reserve estimates, we ask Netherland, Sewell & Associates, a leading U.S. reserve-engineering firm, to audit our proved reserves and their value for our major fields. These fields represented 88 percent of our total reserves at year-end 2004.

Through their audit, Netherland, Sewell & Associates compare their estimates to our internal reservoir engineering estimates to make sure our estimated reserves – and the value of those reserves – are reasonable. Confidence in reserve estimates is critical, and we believe that the proved reserves for the most significant fields of all publicly traded companies should be audited by independent outside experts, just as their financial statements are.

The value related to our potential to increase proved reserves is more difficult to quantify. We have several discoveries that we have not yet booked as "proved reserves" because we are still evaluating the commercial viability to develop them.

Value created by our future exploration program will, of course, depend on its success. But to date, we have added approximately $1.2 billion of value through exploration, and we expect to add to this number in 2005 and beyond.

We have an extensive lineup of wells to drill over the next few years in each of our 4 exploration focus areas: Gulf of Mexico, Alaska, West Africa and North Africa.

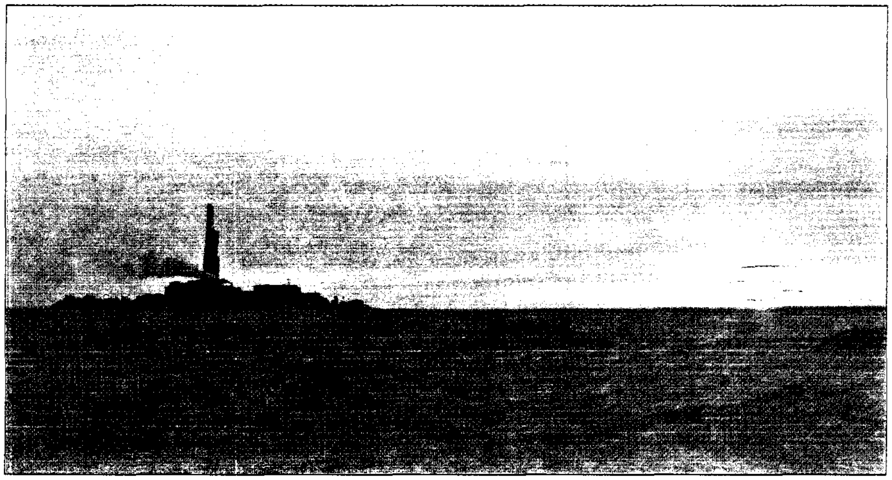
TIM: We also expect to add value by leveraging our expertise in developing "unconventional" resources, and we have acreage positions in the Piceance and Uinta Basins in the Rocky Mountains and the Horseshoe Canyon play in Canada that have significant potential.

In Argentina, the value of our assets is poised to grow from continued increases in the price of

KEY EXPLORATION FOCUS AREAS

- GULF OF MEXICO
- ALASKA
- WEST AFRICA
- NORTH AFRICA

VALUE CREATED BY OUR FUTURE EXPLORATION PROGRAM WILL DEPEND ON ITS SUCCESS. WE HAVE ADDED APPROXIMATELY $1.2 BILLION OF VALUE THROUGH EXPLORATION, AND WE EXPECT TO ADD TO THIS NUMBER IN 2005 AND BEYOND.



gas, as well as from potential new field discoveries resulting from our Argentine drilling program.

In pricing Pioneer stock, the market seems to be significantly discounting the value of your reserves. What is the market missing?

SCOTT: Historically, the equity markets have failed to appropriately value long-lived reserves. Rather than forecasting oil and gas prices, annual production, lifting costs and the appropriate discount rate over the remaining 30 to 40-year lives of these fields, many analysts generally use a multiple of current annual cash flow as a proxy for value.

Analysts then apply the same cash flow multiple to long-lived reserves and shorter-lived reserves, without sufficient consideration for the differences in sustainability. Running a company with a high percentage of longer-lived reserves – reserves that exhibit shallower production declines and require lower amounts of maintenance capital – is obviously preferable.

But it has always been a challenge – and will likely always be a challenge – to persuade the market to value those reserves appropriately. I am encouraged by recent indications that some investors and analysts have begun to recognize the market's inefficiency in this regard.

We also receive little to no value from the market regarding our exploration program, despite having built a solid exploratory track record over the last 5 to 6 years. Considering the market's obsession with near-term results, the longer-term nature and greater relative risk of oil and gas exploration can create considerable tension that weighs on our stock price.

Our "successful efforts" accounting convention – as compared to the "full cost" convention used by most of our exploration-focused peer companies – accelerates the recognition of our exploration and seismic costs and puts pressure on near-term returns. Over the long-term, by immediately expensing these costs, we reduce depletion charges and post higher returns.

TIM: Although our deepwater success is an important contributor to our returns, growth and cash flow, these deepwater fields are shorter-lived than our onshore production and have become a basis for concerns about production declines. While we have openly acknowledged and discussed the declines – and laid out our plan for offsetting them – I believe those concerns are definitely having an unjustified impact on the market's valuation of our stock.

Clearly, the value of our reserves in Argentina is also being heavily discounted as a result of the devaluation of the Argentine peso in early 2002. The market has lagged in its recognition of the burgeoning opportunities related to the strong growth in gas demand in Argentina, and the resulting significant upward trends we have seen in gas prices there. We think we are at a time of inflection in Argentina, with the potential for significant accretion in the value of our Argentine gas reserves.

With long-lived reserves, monetization through normal production channels requires patience. Is there anything you can do to tap into that value today?

SCOTT: Over the last several years, we have considered a number of monetization tools. And in January 2005, we announced that we sold 2 percent of total Company reserves – or 20.5 million oil-equivalent barrels – by means of two volumetric production payments, or VPPs. Basically, we sold a limited-term overriding royalty interest in two of our long-lived legacy assets for $593 million.

With oil and gas prices at all-time highs and interest rates at 30-year lows, we received a portion of the next 5 to 7 years of cash flow from our Hugoton and Spraberry fields today.

Use of the VPP is a particularly effective monetization strategy for Pioneer's longer-lived asset base, because it allows us to keep the oil and gas reserves and production stream beyond the limited term of the overriding royalty, while continuing to benefit from the upside potential of future development drilling.

On an oil-equivalent basis, we received about $29 per barrel in proceeds which reflects the first 5 to 7 years of production volumes and excludes future production costs and income taxes associated with the sale. Looking at it another way: In exchange for 2 percent of our reserves, we realized proceeds equal to approximately 8 percent of the enterprise value being ascribed to Pioneer by the markets at the time of the transaction.

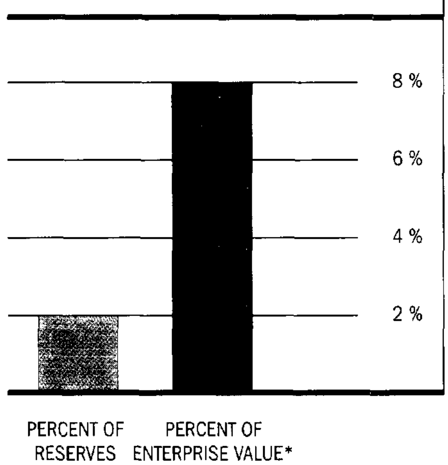
Accelerating the monetization of these reserves allowed us to complete our targeted debt-reduction program, and provided us the flexibility to capture the arbitrage opportunity presented by the equity market's failure to appropriately value companies with longer-lived reserves.

During 2004, we took advantage of this arbitrage opportunity and repurchased $92 million of our common shares. And the Board of Directors has approved a new $300 million share repurchase program under which we have been actively buying shares. The VPPs were a significant transaction, improving the financial flexibility of the Company and highlighting the true value of our long-lived assets.

TIM: We have seen a "decoupling" of commodity prices and interest rates over the last couple of years. Since – in general – they have historically moved in tandem, the fact that they have recently moved in opposite directions has created a unique opportunity.

The confluence of high commodity prices and low interest rates significantly increases the value of the capital that resides in our long-lived reserve base. With the VPP, this long-lived base becomes an even more advantageous asset that we can tap into if and when we identify a clear opportunity for high-return reinvestment.

VOLUMETRIC PRODUCTION PAYMENTS (VPP)



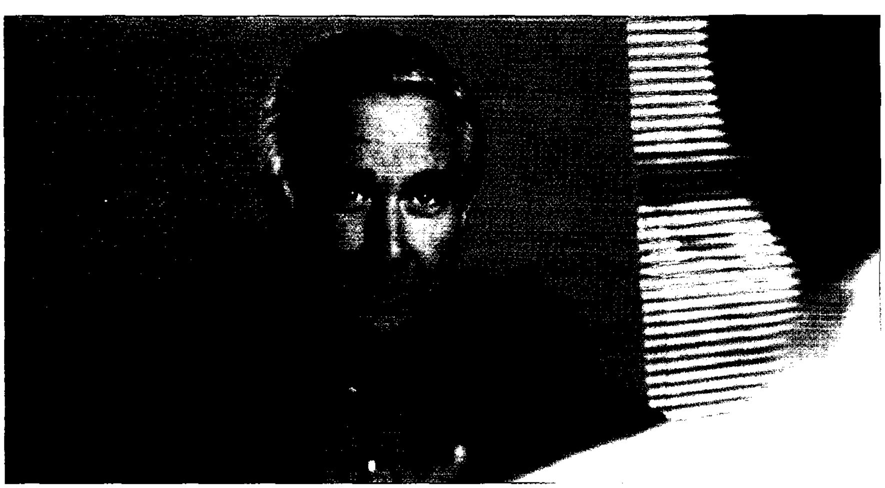
*VPP proceeds exclude future production costs and income taxes associated with the sale.

THROUGH THE VPP TRANSACTIONS, WE EXCHANGED 2 PERCENT OF OUR RESERVES FOR REALIZED PROCEEDS EQUAL TO APPROXIMATELY 8 PERCENT OF OUR ENTERPRISE VALUE.

How would you characterize Pioneer's current financial position?

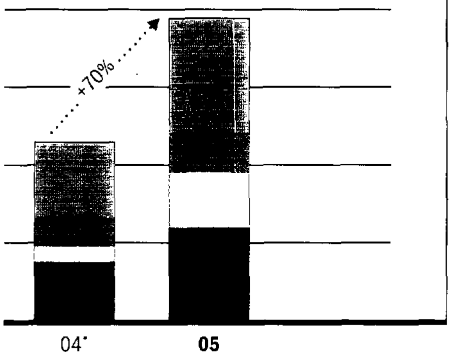
SCOTT: We are at the strongest point in our 7-year history. We have reduced our debt-to-book-capital ratio to 39 percent. And our intent is to reduce it further – to below 35 percent – by the end of the year.

We are committed to achieving financial metrics that support moving our "investment grade" ratings even higher. And we believe a strong balance sheet is critical, especially since our strategy involves taking measured risks in exploration and



THE CONFLUENCE OF HIGH COMMODITY PRICES AND LOW INTEREST RATES SIGNIFICANTLY INCREASES THE VALUE OF THE CAPITAL THAT RESIDES IN OUR LONG-LIVED RESERVE BASE.

DEVELOPMENT WELLS DRILLED/ PLANNED IN KEY AREAS



* Pro forma for Evergreen merger

in international arenas that, when successful, require both time and the investment of significant capital before generating cash flow.

TIM: The key for Pioneer – and, for that matter, the key for the industry – is to have a balance sheet that can weather the upturns and downturns in commodity prices, given the fact that we can't predict when those will occur. We operate in a very capital-intensive business, and when we have success and identify large development projects that we need to fund, we want to make sure we have a balance sheet that will allow us to do so.

As we mentioned earlier, we also have the flexibility to further extract capital from our long-lived reserves in order to fund opportunities that offer higher growth potential, when presented. The bottom line: Today, we enjoy a tremendous level of financial flexibility.

OPPORTUNITY

Considering the significant amount of cash flow you expect based upon the factors we've touched on, would you discuss the projects that are available to Pioneer for reinvesting this cash?

SCOTT: We are fortunate to have a large inventory of development locations, and we are accelerating development in all of our key producing areas – especially in the Raton Basin and in the Spraberry field in the U.S., as well as in Canada. In Argentina, improving economics are also providing new opportunities for development drilling.

In total, we are increasing the number of development wells drilled in 2005 by approximately 70 percent. We also plan to increase our level of step-out exploration in lower-risk plays in Argentina, Tunisia and South Texas.

In addition, we have discussed two commercialization projects – one in Alaska and one in South Africa – that we hope to be developing by the end of this year, assuming project economics meet our established hurdles.

Specifically, on Alaska's North Slope, we are evaluating the development of our Oooguruk discovery. We are moving forward with the permitting process while completing our engineering studies. And we expect to have sufficient information to make a decision later this year.

In South Africa, we are negotiating with our partner, PetroSA, on plans to develop gas reserves for sale to a synthetic gasoline plant onshore. We are also carefully evaluating opportunities to develop existing discoveries in the deepwater Gulf of Mexico and in Tunisia.

From this large project inventory and our impact-oriented exploration program, we expect annual production growth on a per-share basis.

TIM: For the last 2 years, we invested the bulk of our exploration budgets in building and maturing our portfolio, and will test several new prospects in the next 2 years. During 2005, we plan to drill approximately 20 higher-impact exploration wells with total unrisked potential of over 500 million net oil-equivalent barrels, equal to half of Pioneer's current proved reserves.

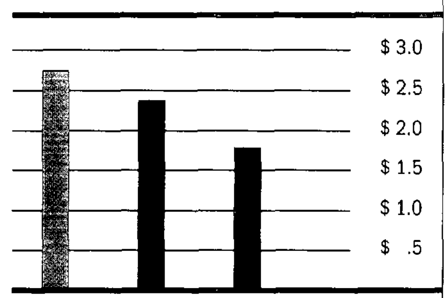
Success from this program could generate several new development opportunities. With today's strong commodity prices, we also believe we can leverage our Raton Basin coalbed methane expertise in other "unconventional" natural gas resources. In this regard, we have several studies underway.

We also continue to work very diligently to identify potential "bolt-on" acquisitions in our core areas. But at the same time, we realize that achieving success in acquisitions will be difficult, given today's high commodity prices and our commitment to strictly adhere to our minimum return hurdles.

Your plans for 2005 include significant exploration investments. Can you share with us your views about the exploration opportunities that remain around the world today?

SCOTT: Let me first emphasize that Pioneer remains highly focused on

LONG-TERM DEBT (BILLIONS)



12/31/03*	12/31/04	12/31/04 VPP**	
50%	46%	39%	DEBT/ BOOK
$2.61	$2.33	$1.79	DEBT/ BOE

* Pro forma for Evergreen merger
** Pro forma for VPP transaction in January 2005

FOR THE LAST 2 YEARS, WE INVESTED THE BULK OF OUR EXPLORATION BUDGETS IN BUILDING AND MATURING OUR PORTFOLIO AND WILL TEST SEVERAL NEW PROSPECTS IN THE NEXT 2 YEARS.

exploration. We believe exploration is one of our key competencies. But to properly manage the risk associated with exploration, we believe in a "portfolio" approach. In other words, we prefer to have multiple areas of focus, as well as multiple play types.

We generally limit our participating interest in individual prospects to between 20 percent and 40 percent. This effectively increases the number of prospects we test and spreads the risk across a larger number of wells.

In North America, few attractive opportunities remain, as evidenced by the relatively low level of exploration activity. At Pioneer, we were fortunate to secure positions in the deepwater Gulf of Mexico during the late 1990s. We drilled several successful wells on prospects that, based on seismic interpretation, exhibited direct hydrocarbon indicators. Prospects of this type that remained undrilled were generally smaller in size, but lower-risk.

Most of these prospects have now been drilled, and exploration in the deepwater Gulf has shifted to deeper formations, generally beneath hard-to-image salt bodies. These new plays are higher-risk, but offer potential for larger discoveries.

We have several prospects targeting subsalt plays in deepwater, and we plan to test a few of them this year. A number of leases held by other companies – mostly major oil companies – are expiring and should become available in 2006 and 2007. As we evaluate new plays, we plan to build on our deepwater acreage position.

To diversify our North American exploration program, in 2002 we entered the North Slope of Alaska. We have built a sizable and diverse inventory of projects in a relatively short time.

In Alaska, the majors have discovered and developed several huge fields. But with a historical outlook of $20 oil prices, the majors had limited their capital investments – leaving several key discoveries undeveloped. We recognized this as an opportunity, and we are now the third-largest acreage holder on Alaska's North Slope. Our plans are to drill several wells and shoot 3-D seismic this year.

Significant opportunities continue to exist for companies like Pioneer – who take an independent's approach to cost structure and work to change the prevailing mentality of high-cost development. For example, we are partnering with a Canadian drilling company and a native Alaskan drilling contractor to provide a more efficient rig to drill many of our North Slope prospects.

Also, as the risk profile for the deepwater Gulf of Mexico shifted in recent years, we began looking for international opportunities that we felt would still offer prospects with direct hydrocarbon indicators in order to reduce geologic risk. We realized we would be taking on greater political risk and longer lead times as a tradeoff.

West Africa soon became our primary area of focus. We plan to test several West Africa prospects this year and next, and complete the technical work on several others for future drilling.

We also targeted North Africa and have had success in the Ghadames Basin in Tunisia. In addition, we are evaluating several opportunities in neighboring Algeria, as well as in Libya where U.S. sanctions prohibiting companies from doing

HAVING A PORTFOLIO OF PROSPECTS AND PLAY TYPES IS CRITICAL.

business were recently lifted.

We will continue to look for opportunities to apply our solid technical understanding of the geology of the various North Africa basins – as well as our established commercial foothold in the region – to build on our strong North African relationships.

TIM: Having a portfolio of prospects and play types is critical – as is participating in enough wells to give us a good shot at delivering strong results, based on the statistical risk versus reward of the portfolio. After all, the successful wells in the program have to be strong enough to carry the wells that prove unsuccessful.

We have also built our portfolio with a variety of risk/return profiles. As an example, we have extensive Alaska acreage holdings in the large, essentially undrilled areas of the National Petroleum Reserve. As Scott just mentioned, we are also evaluating the commercialization of discoveries made by prior acreage holders – under different economic conditions – on other North Slope acreage that we now hold.

As oil and gas prices rise, service costs are also rising. What steps are you taking to control costs?

SCOTT: Cost control is a priority – and we have challenged every Pioneer employee to be innovative in controlling costs.

We have taken ownership of some of the drilling rigs and service equipment we use. In certain cases, we have entered into partnerships with other companies to build more efficient rigs. We are using the latest technology in order to reduce the need for services.

In the Spraberry field, we are using new bit technology to reduce the number of days needed to drill a well. Drilling now takes 6 to 7 days, which is down from a previous average of 10 to 12 days.

We continue to install telemetry in all of our key U.S. fields. Telemetry allows us to remotely monitor well performance – maximizing production and reducing service costs by more effectively utilizing our field personnel.

TIM: The oil and gas industry is facing increasing costs – and this, in turn, is putting pressure on the economics of some projects. By owning our own equipment – and controlling the gathering and processing of essentially all of our gas – we have greater control over our own destiny, which allows us to enhance our margins.

In the extreme case – and as evidence of our capital discipline – we have been proactive in shutting down a drilling program or canceling a development project when costs have risen to the point of compromising returns. We have then proceeded to reallocate capital elsewhere.

You have been fairly aggressive in repurchasing your common shares outstanding. How do you compare share repurchases with your other investments?

SCOTT: As with all investment decisions, it revolves around returns. With our stock trading at what equates to an enterprise value of approximately $8 per equivalent barrel of oil – significantly below our assessment of our net asset value – share repurchases offer outstanding returns.

And they also increase net asset value per share, which is our key focus. As we have stated, in 2004 we invested $92 million in share repurchases, and in 2005 we have established a new $300 million stock repurchase program.

As we strive to maintain capital discipline in the face of rising costs, a factor critical to our success will be our ability to effectively balance our investments between absolute growth opportunities and share repurchases.

TIM: In light of current strong commodity prices – along with our excess cash flow and the benefits provided by the recent VPPs – we are an ardent believer in returning capital to shareholders.

It's great to have the best of both worlds, returning capital to shareholders while funding substantial drillbit growth from new projects.

RISKS TO STRATEGY

What are the biggest risks to your strategy?

SCOTT: As with any oil and gas producer, the prices we receive for the oil and gas we produce are products of macroeconomics that are beyond our control. The scarcity of remaining resources forces us to step outside the relatively secure political and economic environment of North America to find more oil and gas.

To help mitigate these risks, we strive to maintain a relatively balanced portfolio. Our reserves consist of approximately 60 percent gas and 40 percent oil. Our strong North America presence reduces our political risk.

We focus our exploration efforts on mature basins where the presence of hydrocarbons has been established – coupled with opportunities in less-mature basins where opportunities remain for discoveries of greater relative size. We balance our portfolio by targeting U.S.-governed opportunities in the Gulf of Mexico and Alaska, as well as opportunities in North and West Africa.

A great deal of analysis takes place before we make a decision to enter a foreign country. We want to ensure that the below-ground hydrocarbon opportunities are significant enough to justify the above-ground political and economic risks. This analysis includes an in-depth study of the political and economic environment, as well as significant personal interaction with government officials and representatives of companies that are already doing business in the country.

TIM: We have production in South Africa and Tunisia. Both are considered relatively low risk when compared to other African countries. We are considering the expansion of our position in North Africa to include either Libya or Algeria or both. These two countries represent somewhat higher risk than Tunisia, but they offer significant resource potential.

Our interests in Nigeria – where major oil companies have had successful operations for over 30 years – are limited to deepwater prospects that are over 100 miles offshore.

As a result of the devaluation of the Argentine peso in 2002, we experienced a setback in Argentina. But as we have stated, we've already seen significant recovery in both energy demand and the price we receive for gas in Argentina.

In terms of complying with all federal requirements for dealing with foreign entities, we take our responsibilities very seriously. In absolutely all of the Company's business dealings, we insist on the very strongest standards in both ethics and integrity.

How do you manage commodity price risk?

SCOTT: Our primary defense against commodity price risk is the use of conservative assumptions for future prices when we evaluate the economics of projects. Projects that do not meet our strict hurdle rates for return-on-investment using these conservative price assumptions are simply not pursued.

We also estimate the commodity prices required to break even on a project, considering a discount rate of 10 percent. We have utilized hedges to protect project economics, especially to lock in prices for the first 2 to 3 years. The two VPPs we discussed earlier also represent a means to lock in commodity prices, with the added benefit of collecting the revenue early, at historically low discount rates.

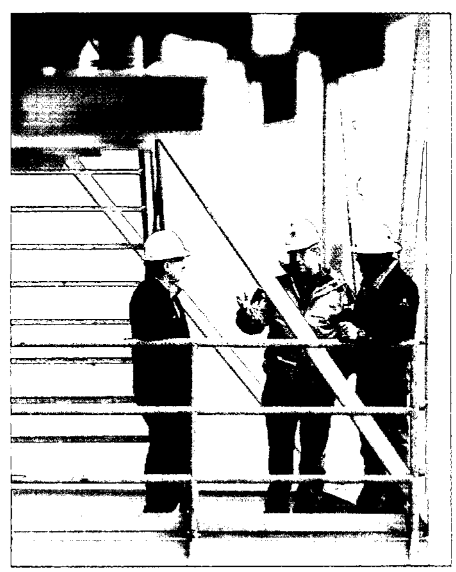
TIM: The hedging we have done in the past was focused on several key projects – such as Canyon Express and Falcon – that demanded significant upfront capital in a period of lower commodity prices.

Since then, we've significantly improved our balance sheet achieving "investment grade" status. And today's high commodity prices, coupled with production growth, have resulted in the Company generating significant excess cash flow above normal capital requirements. Accordingly, future hedging will be more heavily focused on opportunity-driven transactions, such as VPPs.

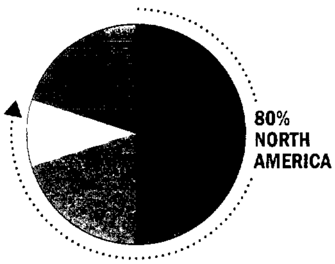
What keeps you awake at night?

SCOTT: I believe we are well into the early stages of a cycle of strong demand growth and high commodity prices – similar to the cycle that lasted from 1973 to 1981.

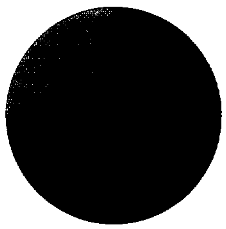
Current indications lead us to believe that this cycle could last another 4



2005 CAPEX BUDGET
$900-$950 MILLION



GULF OF MEXICO	25%
OTHER ONSHORE U.S.	25%
ROCKIES	20%
ALASKA	5%
CANADA	5%
ARGENTINA	15%
AFRICA	5%



LOW-RISK DEVELOPMENT	75%
HIGH-IMPACT EXPLORATION	25%

CAPITAL DISCIPLINE IS CRITICAL. WE MUST REMAIN VIGILANT IN ALLOCATING CAPITAL ONLY TO THE BEST OPPORTUNITIES.

years or maybe longer. But as we have seen in the past, the benefit of high excess cash flow is accompanied by many challenges. As prices rise, so do our costs.

The frenzied spending of the early '80s led to oversupply and poor returns. Capital discipline is tough to maintain considering the ever-present temptation to raise commodity price assumptions in order to justify project approvals. We must remain vigilant in allocating capital only to the best opportunities.

We must also balance development, exploration and acquisition investments – which grow the Company – with direct returns to shareholders in the form of dividends and share repurchases.

One other very important point: As we grow, we must focus much more attention on maintaining our unique culture – this takes actions, not just words, and management's commitment to stay in touch is critical. Communication becomes even more important to ensure that our people are recognized, our talent pool is protected, and that we move forward with a united vision and purpose.

What about the next 5 years?

SCOTT: Over the next 5 years, I want to be able to look back and realize that Pioneer has met its objectives of creating exceptional net asset value, while concurrently being one of the top-quartile stock price performers relative to our peer group.

We want to be known for having created value while also adding substantial production and reserves on a per-share basis through a combination of profitable exploration and development success, smart acquisitions, efficient operations and strategic share repurchases.

Absolute size is really not that important – but size-per-share does matter. We hope to grow as a result of our success. But at the same time, we believe there is a point at which size becomes more of a burden than a benefit.

Our culture is unique – and we plan to protect it. That means spending time to attract great people and providing an environment in which people flourish. In order to take Pioneer where we plan to go, we recognize that we will need both our special culture and strong personnel.

We plan to be recognized as a global company with one of the best exploration and development track records in the business – in both "conventional" and "unconventional" resources. And we expect to further strengthen our balance sheet in order to be ready for whatever price environment the future may hold.

TIM: We want to have an industry-leading track record in terms of health, safety and environmental standards, as well. We also want to be known for our high standards in terms of ethical business practices and integrity.

Most of all, we want our employees to look back after 5 years and – despite the many challenges – say they really enjoyed this time in their careers, and that they genuinely had fun working and succeeding in a very big way at Pioneer.

SCOTT: We take very seriously the confidence of both our fellow shareholders and our employees in our ability to lead the Company to new heights. If we are careful to focus steadily on our stated goals, we believe Pioneer has an opportunity to continue to gain momentum and be a significant influence in world energy – one of the most challenging but rewarding arenas in which to work and invest in the 21st century.

LET'S TALK NUMBERS.

PIONEER NATURAL RESOURCES

2004 10-K (as Amended)*

*10-K amended to change the date of the Annual Meeting of Stockholders to May 11, 2005.

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

FORM 10-K (with Amendments)

/ X / **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2004

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

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

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

Aggregate market value of the voting common equity held by non-affiliates of the Registrant computed by reference to the price at which the common equity was last sold as of the last business day of the Registrant's most recently completed second fiscal quarter	**$ 4,174,193,054**
Number of shares of Common Stock outstanding as of February 17, 2005	**143,669,263**

Documents Incorporated by Reference:

(1) Proxy Statement for Annual Meeting of Shareholders to be held May 11, 2005 - Referenced in Part III of this report.

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TABLE OF CONTENTS (CONT.)

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. 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" and "Item 1. Business - Risks Associated with Business Activities" for a description of various factors that could materially affect the ability of Pioneer Natural Resources Company to achieve the anticipated results described in the forward-looking statements.

Definitions of Oil and Gas Terms and Conventions Used Herein

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

- **"Bbl"** means a standard barrel containing 42 United States gallons.
- **"Bcf"** means one billion cubic feet.
- **"BOE"** means a barrel of oil equivalent and is a standard convention used to express oil and gas volumes on a comparable oil equivalent basis. Gas equivalents are determined under the relative energy content method by using the ratio of 6.0 Mcf of gas to 1.0 Bbl of oil or NGL.
- **"Btu"** means British thermal unit and is a measure of the amount of energy required to raise the temperature of one pound of water one degree Fahrenheit.
- **"GAAP"** means accounting principles that are generally accepted in the United States.
- **"LIBOR"** means London Interbank Offered Rate, which is a market rate of interest.
- **"MBbl"** means one thousand Bbls.
- **"MBOE"** means one thousand BOEs.
- **"MMBOE"** means one million BOEs.
- **"Mcf"** means one thousand cubic feet and is a measure of natural gas volume.
- **"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, Gabon, 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; Libreville, Gabon; Capetown, South Africa and Tunis, Tunisia. At December 31, 2004, the Company had 1,550 employees, 889 of whom were employed in field and plant operations.

Available Information

Pioneer files annual, quarterly and current reports, proxy statements and other documents with the SEC under the Securities Exchange Act of 1934. The public may read and copy any materials that Pioneer files with the SEC at the SEC's Public Reference Room at 450 Fifth Street, N.W., Washington, 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.pioneernrc.com) its Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and, if applicable, amendments to those reports filed or furnished pursuant to Section 13(a) of the Exchange Act as soon as reasonably practicable after it electronically files such material with, or furnishes it to, the SEC.

Evergreen Merger

On September 28, 2004, Pioneer completed its 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. At the merger date, Evergreen's proved reserves were 262.2 MMBOE. 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 was based in Denver, Colorado and was one of the leading developers of coal bed methane reserves in the United States. Evergreen's operations were principally focused on developing and expanding its coal bed methane 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 provide shareholders with superior investment returns through strategies that maximize Pioneer's long-term profitability and net asset value. The strategies employed to achieve this mission are predicated on maintaining financial flexibility and capital allocation discipline. Historically, these strategies have been anchored by the Company's long-lived Spraberry oil field and Hugoton and West Panhandle gas fields' reserves and production. Since the fourth quarter of 2004, the strategy is also enhanced by the newly acquired Raton gas field. Underlying these fields are approximately 75 percent of the Company's proved oil and gas reserves as of December 31, 2004. These fields have a remaining productive life in excess of 40 years. The stable base of oil and gas production from these fields, combined with the deepwater Gulf of Mexico Canyon Express, Falcon area and Devils Tower projects which began production in September 2002, March 2003 and May 2004, respectively, and the Sable oil discovery in

South Africa which began production in August 2003, should generate the operating cash flows to fund the Company's $900 million to $950 million capital budget for 2005 and allow the Company to further enhance its financial flexibility during 2005.

During 2004, the Company utilized capital from its long-lived Spraberry, Hugoton and West Panhandle fields and shorter-lived deepwater Gulf of Mexico projects to partially fund the merger with Evergreen and to selectively reinvest in assets that the Company believes will offer superior investment returns. Similarly, during 2005, the Company will continue 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 under terms that will complement the Company's exploration and development drilling activities; (iii) invest in the personnel and technology necessary to maximize the Company's explorationand 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 through superior 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 2004 and recent years. During 2004, the Company has also been affected by increasing costs, particularly the cost of steel and higher drilling and well servicing rig rates. World oil prices have increased in response to political unrest and supply disruptions in Iraq and Venezuela while North American gas prices have improved as supply and demand fundamentals have strengthened. Significant factors that will impact 2005 commodity prices include the final resolution of issues currently impacting Iraq 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 K 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 the years ended December 31, 2004, 2003 and 2002 from the Company's hedging activities and the Company's open hedge positions at December 31, 2004.

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, Gabon, South Africa and Tunisia. Combined, these assets create a portfolio of resources and opportunities that are well balanced among oil, NGLs and gas, and that are also well balanced between long-lived, dependable production and exploration and development opportunities. Additionally, the Company has a team of dedicated employees that represent the professional disciplines and sciences that will allow Pioneer to maximize the long-term profitability and net asset value inherent in its physical assets.

The Company provides administrative, financial and management support to United States and foreign subsidiaries that explore for, develop and produce oil, NGL and gas reserves. Production operations are principally located domestically in Texas, Kansas, Colorado, Louisiana 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, 2004, the Company's average daily production, on a BOE basis, increased as a result of (i) gas production beginning in January 2004 from the Company's Harrier gas field in the deepwater Gulf of Mexico, (ii) oil production beginning in May 2004 from the Company's Devils Tower oil field in the deepwater Gulf of Mexico, (iii) gas production beginning in June 2004 from the Company's Raptor and Tomahawk gas fields in the deepwater Gulf of Mexico, (iv) a full year of gas production from the Company's Falcon field in the deepwater Gulf of Mexico, (v) a full year of oil production from the Company's Adam field in Tunisia, (vi) a full year of oil production from the Company's Sable field offshore South Africa, (vii) increased production from Argentina and (viii) fourth quarter production from the properties added in the Evergreen merger. These increases more than offset normal production declines. During the year ended December 31, 2003, the Company's average daily oil, NGL and gas production increased as a result of (i) a full year of gas production from the Company's Canyon Express gas project in the deepwater Gulf of Mexico, (ii) gas production beginning in March 2003 from the Company's Falcon gas field in the deepwater Gulf of Mexico, (iii) increased production from Argentina primarily resulting from the resumption of oil drilling activities in the third quarter of 2002, (iv) oil production beginning in May 2003 from the Company's Adam field in Tunisia and (v) oil production beginning in August 2003 from the Company's Sable field offshore South Africa. These increases more than offset normal production declines. During 2002, the Company's average daily oil, NGL and gas production decreased primarily due to normal production declines, reduced Argentine demand for gas, the Company's curtailment of Argentine drilling activities during the first half of 2002 and the December 2001 sale of the Company's Rycroft/Spirit River field in Canada. Production, price and cost information with respect to the Company's properties for each of the years ended December 31, 2004, 2003 and2002 is set forth under "Item 2. Properties - Selected Oil and Gas Information - Production, Price and Cost Data".

Drilling activities. The Company seeks to increase its oil and gas reserves, production and cash flow through exploratory and development drilling and by conducting other production enhancement activities, such as well recompletions. During the three years ended December 31, 2004, the Company drilled 1,035 gross (876.8 net) wells, 87 percent of which were successfully completed as productive wells, at a total drilling cost (net to the Company's interest) of $1.6 billion. During 2004, the Company drilled 423 gross (384.8 net) wells. The Company's current 2005 capital expenditure budget is expected to range from $900 million to $950 million. The Company has allocated the budgeted 2005 capital expenditures as follows: approximately 75 percent to development drilling and facility activities and the balance of approximately 25 percent to exploration activities.

The Company believes that its current property base provides a substantial inventory of prospects for future reserve, production and cash flow growth. The Company's proved reserves as of December 31, 2004 include proved undeveloped reserves and proved developed reserves that are behind pipe of 161.1 MMBOE of oil and NGLs and 1,356.6 Bcf of gas. Development of these proved reserves will require futurecapital 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 and drilling a portfolio of exploration opportunities. The Company's commitment to exploration has resulted in significantdiscoveries, such as the 1998 Sable oil field discovery in South Africa; the 1999 Aconcagua, 2000 Devils Tower, 2001 Falcon and 2003 Harrier, Tomahawk and Raptor discoveries in the deepwater Gulf of Mexico; and the 2002 Borj El Khadra permit discovery in the Ghadames basin onshore Southern Tunisia. The Company currently anticipates that its 2005 exploration efforts will be approximately 25 percent of total 2005 capital expenditures and will be concentrated domestically in the Gulf of Mexico and Alaska, and internationally in Africa, Argentina 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 1. Business - Risks Associated with Business Activities - 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 the years ended December 31, 2004, 2003 and 2002, the Company expended $2.6 billion (including $2.5 billion associated with the Evergreen merger), $151.0 million and $195.5 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 2004, 2003 and 2002.

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.

Asset divestitures. The Company regularly reviews its asset base for the purpose of identifying non-strategic assets, the disposition of which would increase capital resources available for other activities and create organizational and operational efficiencies. 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 the years ended December 31, 2004, 2003 and 2002, the Company's divestitures consisted of the early termination of derivative hedge contracts and the sales of oil and gas properties and other assets for net proceeds of $1.7 million, $35.7 million and $118.9 million, respectively, which resulted in net divestiture gains of $39 thousand, $1.3 million and $4.4 million, respectively. The net cash proceeds were primarily used to fund additions to oil and gas properties or to reduce the Company's outstanding indebtedness. See Note O of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for specific information regarding the Company's asset divestitures.

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

Operations by Geographic Area

The Company operates in one industry segment. During the three years ended December 31, 2004, the Company had oil and gas producing and development activities in the United States, Argentina, Canada, South Africa and Tunisia, and had exploration activities in the United States, Argentina, Canada, Equatorial Guinea, Gabon, South Africa and Tunisia. See Note S 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 the year ended December 31, 2004, the Company's primary purchasers of oil, NGLs and gas were Williams Power Company, Inc. (12 percent), Occidental Energy Marketing, Inc. (six percent), ConocoPhillips (six percent), Enterprise Products Operating L.P. (five percent) and Plains Marketing LP (four 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 derivative 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 K 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 the years ended December 31, 2004, 2003 and 2002 from the Company's commodity hedging activities and the Company's open commodity hedge positions at December 31, 2004.

Competition, Markets and Regulations

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

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

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

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

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

Environmental and health controls. The Company's operations are subject to numerous federal, state, local and foreign laws and regulations relating to environmental and health protection. These laws andregulations may require the acquisition of a permit before drilling commences, restrict the type, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas and impose substantial liabilities for pollution resulting from oil and gas operations. These laws and regulations may also restrict air emissions or other discharges resulting from the operation of gas processing plants, pipeline systems and other facilities that the Company owns. Although the Company believes that compliance with environmental laws and regulations will not have a material adverse effect on its 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, including potential criminal penalties, will not be incurred. Moreover, it is possible that other developments, such as stricter environmental laws and regulations or claims for damages to property or persons resulting from the Company's operations, could result in substantial costs and liabilities.

The Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), also known as the "Superfund" law, imposes liability, without regard to fault or the legality of the original conduct, oncertain classes of persons with respect to the release of a "hazardous substance" into the environment. These persons include the owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of hazardous substances released at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

The Company generates wastes, including hazardous wastes, that are subject to the federal Resource Conservation and Recovery Act ("RCRA") and comparable state statutes. The United States Environmental Protection Agency and various state agencies have limited the approved methods of disposal for certain hazardous and non-hazardous wastes. Furthermore, certain wastes generated by the Company's oil and gas operations that are currently exempt from treatment as hazardous wastes may in the future be designated as hazardous wastes, and therefore be subject to more rigorous and costly operating and disposal requirements.

The Company currently owns or leases, and has in the past owned or leased, properties that for many years have been used for the exploration and production of oil and gas 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 wastes have been taken for disposal. In addition, some of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes was not under the Company's control. These properties and the wastes disposed thereon may be subject to CERCLA, RCRA and analogous state and foreign 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. 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 pipe scale and in 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 regulation of NORM has minimal effect on the Company's operations because the Company generates only small quantities of NORM on an annual basis.

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

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

Risks Associated with Business Activities

The nature of the business activities conducted by the Company subjects it to certain hazards and risks. The following is a summary of some of the material risks relating to the Company's business activities.

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

Drilling activities. Drilling involves numerous risks, including the risk that no commercially productive oil or gas reservoirs will be encountered. The cost of drilling, completing and operating wells is often uncertain and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including unexpected drilling conditions, pressure or irregularities in formations, equipment failures or accidents, adverse weather conditions and shortages or delays in the delivery of equipment. The Company's future drilling activities may not be successful and, if unsuccessful, such failure could have an adverse effect on the Company's future results of operations and financial condition. While all drilling, whether developmental or exploratory, involves these risks, exploratory drilling involves greater risks of dry holes or failure to find commercial quantities of hydrocarbons. Because of the percentage of the Company's capital budget devoted to higher risk exploratory projects, it is likely that the Company will continue to experience exploration and abandonment expense.

Unproved properties. At December 31, 2004 and 2003, the Company carried unproved property costs of $470.4 million and $179.8 million, respectively. Generally accepted accounting principles require 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 to assess possible environmental liabilities. All of these factors affect whether an acquisition will ultimately generate cash flows sufficient to provide a suitable return on investment. Even though the Company performs a review of the properties it seeks to acquire that it believes is consistent with industry practices, such reviews are often limited in scope.

Divestitures. The Company regularly reviews its property base for the purpose of identifying non-strategic assets, the disposition of which would increase capital resources available for other activities and create organizational and operational efficiencies. Various factors could materially affect the ability of the Company to dispose of non-strategic assets, including the availability of purchasers willing to purchase the non-strategic assets at prices acceptable to the Company.

Operation of natural gas processing plants. As of December 31, 2004, the Company owned interests in 11 natural gas processing plants and five treating facilities. The Company operates seven of the plants and all five treating facilities. There are significant risks associated with the operation of natural gas processing plants. Gas and NGLs are volatile and explosive and may include carcinogens. Damage to or misoperation of a 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. Although the Company currently maintains insurance coverage that it considers reasonable and that is similar to that maintained by comparable companies in the oil and gas industry, it is not fully insured against certain of these risks, either because such insurance is not available or because of the high premium costs associated with obtaining such insurance.

Environmental. The oil and gas business is subject to environmental hazards, such as oil spills, produced water spills, gas leaks and ruptures and discharges of toxic substances or gases that could expose the Company to substantial liability due to pollution and other environmental damage. A variety of federal, state and foreign laws and regulations govern the environmental aspects of the oil and gas business. Noncompliance with these laws and regulations may subject the Company to penalties, damages or other liabilities, and compliance may increase the cost of the Company's operations. Such laws and regulations may also affect the costs of acquisitions. See "Item 1. Business - Competition, Markets and 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, a material increase in the costs of production, development, exploration or processing or otherwise 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 term senior notes and variable rate credit facilities. The terms of the Company's borrowings under the senior notes and the credit facilities specify scheduled debt repayments and require the Company to comply with certain associated covenants and restrictions. The Company's ability to comply with the debt repayment terms, associated covenants and restrictions is dependent on, among other things, factors outside the Company's direct control, such as commodity prices, interest rates and competition for available debt financing. See Note 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, 2004 and the terms associated therewith.

The Company's ability to obtain additional financing is also impacted by the Company's debt credit ratings. 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, 2004, approximately 15 percent of the Company's proved reserves of oil, NGLs and gas were located outside the United States (12 percent in Argentina, two percent in Canada and one 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.

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 necessarily 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 difference 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,
- supply and demand of oil and gas,
- increases or decreases in consumption 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 spot prices prevailing as of the date of computation. Consequently, it may not reflect the prices ordinarily received or that will be received for oil and gas production because of seasonal price fluctuations or other varying market conditions. Standardized Measures as of any date are not necessarily indicative of future results of operations. Accordingly, estimates included herein of future net revenues may be materially different from the net revenues that are ultimately received. 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.

ITEM 2. PROPERTIES

The information included in this Report about the Company's oil, NGL and gas reserves as of December 31, 2004 and 2003 was based on reserve reports audited by Netherland, Sewell & Associates, Inc. ("NSA") for the Company's major properties in the United States, Argentina, Canada and South Africa and reserve reports prepared by the Company's engineers for all other properties. The reserve audits conducted by NSA in aggregate represented 88 percent and 87 percent of the Company's estimated proved quantities of reserves as of December 31, 2004 and 2003, respectively. The information included in this Report about the Company's oil, NGL and gas reserves as of December 31, 2002 was, in part, based on reserve reports audited by independent petroleum engineers and reserve reports prepared by the Company's engineers. These reserve audits conducted represented 71 percent of the Company's estimated proved quantities of reserves as of December 31, 2002.

The Company did not provide estimates of total proved oil and gas reserves during the years ended December 31, 2004, 2003 or 2002 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 1.0 billion BOE, 789.1 MMBOE and 736.7 MMBOE at December 31, 2004, 2003 and 2002, respectively, representing $6.6 billion, $4.6 billion and $4.1 billion, respectively, of Standardized Measure or $9.1 billion, $6.0 billion and $5.1 billion, respectively, on a pre-tax basis. The 30 percent and 45 percent increases in proved reserve volumes and Standardized Measure, respectively, during 2004 were primarily due to:

- Evergreen merger - 262.2 MMBOE,
- other 2004 acquisitions - 16.0 MMBOE,
- extensions and discoveries in:
  - Argentina - 25.8 MMBOE,
  - United States - 10.5 MMBOE,
  - Canada - 2.3 MMBOE and
  - Africa - .5 MMBOE,
- negative revisions of 14.3 MMBOE primarily due to:
  - 16.6 MMBOE due to the cancellation of the Gabon project as a result of increasing costs,
  - negative well performance in the Portezuelo Oeste gas field in Argentina, offset by
  - increased commodity prices extending the estimated economic life of various properties,
- production (including field fuel) during 2004 of 68.7 MMBOE and
- divestitures of 1.1 MMBOE.

The seven percent and 11 percent increases in proved reserve volumes and Standardized Measure, respectively, during 2003 were primarily due to two core area acquisitions, discoveries in Gabon, the deepwater Gulf of Mexico and Tunisia and positive reserve revisions due to increased commodity prices extending the estimated economic life of various properties, increased recoverable reserve estimates based on well performance and the addition of reserves resulting from the Company's expanded development drilling program. Partially offsetting these reserve additions was 2003 production of 56.5 MMBOE, including field fuel.

On a BOE basis, 65 percent of the Company's total proved reserves at December 31, 2004 were proved developed reserves. Based on reserve information as of December 31, 2004, 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, 2004:

PROVED OIL AND GAS RESERVES AND AVERAGE DAILY SALES VOLUMES

	Proved Reserves as of December 31, 2004 (a)				2004 Average Daily Sales Volumes (b)		
	Oil & NGLs (MBbls)	Gas (MMcf)	MBOE	Standardized Measure (in thousands)	Oil & NGLs (Bbls)	Gas (Mcf)	BOE
United States	363,257	3,000,335	863,313	$ 5,581,303	46,375	521,839	133,349
Argentina	33,168	560,374	126,564	647,292	10,080	121,654	30,356
Canada	4,095	119,869	24,073	276,467	1,054	41,867	8,031
Africa	8,271	-	8,271	138,013	11,676	-	11,676
Total	408,791	3,680,578	1,022,221	$ 6,643,075	69,185	685,360	183,412

(a) The gas reserves contain 271.7 Bcf of gas that will be produced and utilized as field fuel. Field fuel is gas consumed to operate field equipment (primarily compressors) prior to the gas being delivered to a sales point.

(b) The 2004 average daily sales volumes (i) do not include the field fuel produced, which averaged 4,374 BOE per day and (ii) were calculated using a 366-day year and without making pro forma adjustments for any acquisitions, divestitures or drilling activity that occurred during the year.

The following table represents the estimated timing and cash flows of developing the Company's proved undeveloped reserves as of December 31, 2004:

Years Ended December 31,	Estimated Future Production (MBOE)	Future Cash Inflows	Future Production Costs	Future Development Costs	Future Net Cash Flows
			($ in thousands)		
2005	8,534	$ 240,171	$ 28,271	$ 394,289	$ (182,389)
2006	20,625	569,708	70,596	347,878	151,234
2007	21,801	616,401	87,791	214,855	313,755
2008	22,120	613,047	90,579	183,546	338,922
2009	22,716	595,765	95,363	161,118	339,284
Thereafter	257,752	8,085,106	2,133,005	204,888	5,747,213
	353,548	$ 10,720,198	$ 2,505,605	$ 1,506,574	$ 6,708,019

Description of Properties

As of December 31, 2004, the Company has production, development and/or exploration operations in the United States, Argentina, Canada, Equatorial Guinea, Gabon, South Africa and Tunisia.

Domestic. The Company's domestic operations are located in the Permian Basin, Mid-Continent, Rocky Mountains, Alaska, Gulf of Mexico and onshore Gulf Coast areas of the United States. Approximately 75 percent of the Company's domestic proved reserves at December 31, 2004 are located in the Spraberry, Hugoton, West Panhandle and Raton fields. These mature fields generate substantial operating cash flow and some have a large portfolio of low risk infill drilling opportunities. The cash flows generated from these fields provide funding for the Company's other development and exploration activities both domestically and internationally. During the year ended December 31, 2004, the Company expended $2.9 billion in domestic acquisition, exploration and development drilling activities, $2.5 billion of which related to the Evergreen merger. The Company has budgeted approximately $700 million for domestic exploration and development drilling expenditures for 2005.

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 is 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 been adding the Wolfcamp formation at depths ranging from 9,300 feet to 10,300 feet to selected wells with successful results. The center of the Spraberry field was unitized in the late 1950s and early 1960s by the major oil companies; however, until the late 1980s there was very limited development activity in the field. The Company believes the area offers excellent opportunities to enhance oil and gas reserves because of the numerous undeveloped infill drilling locations, many ofwhich are reflected in the Company's proved undeveloped reserves, and the ability to reduce operating expenses through economies of scale.

During the year ended December 31, 2004, the Company placed 104 Spraberry wells on production and had 16 wells in progress as of December 31, 2004. The Company plans to drill approximately 150 development wells in the Spraberry field during 2005.

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 90.5 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 at or near capacity during the year ended December 31, 2004. During 2004, the Company placed 17 development wells on production and had one well in progress as of December 31, 2004. The plans for 2005 include drilling approximately 18 development wells and one potential new horizontal well.

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

West Panhandle field. The West Panhandle properties are located in the panhandle region of Texas where initial production commenced in 1918. These stable, long-lived reserves are attributable to the Red Cave, Brown Dolomite, Granite Wash and fractured Granite formations at depths no greater than 3,500 feet. The Company's gas in the West Panhandle field has an average energy content of 1,300 Btu 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.

During the year ended December 31, 2004, the Company placed 78 development wells on production and drilled three development wells and two extension wells which were determined to be unsuccessful. The West Panhandle field had 11 development wells in progress as of December 31, 2004. The Company plans to drill approximately 90 wells in the West Panhandle field during 2005.

Rocky Mountain area. The Company is one of the leading U.S. producers of coal bed methane ("CBM") with the Raton, Piceance and Uinta Basin assets acquired from Evergreen which are situated in Colorado and Utah. 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. 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. The Company also owns approximately 171,000 acres covering highly prospective regions of the Piceance and Uinta Basins. Currently, production is established from various tight sandstone, coal and shale formations. The Company has approximately 1,300 wells in these fields with an average daily gross measured production of 191 MMcf. In the fourth quarter of 2004, the Company placed 49 development wells on production and drilled two successful extension wells. Plans for 2005 include the drilling of approximately 300 development wells and 20 extension wells to establish additional prospective areas and reserves.

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

In the deepwater Gulf of Mexico, the Company has three major projects, all of which were producing or capable of producing at December 31, 2004:

- Canyon Express - The Canyon Express project is a joint development of three deepwater Gulf of Mexico gas discoveries, including the Company's TotalFinaElf-operated Aconcagua 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 during the early stages of building its exploration program 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 Canyon Express gathering system is the first in the area and provides the Company and its partners with the opportunity to collect gathering and handling revenues from the use of the system by any future discoveries in the area. The Company has plans to drill and complete an additional development well at Aconcagua during 2005.

- 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 owned a 45 percent working interest in the initial Falcon discovery and surrounding areas. During 2002, the Company purchased an additional 30 percent working interest in the project and became the operator. During 2003, the Company acquired the remaining 25 percent working interest in the project and established first Falcon production during March 2003.

  In the first quarter of 2003, the Company drilled its Harrier discovery, which was completed as a one-well subsea tie-back to the Falcon field facilities and placed on production in January 2004. In addition, during the third quarter of 2003, the Company successfully drilled the Tomahawk and Raptor prospects, which were also developed as single-well subsea tie-backs to the Falcon field facilities and placed on production in June 2004. To accommodate the incremental production from Harrier, Tomahawk and Raptor, as well as potential throughput associated with additional planned exploration, an additional parallel pipeline connecting the Falcon field to the Falcon Nest platform on the Gulf of Mexico shelf was added, doubling its capacity. In early September 2004, the Company shut in production from the Harrier field as a result of early water encroachment. The Company initiated a sidetrack well in late September to access an adjacent fault block in the field which was successful, encountering over 400 feet of gas-bearing sand. In order to capture the maximum reserves from the Raptor and Tomahawk fields, the Company delayed production from the Harrier sidetrack until the Tomahawk field was fully depleted in December 2004. Once the Harrier sidetrack was placed on production, the Falcon field production rate was reduced to continue to allow Raptor to fully deplete. Raptor is anticipated to be depleted during the first half of 2005, at which time production from Falcon will be increased. The Company operates all of the producing fields in the Falcon Corridor. Sidetrack operations are being evaluated for the Raptor field in 2005 to further increase reserve recovery. In addition, the Company plans to drill one or two Falcon Corridor exploration prospects during the first half of 2005.

- 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. Three Devils Tower wells were completed and placed on production prior to being shut-in during mid-September due to Hurricane Ivan. The Devils Tower spar sustained significant damage during Hurricane Ivan, and production from the three wellsdid not resume until late October 2004. A fourth well began producing at the end of November. The damage to the platform rig sustained during Hurricane Ivan delayed completion activities related tothe four additional wells previously drilled to develop the field. Rig repairs took 120 days, and completion activities for continued field development began late in January 2005. Pioneer maintains business interruption insurance and has filed a claim related to four wells that were expected to be completed but were delayed due to the effects of the hurricane. In the fourth quarter of 2004, the Company recorded approximately $7.5 million of estimated business interruption recovery related to its estimated 2004 production loss and should have additional insurance recoveries associated with 2005 operational impact from Hurricane Ivan. In addition, three subsea tie-back wells in the Goldfinger and Triton satellite discoveries in the Devils Tower area are expected to be jointly tied back to the Devils Tower spar with first production expected in late 2005. Production is expected to continue to increase as additional wells are individually completed from the spar over the next six months. The Company holds a 25 percent working interest in each of the above projects.

In addition to the development and exploration projects in the deepwater Gulf of Mexico described above, the Company participated in three subsalt deepwater prospects during the first half of 2004, of which one well was successful and two were noncommercial. A sidetrack well in the Dominion-operated Thunder Hawk discovery at Mississippi Canyon Block 734 encountered in excess of 300 feet of net oil pay in two high-quality reservoir zones. Murphy Exploration and Production Company is now the operator and has commenced drilling an additional well to further delineate the field. The Company owns a 12.5 percent working interest in the discovery. The Company also anticipates drilling an appraisal well during 2005 on its 2002 Ozona Deep discovery.

During January 2003, the Company announced a joint exploration agreement with Woodside Energy (USA), Inc. ("Woodside"), a subsidiary of Woodside Energy Ltd. of Australia, for a two-year drilling program over the shallow-water Texas shelf region of the Gulf of Mexico. Under the agreement, Woodside acquired a 50 percent working interest in 47 offshore exploration blocks operated by the Company. The agreement covers eight prospects and 19 leads and included five exploratory wells originally scheduled to be drilled in 2003 and three in 2004. Most of the wells to be drilled under the agreement target gas plays below 15,000 feet. The first three wells under this joint agreement were unsuccessful. The fourth well, Midway, encountered 30 feet of net gas pay and is expected to be tied back to an existing production platform with first production anticipated during the second quarter of 2005. Three other intervals with an additional 60 feet of gas bearing sands were also encountered and will require additional analysis to determine future commercial potential. The Company has a 37.5 percent working interest in this well. The fifth well that was originally scheduled to be drilled in 2003 and the three wells originally scheduled to be drilled in 2004 under the agreement, which has been extended for one additional year, were mutually agreed to be deferred until more technical work can be performed on the prospects by both companies. Additionally, the Company and Woodside are evaluating shallower gas prospects on the Gulf of Mexico shelf for possible inclusion in the 2005 drilling program.

Onshore Gulf Coast area. The Company has focused its drilling efforts in this area on the Pawnee field in the Edwards Reef trend in South Texas. The Company placed 10 development wells and two extension wells on production at Pawnee during 2004 and had two development wells and one extension well in progress at year end. The Company plans to drill approximately 12 wells in this area during 2005.

Alaska area. The Company spent $34.7 million of acquisition and seismic capital during 2004 to add to its leasehold position and expand its North Slope seismic data coverage. In June 2004, Pioneer announced that it agreed to a joint exploration program in the National Petroleum Reserve-Alaska ("NPR-A") located on the North Slope with ConocoPhillips and Anadarko Petroleum Corporation. At the federal lease sale held in June 2004, Pioneer was the high co-bidder on 63 tracts covering approximately 717,000 acres in the NPR-A Northwest Planning Area. Pioneer will participate with a 20 percent to 30 percent working interest in the acreage operated by ConocoPhillips. Pioneer also acquired a 20 percent interest in 167,000 total acres in the adjacent NPR-A Northeast Planning Area and in federal offshore blocks, including seismic and geologic data. In December 2004, Pioneer signed an exploration agreement with ConocoPhillips and Anadarko acquiring a 20 percent interest in approximately 452,000 additional acres and gaining the rights to extensive seismic and geologic data in the NPR-A Northeast Planning Area. Pioneer expects to participate in a multi-year exploration program within NPR-A and anticipates that two exploration wells will be drilled during the first half of 2005.

During the first quarter of 2005, Pioneer will also participate with a 40 percent working interest in an exploration well to evaluate the Kerr-McGee Corporation - Tuvaaq prospect. In addition, Pioneer holds a 50 percent working interest in a 130,000-acre position adjacent to and south of the giant Prudhoe Bay and Kuparuk Units and has a new 3-D seismic survey underway for completion during the first quarter of 2005.

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 into 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 barrels per day. 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 is performing front-end engineering and permitting activities to further define the scope of the project. If the additional work confirms favorable development economics, Pioneer will seek to obtain regulatory approval to develop the field in 2006 targeting first oil in 2008.

International. The Company's international operations are located in the Neuquen and Austral Basins areas of Argentina, the Chinchaga, Martin Creek, Lookout Butte and Carbon 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 Tunisia. As of December 31, 2004, approximately 12 percent, two percent and one percent of the Company's proved reserves are located in Argentina, Canada and Africa, respectively.

Argentina. The Company's Argentine production during the year ended December 31, 2004 averaged 30.4 MBOE per day, or approximately 17 percent of the Company's equivalent production. The Company's operated production in Argentina is concentrated in the Neuquen Basin which is located about 925 miles southwest of Buenos Aires and to the east of the Andes Mountains. Oil and gas are produced primarily from the Al Norte de la Dorsal, the Al Sur de la Dorsal, the Dadin, the Loma Negra - Ni, the Dos Hermanas, the Anticlinal Campamento and the Estación Fernández Oro blocks, 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 also operates and has a 50 percent working interest in the Lago Fuego field which is located in Tierra del Fuego, an island in the extreme southern portion of Argentina, approximately 1,500 miles south of Buenos Aires.

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

During the year ended December 31, 2004, the Company expended $102.5 million on Argentine development and exploration activities. The Company drilled 44 development wells and 31 extension/exploratory wells, of which 43 development wells and 21 extension/exploratory wells were successful. During 2004, the Company shot seismic covering approximately 330,000 acres. The Company plans to be more active in Argentina in 2005 with $133 million budgeted for oil and gas development and exploration activities.

Canada. The Company's Canadian producing properties are located primarily in Alberta and British Columbia, Canada. Production during the year ended December 31, 2004 averaged 8.0 MBOE per day, or approximately four percent of the Company's equivalent production. The Company continues to focus its traditional conventional development, exploration and acquisition activities in the core areas of northeast British Columbia and southern Alberta while expanding these activities to include a CBM focus in southern Alberta. The Canadian assets are geographically concentrated, predominately shallow gas and primarily operated by the Company in the following areas: Chinchaga, Martin Creek, Lookout Butte and Carbon.

Production from the Chinchaga area of northeast British Columbia is relatively dry gas from formation depths averaging 3,400 feet. In the Martin Creek area of British Columbia the production is relatively dry gas from various reservoirs ranging from 3,700 to 4,300 feet. The Lookout Butte area in southwest Alberta produces gas and condensate from the Mississippian Turner Valley formation at approximately 12,000 feet. The Carbon area in south central Alberta produces gas, CBM, condensate and minor oil from Cretaceous to Devonian formations at depths ranging from 400 to 6,500 feet.

During the year ended December 31, 2004, the Company expended $120.6 million (approximately $56.4 million associated with the Evergreen merger) on Canadian exploration, development and acquisition activities. The Company drilled three development wells and 51 exploratory/extension wells, primarily in the Chinchaga, Martin Creek and Carbon areas, of which all three developments wells and 27 exploratory/extension wells were successful. The majority of these wells were drilled in the Chinchaga and Martin Creek areas during the first quarter of 2004 as these areas are only accessible for drilling during the winter months. The remainder of these wells were drilled during the summer and fall in the Carbon area that is accessible for operations throughout the year. The Company plans to spend approximately $60 million on oil, gas and CBM development and exploration opportunities in Canada during 2005.

The Company previously announced its intention to divest of its Martin Creek and Lookout Butte assets in 2005. The expectation is that sales proceeds will exceed $100 million based on today's commodity price environment, however, no assurance can be given that purchasers will bid for these assets at prices that are acceptable to the Company.

Africa. In Africa, the Company has entered into agreements to explore for oil and gas in South Africa, Equatorial Guinea, Gabon and Tunisia. The amended South African agreements cover over five million acres along the southern coast of South Africa, generally in water depths less than 650 feet. The Gabon agreement covers 313,937 acres off the coast of Gabon, generally in water depths less than 100 feet. The Tunisian agreements can be separated into 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 212,420 acres and 969,755 acres, respectively, in which the Company has a 28 percent and 40 percent working interest, respectively. All permits are onshore southern Tunisia. During the year ended December 31, 2004, the Company expended $74.9 million of acquisition, development and exploration drilling and seismic capital in South Africa, Gabon, Equatorial Guinea, Tunisia and other prospective areas.

South Africa. The Company spent $9.5 million of capital associated with its Petro SA-operated Sable oil field. The Sable oil field began producing in August 2003. The Company has a 40 percent working interest in the Sable field. In 2005, the Company currently plans to spend approximately $1 million in South Africa for production enhancement opportunities at Sable.

In 2005, the Company expects its South African gas project to be sanctioned by all parties. If approved, this project will allow the Company to sell its gas from the Sable field and provide commercialization opportunities for previous gas discoveries.

Equatorial Guinea. The Company spent $13.0 million of acquisition and drilling capital during 2004 to acquire a 50 percent working interest in 244,881 acres of Block H offshore Equatorial Guinea. The Bravo 1 well was drilled in June 2004 and determined to be noncommercial. The Company has several other prospects on the block that are being evaluated for future drilling, one of which is expected to be drilled during 2005.

Gabon. The Company spent $20.7 million of capital during 2004 to drill five exploration wells, one of which was initially evaluated as successful in extending the planned development area to the south. The remaining four wells were unsuccessful. Despite the successful extension well, in October 2004, the Company canceled the development of the Olowi field due to a substantial increase in projected development costs which resulted in the project not offering competitive returns. The Company's current Gabonese permit expires in April 2005. The Company has verbally requested an extension to the permit to allow more time for the Company to determine the best manner to exit Gabon, however, no assurance can be given that such extension will be granted. In 2004, the Company recognized an impairment charge of approximately $39.7 million.

Tunisia. The Company spent $17.0 million of acquisition, drilling and seismic capital during the year ended December 31, 2004 primarily to drill one successful development well in its Adam oil field, one successful development well in its Hawa oil field and one successful exploratory well in its Dalia oil field, all within the ENI-operated Adam Concession. Production from the Adam Concession began in May 2003. The capital budget for Tunisia in 2005 of approximately $24 million includes an exploration well in the Adam concession, one exploration well on the Company-operated El Hamra permit and two appraisal wells on the Anaguid permit.

Selected Oil and Gas Information

The following tables set forth selected oil and gas information for the Company as of and for each of the years ended December 31, 2004, 2003 and 2002. Because of normal production declines, increased or decreased drilling activities and the effects of past and future acquisitions or divestitures, the historical information presented below should not be interpreted as being indicative of future results.

Production, price and cost data. The following table sets forth production, price and cost data with respect to the Company's properties for the years ended December 31, 2004, 2003 and 2002:

PRODUCTION, PRICE AND COST DATA

	Year Ended December 31,													
	2004					2003					2002			
	United States	Argentina	Canada	Africa	Total	United States	Argentina	Canada	Africa	Total	United States	Argentina	Canada	Total
Production information:														
Annual sales volumes:														
Oil (MBbls)	9,750	3,123	50	4,274	17,197	8,952	3,171	40	723	12,886	8,555	2,914	45	11,514
NGLs (MBbls)	7,224	566	336	-	8,126	7,423	481	331	-	8,235	7,487	254	345	8,086
Gas (MMcf)	190,994	44,525	15,323	-	250,842	154,400	34,357	15,209	-	203,966	77,199	28,550	17,653	123,402
Total (MBOE)	48,806	11,110	2,939	4,274	67,129	42,108	9,378	2,906	723	55,115	28,908	7,926	3,333	40,167
Average daily sales volumes:														
Oil (Bbls)	26,637	8,534	137	11,676	46,984	24,525	8,687	111	1,981	35,304	23,437	7,984	124	31,545
NGLs (Bbls)	19,738	1,546	917	-	22,201	20,338	1,318	906	-	22,562	20,512	696	946	22,154
Gas (Mcf)	521,839	121,654	41,867	-	685,360	423,013	94,128	41,669	-	558,810	211,502	78,220	48,365	338,087
Total (BOE)	133,349	30,356	8,031	11,676	183,412	115,364	25,694	7,962	1,981	151,001	79,201	21,716	9,131	110,048
Average prices, including hedge results:														
Oil (per Bbl)	$ 29.41	$ 28.06	$ 44.83	$ 38.12	$ 31.38	$ 25.25	$ 25.62	$ 29.10	$29.52	$ 25.59	$ 23.66	$ 20.63	$ 22.26	$ 22.89
NGLs (per Bbl)	$ 25.07	$ 29.91	$ 30.87	$ -	$ 25.65	$ 19.04	$ 22.85	$ 24.80	$ -	$ 19.50	$ 13.77	$ 14.56	$ 16.77	$ 13.92
Gas (per Mcf)	$ 5.15	$ .66	$ 4.64	$ -	$ 4.33	$ 4.47	$ .56	$ 4.93	$ -	$ 3.84	$ 3.16	$ .48	$ 3.41	$ 2.58
Revenue (per BOE)	$ 29.75	$ 12.07	$ 28.49	$ 38.12	$ 27.30	$ 25.10	$ 11.87	$ 29.05	$29.52	$ 23.11	$ 19.01	$ 9.79	$ 20.12	$ 17.29
Average prices, excluding hedge results:														
Oil (per Bbl)	$ 39.59	$ 29.82	$ 44.83	$ 38.71	$ 37.61	$ 29.58	$ 26.31	$ 29.10	$30.07	$ 28.80	$ 23.85	$ 20.33	$ 22.26	$ 22.95
NGLs (per Bbl)	$ 25.07	$ 29.91	$ 30.87	$ -	$ 25.65	$ 19.04	$ 22.85	$ 24.80	$ -	$ 19.50	$ 13.77	$ 14.56	$ 16.77	$ 13.92
Gas (per Mcf)	$ 5.72	$ .66	$ 5.75	$ -	$ 4.83	$ 4.92	$ .56	$ 5.30	$ -	$ 4.25	$ 3.01	$ .48	$ 3.32	$ 2.52
Revenue (per BOE)	$ 34.01	$ 12.56	$ 31.89	$ 38.71	$ 30.77	$ 27.69	$ 12.10	$ 30.98	$30.07	$ 25.24	$ 18.66	$ 9.68	$ 19.63	$ 16.97
Average costs (per BOE):														
Production costs:														
Lease operating	$ 3.45	$ 2.75	$ 9.69	$ 7.37	$ 3.86	$ 3.20	$ 2.57	$ 9.49	$ 3.87	$ 3.42	$ 3.42	$ 1.61	$ 7.50	$ 3.40
Taxes:														
Ad valorem	.58	-	-	-	.42	.53	-	-	-	.41	.78	-	-	.56
Production	.83	.23	-	-	.64	.79	.20	-	.12	.64	.74	.13	-	.56
Workover	.25	.01	.95	-	.23	.16	.01	.43	-	.15	.29	.01	.59	.26
Total	$ 5.11	$ 2.99	$ 10.64	$ 7.37	$ 5.15	$ 4.68	$ 2.78	$ 9.92	$ 3.99	$ 4.62	$ 5.23	$ 1.75	$ 8.09	$ 4.78
Depletion expense	$ 8.61	$ 5.56	$ 10.93	$ 11.19	$ 8.37	$ 7.08	$ 4.96	$ 9.98	$10.69	$ 6.92	$ 4.85	$ 5.00	$ 8.36	$ 5.17

- These amounts represent the Company's historical results from operations without making pro forma adjustments for any acquisitions, divestitures or drilling activity that occurred duringthe respective years.
- During 2004, the Company changed its treatment of field fuel, which is gas consumed to operate field equipment, to exclude the field fuel gas from sales volumes, oil and gas revenues and production costs. In prior years, the field fuel gas was included in sales volumes, oil and gas revenues and production costs. The prior period amounts have been adjusted to reflect the Company's current treatment of field fuel. Accordingly, the gas sales volumes above represent gas available for sale. These amounts will not agree to the reserve volume tables in the "Unaudited Supplemental Data" section included in "Item 8. Financial Statements and Supplemental Data" because field fuel volumes are included in production volumes in the reserve volume tables. See Note B of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplemental Data" for additional discussion.
- During 2004, the Company changed its treatment of Canadian gas transportation costs to include these costs as a component of oil and gas production costs. In prior years, transportation costs were recorded as a reduction to oil and gas revenues. The prior period amounts have been adjusted to reflect the Company's current treatment of Canadian gas transportation costs. See Note B of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplemental Data" for additional discussion.
- The Company's lower average prices received for its Argentine commodities, as compared to the prices received in other countries, is 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 has allowed gas prices to increase gradually over time, but other than those specific increases already established for gas prices in 2005, 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.

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, 2004, 2003 and 2002:

PRODUCTIVE WELLS (a)

	Gross Productive Wells			Net Productive Wells		
	Oil	Gas	Total	Oil	Gas	Total
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
As of December 31, 2002:						
United States	3,448	1,952	5,400	2,745	1,855	4,600
Argentina	694	208	902	534	142	676
Canada	1	246	247	1	197	198
Africa	5	-	5	2	-	2
Total	4,148	2,406	6,554	3,282	2,194	5,476

(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, 2004, the Company owned interests in 335 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, 2004:

LEASEHOLD ACREAGE

	Developed Acreage		Undeveloped Acreage		Royalty
	Gross Acres	Net Acres	Gross Acres	Net Acres	Acreage
United States:					
Onshore	1,340,476	1,148,765	458,955	349,065	286,048
Offshore	114,573	53,078	2,122,351	1,130,895	10,500
	1,455,049	1,201,843	2,581,306	1,479,960	296,548
Argentina	728,000	333,000	1,139,000	1,056,000	-
Canada	280,000	198,000	504,000	371,000	30,000
Africa	222,020	63,318	11,406,804	6,611,566	-
Total	2,685,069	1,796,161	15,631,110	9,518,526	326,548

The following table sets forth the expiration dates of the leases on the Company's gross and net undeveloped acres as of December 31, 2004:

	Acres Expiring (a)	
	Gross	Net
2005 (b)	3,928,789	3,038,128
2006	3,073,584	1,580,639
2007	5,118,053	2,441,124
2008	190,249	172,005
2009	576,433	183,463
Thereafter	2,744,002	2,103,167
Total	15,631,110	9,518,526

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

(b) Acres subject to expiration during 2005 include 1.8 million gross and net acres in South Africa block 14, 1.7 million gross acres (.8 million net acres) in Tunisia, 314 thousand gross and net acres in Gabon and 179 thousand gross acres (131 thousand net acres) in North America. The Company may extend these leases prior to their expiration based upon 2005 planned activities or for other business reasons. However, no assurance can be given that such lease extensions will be granted. 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. See "Description of Properties" above for information regarding the Company's drilling operations.

Drilling activities. The following table sets forth the number of gross andnet productive and dry hole wells in which the Company had an interest that were drilled during the years ended December 31, 2004, 2003 and 2002. 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 reservesgenerated 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,		
	2004	2003	2002	2004	2003	2002
United States:						
Productive wells:						
Development	268	244	148	243.1	210.5	83.0
Exploratory	8	4	6	5.3	4.0	2.0
Dry holes:						
Development	3	6	4	3.0	6.0	3.7
Exploratory	6	6	3	3.0	3.6	2.1
	285	260	161	254.4	224.1	90.8
Argentina:						
Productive wells:						
Development	43	29	13	41.7	29.0	13.0
Exploratory	21	21	9	21.0	21.0	9.0
Dry holes:						
Development	1	2	1	1.0	2.0	1.0
Exploratory	10	9	8	9.5	9.0	8.0
	75	61	31	73.2	61.0	31.0
Canada:						
Productive wells:						
Development	3	7	13	3.0	7.0	10.4
Exploratory	27	16	9	24.5	14.9	9.0
Dry holes:						
Development	-	7	4	-	6.5	4.0
Exploratory	24	26	3	23.3	21.1	3.0
	54	56	29	50.8	49.5	26.4
Africa:						
Productive wells:						
Development	2	1	4	.6	.3	1.6
Exploratory	2	1	4	1.4	.4	3.4
Dry holes:						
Development	-	-	-	-	-	-
Exploratory	5	4	-	4.4	3.5	-
	9	6	8	6.4	4.2	5.0
Total	423	383	229	384.8	338.8	153.2
Success ratio (a)	88%	84%	90%	89%	85%	86%

(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, 2004:

	Gross Wells	Net Wells
United States:		
Development	32	28.7
Exploratory	9	4.4
	41	33.1
Argentina:		
Development	6	5.4
Exploratory	8	7.4
	14	12.8
Canada:		
Development	2	2.0
Exploratory	21	17.0
	23	19.0
Africa:		
Development	-	-
Exploratory	2	.8
	2	.8
Total	80	65.7

ITEM 3. LEGAL PROCEEDINGS

The Company is party to various legal proceedings, which are described under "Legal actions" in Note J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data". The Company is also party to other litigation incidental to its business. Except for the specific legal actions described in Note J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplemental Data", the Company believes that the probable damages from such other legal actions will not be in excess of 10 percent of the Company's current assets.

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 2004.

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 following table sets forth, for the periods indicated, the high and low sales prices for the Company's common stock, as reported in the NYSE composite transactions. The Company's board of directors declared dividends to the holders of the Company's common stock of $.20 per share during the year ended December 31, 2004. On February 17, 2005, the Company's board of directors declared a cash dividend on common stock of $.10 per share, payable on April 15, 2005 to stockholders of record on March 31, 2005. The Company's board of directors did not declare dividends to the holders of the Company's common stock during the year ended December 31, 2003.

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, 2004 and 2003:

	High	Low	Dividends Declared Per Share
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
Year ended December 31, 2003:			
Fourth quarter	$ 32.90	$ 25.00	$ -
Third quarter	$ 26.52	$ 22.76	$ -
Second quarter	$ 28.44	$ 22.85	$ -
First quarter	$ 27.44	$ 23.27	$ -

On February 18, 2005, the last reported sales price of the Company's common stock, as reported in the NYSE composite transactions, was $40.11 per share.

As of February 18, 2005, the Company's common stock was held by approximately 26,600 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, 2004:

	(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	3,514,559	$ 20.19	8,307,237
Employee Stock Purchase Plan	-	$ -	557,335
Predecessor plans	1,666,025	$ 15.26	-
	5,180,584		8,864,572

(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 10 percent of the total number of shares of common stock equivalents outstanding less the total number of shares of common stock subject to outstanding awards under any stock-based plan for the directors, officers or employees of the Company. The number of remaining securities available for future issuance under the Company's Employee Stock Purchase Plan is based on the original authorized issuance of 750,000 shares less 192,665 cumulative shares issued through December 31, 2004. 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) There are no equity compensation plans that have not 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, 2004:

Period	Total Number of Shares (or Units) Purchased	Average Price Paid per Share (or Unit)	Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs
October 2004	300,000	$ 33.173	300,000
November 2004	556,500	$ 33.030	556,500
December 2004	798,600	$ 34.331	798,600
Total	1,655,100	$ 33.684	1,655,100

During December 2003, the Company's board of directors approved a $200 million share repurchase program. During January 2005, the Company's board of directors terminated the $200 million share repurchase program and approved a new share repurchase program authorizing the purchase of up to $300 million of the Company's common stock.

ITEM 6. SELECTED FINANCIAL DATA

The following selected consolidated financial data as of and for each of the five years ended December 31, 2004 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,				
	2004	2003	2002	2001	2000
	(in millions, except per share data)				
Statements of Operations Data:					
Revenues and other income:					
Oil and gas (a)	$ 1,832.7	$ 1,273.9	$ 694.4	$ 831.7	$ 822.9
Interest and other	14.1	12.3	11.2	21.8	25.8
Gain on disposition of assets, net	-	1.3	4.4	7.7	34.2
	1,846.8	1,287.5	710.0	861.2	882.9
Costs and expenses:					
Oil and gas production (a)	345.5	254.8	192.1	194.4	159.5
Depletion, depreciation and amortization	574.9	390.8	216.4	222.6	214.9
Impairment of oil and gas properties (b)	39.7	-	-	-	-
Exploration and abandonments	181.7	132.8	85.9	127.9	87.5
General and administrative	80.5	60.5	48.4	37.0	33.3
Accretion of discount on asset retirement obligations (c)	8.2	5.0	-	-	-
Interest	103.4	91.4	95.8	131.9	162.0
Other (d)	33.7	21.4	39.6	43.4	79.5
	1,367.6	956.7	678.2	757.2	736.7
Income before income taxes and cumulative effect of change in accounting principle	479.2	330.8	31.8	104.0	146.2
Income tax benefit (provision) (e)	(166.3)	64.4	(5.1)	(4.0)	6.0
Income before cumulative effect of change in accounting principle	312.9	395.2	26.7	100.0	152.2
Cumulative effect of change in accounting principle, net of tax (c)	-	15.4	-	-	-
Net income	$ 312.9	$ 410.6	$ 26.7	$ 100.0	$ 152.2
Income before cumulative effect of change in accounting principle per share:					
Basic	$ 2.50	$ 3.37	$ .24	$ 1.01	$ 1.53
Diluted	$ 2.46	$ 3.33	$ .23	$ 1.00	$ 1.53
Net income per share:					
Basic	$ 2.50	$ 3.50	$ .24	$ 1.01	$ 1.53
Diluted	$ 2.46	$ 3.46	$ .23	$ 1.00	$ 1.53
Weighted average shares outstanding:					
Basic	125.2	117.2	112.5	98.5	99.4
Diluted	127.5	118.5	114.3	99.7	99.8
Dividends declared per share	$ .20	$ -	$ -	$ -	$ -
Balance Sheet Data (as of December 31):					
Total assets	$ 6,647.2	$ 3,951.6	$ 3,455.1	$ 3,271.1	$ 2,954.4
Long-term obligations and minority interests	$ 3,271.0	$ 1,762.0	$ 1,805.6	$ 1,757.5	$ 1,833.0
Total stockholders' equity	$ 2,831.8	$ 1,759.8	$ 1,374.9	$ 1,285.4	$ 904.9

(a) Certain amounts for periods prior to January 1, 2004 have been reclassified to conform with the current year presentation. See Note B of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplemental Data" for additional discussion.

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

(c) Cumulative effect of change in accounting principle for 2003 relates to the adoption of SFAS No. 143 on January 1, 2003. Associated therewith, the Company recorded accretion of discount on asset retirement obligations in accordance with SFAS No. 143 during 2004 and 2003. See Notes B and M of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data".

(d) Other expense for 2003, 2002, 2001 and 2000 include losses on the early extinguishment of debt of $1.5 million, $22.3 million, $3.8 million and $12.3 million, respectively. Other expense for 2001 and 2000 include noncash mark-to-market charges for changes in the fair values of non-hedge financial instruments of $11.5 million and $58.5 million, respectively. See Note P 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 Q 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

2004 Highlights and Events

Pioneer's financial and operating performance for the year ended December 31, 2004 included the following highlights and events:

- Average daily sales volumes on a BOE basis increased 21 percent in 2004 as compared to 2003, principally due to a full year of production from the Falcon and Sable development projects, new production being initiated from the Harrier, Raptor and Tomahawk fields in the Falcon area and at Devils Tower and fourth quarter production added from the Evergreen merger.
- Oil and gas revenues increased 44 percent in 2004 as a result of the increased production volumes and increases in worldwide oil and gas prices.
- Income before income taxes and cumulative effect of change in accounting principle increased by 45 percent to $479.2 million from $330.8 million in 2003.
- Net cash provided by operating activities increased by 45 percent to a record $1.1 billion as compared to $763.7 million in 2003.
- The Company's capital investment programs resulted in total proved reserves of 1.0 billion BOE at December 31, 2004.
- The declaration of $.20 per share of common dividends.
- A $39.7 million impairment charge ($12.8 million net of tax benefits) as a result of the decision to cancel Gabonese Olowi field development plans. See Note T of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for more information pertaining to this matter.
- Partial loss of third and fourth quarter production at Devils Tower and Canyon Express from Hurricane Ivan which struck on September 15, 2004 and related damages.
- The 2004 repurchase of 2.8 million shares of the Company's common stock for $92 million.

During 2004, the Company also announced the following financial and operating achievements:

- Rating agencies upgrade of the Company to investment grade status in response to improved financial position and earnings trends, along with other factors specific to the Company.
- Merger with Evergreen. See Note C of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" and "Evergreen Merger" below for information regarding this business combination.
- The exchange of portions of the Company's higher-yielding senior notes for 5.875% senior notes due 2016 (the "New Notes") and cash. See Note F of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" and "Capital Commitments, Capital Resources and Liquidity" below for information regarding this $526.8 million debt exchange that was completed in July 2004.
- Completion of the first amendment (the "First Amendment") to the Company's $700 million, five-year revolving credit agreement (the "Revolving Credit Agreement") which removed Pioneer Natural Resources USA, Inc., a wholly-owned subsidiary of the Company ("Pioneer USA"), as a guarantor of the Revolving Credit Agreement and had the effect of removing Pioneer USA as a guarantor of the Company's senior notes. See Note F of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information regarding the First Amendment.
- Completion of a successful appraisal well in the Hawa area in the Adam production concession onshore southern Tunisia.
- First production from the Company's deepwater Gulf of Mexico Harrier field during January 2004, the Devils Tower field during May 2004 and the Raptor and Tomahawk fields during June 2004.
- The acquisition of a 50 percent interest in Block H offshore Equatorial Guinea, West Africa.
- The announced agreement to participate in a joint exploration program with ConocoPhillips and Anadarko Petroleum Corporation in the National Petroleum Reserve on the North Slope of Alaska.

2004 Financial and Operating Performance

During the years ended December 31, 2004, 2003 and 2002, the Company recorded net income of $312.9 million, $410.6 million and $26.7 million ($2.46, $3.46 and $.23 per diluted share), respectively. Compared to 2003, the Company's 2004 total revenues and other income increased by $559.4 million, or 43 percent, including a $558.8 million increase in oil and gas revenues. The increase in oil and gas revenues was due to increases in production volumes and increases of 23 percent, 32 percent and 13 percent in average oil, NGL and gas prices, respectively, including the effects of commodity price hedges.

Compared to 2003, the Company's total costs and expenses increased by $410.9 million, or 43 percent, during the year ended December 31, 2004. The increase in total costs and expenses was primarily reflective of a $184.0 million increase in depletion, depreciation and amortization ("DD&A") expense, primarily driven by increases in depletion associated with increased production volumes from higher-cost-basis deepwater Gulf of Mexico and South Africa properties, a $90.8 million increase in oil and gas production costs, which primarily resulted from increases in production volumes, the strengthening of both the Argentine peso and Canadian dollar and commodity prices that impacted variable lease operating expenses and production taxes, a $48.9 million increase in exploration and abandonments expense primarily due to increased exploration/extension drilling in the Gulf of Mexico, Argentina, Canada and Gabon and a $39.7 million impairment charge on the Company's Gabonese properties.

During the year ended December 31, 2004, the Company's net cash provided by operating activities increased to $1.1 billion, as compared to $763.7 million during 2003 and $332.2 million during 2002. The 45 percent increase in net cash provided by operating activities during 2004 was primarily due to increases in production volumes and commodity prices, as discussed above.

During the year ended December 31, 2004, successful capital investment activities increased the Company's proved reserves to 1.0 billion BOE, reflecting the effects of the Evergreen merger, strategic acquisitions of property interests in the Company's core operating areas and the Company's 2004 drilling program. Costs incurred for the year ended December 31, 2004 totaled $3.2 billion, including $2.6 billion of proved and unproved property acquisitions, $557.2 million of exploration and development drilling and seismic expenditures and $15.1 million of asset retirement obligations. Costs incurred for the year ended December 31, 2004 include $2.5 billion of costs to acquire Evergreen's oil and gas properties.

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

Evergreen Merger

On September 28, 2004, Pioneer completed its 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 262.2 MMBOE. Evergreen was a publicly-traded independent oil and gas company primarily engaged in the production, development, exploration and acquisition of North American unconventional gas. Evergreen was based in Denver, Colorado 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. 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.

2005 Outlook and Activities

Volumetric production payments. During January 2005, the Company sold two percent of its total proved reserves, or 20.5 million BOE of proved reserves, by means of two volumetric production payments ("VPPs") for total proceeds of $593 million and the assumption of the Company's obligations under certain derivative hedge agreements. Proceeds from the VPPs were initially used to pay down indebtedness.

The 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 to the purchaser and (v) allows the Company to retain the assets after the VPP's volumetric obligations have been satisfied.

The first VPP sells 58 Bcf of Hugoton field gas volumes over an expected five-year term beginning in February 2005 for $275 million of proceeds. The second VPP sells 10.8 MMBOE of Spraberry field oil volumes over an expected seven-year term beginning in January 2006 for $318 million of proceeds.

A VPP is considered a sale of proved reserves and the related future production of those proved reserves. As a result the Company will (i) remove the proved reserves associated with the VPPs; (ii) recognize the VPP proceeds as deferred revenue which will be amortized on a unit-of-production basis to future oil and gas revenues over the terms of the VPPs; (iii) retain responsibility for 100 percent of the production costs and capital costs related to VPP interests and (iv) no longer recognize production associated with the VPP volumes, resulting in higher future revenue per BOE, production costs per BOE and DD&A per BOE ratios.

The Company will amortize to oil and gas revenues $62.9 million of net deferred gas revenue during 2005 associated with the Hugoton field VPP. During 2006, the Company will amortize $57.6 million of net deferred gas revenue associated with the Hugoton field VPP and $53.7 million of net deferred oil revenue associated with the Spraberry field VPP.

Commodity prices. World oil prices increased during the year ended December 31, 2004 in response to political unrest and supply disruptions in Iraq and Venezuela as well as other supply and demand factors. North American gas prices also increased during 2004 in response to continued strong supply and demand fundamentals. The Company's outlook for 2005 commodity prices continues to be cautiously optimistic. Significant factors that will impact 2005 commodity prices include developments in Iraq 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 K 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, 2004. Also see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for disclosures about the Company's commodity related derivative financial instruments.

Capital expenditures. During 2005, the Company's budget for oil and gas capital activities is expected to range from $900 million to $950 million, of which approximately 75 percent has been budgeted for lower-risk development and extension drilling and facility costs and 25 percent for exploration expenditures. The Company's 2005 capital budget is allocated approximately 75 percent to the United States, 15 percent to Argentina and five percent to each of Africa and Canada. Pioneer expects to drill approximately 800 exploration and development wells during 2005. During 2005 and 2006, the Company expects to expend approximately $394 million and $348 million, respectively, of capital for development drilling and facility costs related to its proved undeveloped reserves.

Production growth. The Company expects that its annual 2005 worldwide production will range from 70 MMBOE to 74 MMBOE, or approximately 192 MBOE to 203 MBOE per day. The forecasted range includes a full year of production from the assets acquired in the Evergreen merger and has been reduced by the VPP volumes sold during January 2005. The Company expects, based on quoted futures prices, to generate cash flow significantly in excess of its capital program which will further enhance the Company's financial flexibility to fund the development of future exploration successes, core area acquisitions and additional development drilling.

With several discoveries in various stages of commercialization, a pipeline of exploration opportunities, the potential for continued core area acquisitions, continuing strong commodity prices and significant excess cash flow, Pioneer has targeted five-year average compounded annual production growth of eight percent to nine percent or ten percent per share, giving consideration to contemplated share repurchases.

Costs and expenses. The Company expects that its costs and expenses that are highly correlated with production volumes, such as production costs and depletion expense, will increase in absolute amounts during 2005 and that production costs, depreciation, depletion and amortization expense and other costs and expenses will increase on a per BOE basis as a result of the sale of proved reserves through the VPPs. Additionally, the Company expects that depletion expense will increase on a per BOE basis during 2005 as compared to 2004 due to increased production from the Devils Tower oil field in the deepwater Gulf of Mexico and the assets acquired in the Evergreen merger. The per BOE cost basis of these fields is higher than that of Pioneer's average producing property in 2004. Ad valorem taxes are highly correlated with prior year commodity prices. As a consequence of increases in oil, NGL and gas prices during 2004, ad valorem taxes are expected to be higher in 2005, as compared to 2004. The Company also anticipates an increase in general and administrative expenses during 2005 due to additional staffing associated with the Evergreen merger and anticipated Company growth, as well as the amortization of deferred compensation associated with unvested restricted stock and stock options.

Capital allocation. During 2004, the Company improved its financial position and achieved investment grade standards. The Company is now targeting mid-investment grade ratings. Towards that end, the Company established a targeted range for debt to book capitalization of less than 35 percent by the end of 2005, as further discussed later. During 2004, the Company paid dividends of $.20 per common share in two semiannual installments of $.10 per common share, and the Company currently expects to, as a minimum, maintain this level of dividends in 2005.

During 2005 through 2007, the Company anticipates, based upon year-end futures prices, that it will have significant excess cash flow after funding its typical annual capital budgets, planned dividends and achieving its leverage targets. The Company considers it a high priority to utilize a portion of the excess cash flow to fund the development of new exploration successes and to selectively acquire additional assets in its core areas. The Company will also use a portion of the excess cash flow for share repurchases, pursuant to the recently approved $300 million stock repurchase program.

First quarter 2005. Based on current estimates, the Company expects that first quarter 2005 production will average 175,000 to 190,000 BOE per day. This range is lower than the fourth quarter average reflecting the VPP volumes sold, more days of downtime and a gradual ramp up of production for the Canyon Express system which has been undergoing repairs, the timing of oil cargo shipments in Tunisia and South Africa which were high during the fourth quarter, and the typical seasonal decline in gas demand during Argentina's summer season.

First quarter production costs (including production and ad valorem taxes) are expected to average $6.00 to $6.50 per BOE based on current NYMEX strip prices for oil and gas. The increase over the prior quarter is a result of the retention of operating costs related to the VPP volumes sold, an increase in production and ad valorem taxes and additional workovers planned during the Canadian winter access season. Production costs are expected to decline in the second quarter of 2005 as lower-cost volumes resume from the deepwater Gulf of Mexico and workovers return to more normal levels. Depreciation, depletion and amortization expense is expected to average $8.75 to $9.25 per BOE.

Total exploration and abandonment expense is expected to be $80 million to $110 million. Several higher-risk exploration wells and significant seismic investments are planned during the first quarter, serving to front-end load the Company's 2005 exploration program. Specifically, first quarter exploration activity is expected to include an appraisal well to the 2004 Thunder Hawk discovery and an exploration well on a Falcon Corridor satellite prospect in the deepwater Gulf of Mexico. In Alaska, as many as three wells are expected to test new exploration targets and Pioneer plans to shoot seismic over newly acquired acreage. One well is planned in West Africa and lower-risk exploration and geologic and geophysical work will also continue in Argentina, Canada and Tunisia. General and administrative expense is expected to be $24 million to $26 million. Interest expense is expected to be $33 million to $36 million, and accretion of discount on asset retirement obligations is expected to be approximately $2 million to $3 million.

The Company's effective income tax rate is expected to range from 36 percent to 39 percent based on current capital spending plans, including cash income taxes of $5 million to $10 million that are principally related to Argentine and Tunisian income taxes and nominal alternative minimum tax in the U.S. Other than in Argentina and Tunisia, the Company continues to benefit from the carryforward of net operating losses and other positive tax attributes.

Debt reduction target. Although the Evergreen merger has resulted in an increase in the Company's ratio of debt to book capitalization, the Company has targeted a ratio of debt to book capitalization of less than 35 percent by the end of 2005. To achieve this target, the Company plans to apply a portion of the proceeds from the 2005 VPPs and the divestiture of certain Canadian assets for expected proceeds of over $100 million to reduce debt. In addition, the Company expects cash flows to be significantly in excess of the 2005 capital program based on current commodity prices which can be used to further reduce debt.

Field Fuel Reporting

During the fourth quarter of 2004, the Company completed a voluntary internal review of the various accounting treatments related to field fuel costs used by major oil companies and other independents in order to determine common industry practice. The review, in part, was undertaken in response to the large volume of field fuel usage related to the assets acquired from Evergreen. Field fuel is gas consumed to operate field equipment (primarily compressors) prior to the gas being delivered to a sales point.

Pioneer has historically recorded the value of field fuel as an operating expense with an equal amount recorded as oil and gas revenues, with no net income effect. Pioneer also reflected the volumes associated with field fuel in gas production. This practice has been routinely discussed by the Company, especially in relation to the rising value of the fuel used in the field and its contribution to rising field operating expenses.

Although the Company believes that its past treatment of field fuel was acceptable, the Company changed its reporting of field fuel, no longer recording it as revenue or expense and not including it as production. Pioneer believes this presentation is more common in the industry and will provide a better basis for comparing Pioneer to other oil and gas companies. Within this Report, the Company has adjusted its prior period revenues, production costs and sales volumes to reflect the new method of reporting field fuel. The change in reporting field fuel did not change reported net income of the periods presented since revenues and production costs were changed in equal amounts.

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.

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 the years ended December 31, 2004, 2003 and 2002, the Company recognized exploration, abandonment, geological and geophysical expense of $181.7 million, $132.8 million and $85.9 million, respectively, under the successful efforts method.

Proved reserve estimates. Estimates of the Company's proved reserves included in this Reportare 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, 2004, 2003 and 2002 was 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. 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 present value of future net cash flows included in this Report as of December 31, 2004 is the current market value of the Company's estimated proved reserves. In accordance with SEC requirements, the Company based the estimated present value of future net cash flows from proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate.

The Company's estimates of proved reserves materially impact depletion expense. If the estimates of proved reserves decline, the rate at which the Company records depletion expense will increase, reducing future net income. Such a decline may result from lower market prices, which may make it 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 impact 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 if the required capital expenditure is made.
(ii) Drilling of the additional exploratory wells is under way or firmly planned for the near future.

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 evaluatethe future potential of the exploration well and economics associated with making a determination on its commercial viability. In these instances, the projects 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, 2004 and 2003 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 a United States deferred tax asset valuation allowance in a future period. As of December 31, 2004, the Company does not believe there is sufficient positive evidence to reverse its valuation allowances related to foreign tax jurisdictions.

Goodwill impairment. The Company will review 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.

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 J 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.

Results of Operations

Oil and gas revenues. Revenues from oil and gas operations totaled $1.8 billion during 2004, as compared to $1.3 billion during 2003 and $694.4 million during 2002, representing a 44 percent increase from 2003 to 2004. The revenue increase from 2003 to 2004 was due to a 21 percent increase in total BOE production, a 23 percent increase in oil prices, a 32 percent increase in NGL prices and a 13 percent increase in gas prices, including the effects of commodity price hedges. The revenue increase from 2002 to 2003 was due to a 37 percent increase in BOE production, a 12 percent increase in oil prices, a 40 percent increase in NGL prices and a 49 percent increase in gas prices, including the effects of commodity price hedges.

The following table provides average daily sales volumes, by geographic area and in total, for the years ended December 31, 2004, 2003 and 2002:

	Year ended December 31,		
	2004	2003	2002
Average daily sales volumes:			
Oil (Bbls)			
United States	26,637	24,525	23,437
Argentina	8,534	8,687	7,984
Canada	137	111	124
Africa	11,676	1,981	-
Worldwide	46,984	35,304	31,545
NGLs (Bbls)			
United States	19,738	20,338	20,512
Argentina	1,546	1,318	696
Canada	917	906	946
Worldwide	22,201	22,562	22,154
Gas (Mcf)			
United States	521,839	423,013	211,502
Argentina	121,654	94,128	78,220
Canada	41,867	41,669	48,365
Worldwide	685,360	558,810	338,087
Total (BOE)			
United States	133,349	115,364	79,201
Argentina	30,356	25,694	21,716
Canada	8,031	7,962	9,131
Africa	11,676	1,981	-
Worldwide	183,412	151,001	110,048

Per BOE average daily production for 2004 as compared to 2003 increased by 16 percent in the United States, by 18 percent in Argentina, by one percent in Canada and the Company realized first production from South Africa and Tunisia during 2003. The increased production was principally attributable to a full year of production from the Falcon area, new production being initiated from the Harrier, Raptor and Tomahawk fields in the Falcon area and at Devils Tower, fourth quarter production added from the Evergreen merger and to 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 production volumes being added from the Company's capital expenditures and higher oil and gas demand during their summer season.

Per BOE average daily production for 2003 as compared to 2002 increased by 46 percent in the United States, by 18 percent in Argentina and the Company realized first production from South Africa and Tunisia during 2003, while average daily production for 2003 as compared to 2002 decreased by 13 percent in Canada due to normal production decline rates. The increased production was principally attributable to incremental gas production from the deepwater Gulf of Mexico Canyon Express and Falcon area projects, initial oil production in South Africa and Tunisia and increased oil and gas production in Argentina, offset by normal production declines.

The following table provides average reported prices, including the results of hedging activities, and average realized prices, excluding the results of hedging activities, by geographic area and in total, for the years ended December 31, 2004, 2003 and 2002:

	Year ended December 31,		
	2004	2003	2002
Average reported prices:			
Oil (per Bbl)			
United States	$ 29.41	$ 25.25	$ 23.66
Argentina	$ 28.06	$ 25.62	$ 20.63
Canada	$ 44.83	$ 29.10	$ 22.26
Africa	$ 38.12	$ 29.52	$ -
Worldwide	$ 31.38	$ 25.59	$ 22.89
NGL (per Bbl)			
United States	$ 25.07	$ 19.04	$ 13.77
Argentina	$ 29.91	$ 22.85	$ 14.56
Canada	$ 30.87	$ 24.80	$ 16.77
Worldwide	$ 25.65	$ 19.50	$ 13.92
Gas (per Mcf)			
United States	$ 5.15	$ 4.47	$ 3.16
Argentina	$ .66	$ .56	$ .48
Canada	$ 4.64	$ 4.93	$ 3.41
Worldwide	$ 4.33	$ 3.84	$ 2.58
Average realized prices:			
Oil (per Bbl)			
United States	$ 39.59	$ 29.58	$ 23.85
Argentina	$ 29.82	$ 26.31	$ 20.33
Canada	$ 44.83	$ 29.10	$ 22.26
Africa	$ 38.71	$ 30.07	$ -
Worldwide	$ 37.61	$ 28.80	$ 22.95
NGL (per Bbl)			
United States	$ 25.07	$ 19.04	$ 13.77
Argentina	$ 29.91	$ 22.85	$ 14.56
Canada	$ 30.87	$ 24.80	$ 16.77
Worldwide	$ 25.65	$ 19.50	$ 13.92
Gas (per Mcf)			
United States	$ 5.72	$ 4.92	$ 3.01
Argentina	$ .66	$ .56	$ .48
Canada	$ 5.75	$ 5.30	$ 3.32
Worldwide	$ 4.83	$ 4.25	$ 2.52

Field fuel. As previously discussed, the Company changed its method of reporting field fuel usage during the fourth quarter of 2004. Accordingly, the gas revenues, production volumes and related per unit measures of all periods presented have been adjusted in accordance with the new method of reporting field fuel.

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. 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 K 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 the years ended December 31, 2004, 2003 and 2002 from the Company's hedging activities, the Company's open hedge positions at December 31, 2004 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.

Argentine commodity prices. During 2002, the Argentine government implemented a 20 percent tax on oil exports. During 2002 and 2003, the Company exported approximately 29 percent and five percent, respectively, of its Argentine oil production. Associated therewith, the Company incurred oil export taxes of $2.2 million and $1.2 million for 2002 and 2003, respectively. During 2004, 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. At December 31, 2004, the Company had $5.0 million of deferred revenue reflected in its balance sheet associated with the sales in excess of the price cap. 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 barrels as WTI prices per barrel 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 2004 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 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 $.48, $.56 and $.66 in 2002, 2003 and 2004, 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. Recently, 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 rise from a current 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 been allowed for in the current decree. 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 $14.1 million, $12.3 million and $11.2 during the years ended December 31, 2004, 2003 and 2002, respectively. The Company's interest and other income was comprised of revenue that was not directly attributable to oil and gas producing activities or oil and gas property divestitures. See Note N 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. During the years ended December 31, 2004, 2003 and 2002, the Company completed asset divestitures for net proceeds of $1.7 million, $35.7 million and $118.9 million, respectively. Associated therewith, the Company recorded gains on disposition of assets of $39 thousand, $1.3 million and $4.4 million during the years ended December 31, 2004, 2003 and 2002, respectively.

The net cash proceeds from asset divestitures during the years ended December 31, 2004, 2003 and 2002 were used, together with net cash flows provided by operating activities, to fund additions to oil and gas properties and to reduce outstanding indebtedness. See Note O 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 $345.5 million, $254.8 million and $192.1 million during the years ended December 31, 2004, 2003 and 2002, 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 the year ended December 31, 2004 by 11 percent as compared to 2003. The increase in total production costs per BOE during 2004 as compared to 2003 is 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.

Total production costs per BOE decreased during 2003 by three percent as compared to 2002, primarily due to decreases in per BOE ad valorem taxes and workover expenses, partially offset by increases in per BOE lease operating expenses and production taxes. The increase in per BOE lease operating expenses was due to the strengthening of both the Argentine peso and the Canadian dollar, Argentine inflation and higher average lifting costs incurred on South African Sable oil field production, while the increase in per BOE production taxes primarily resulted from increases in North American gas prices and world oil prices. The decrease in per BOE ad valorem taxes is primarily due to the incremental production from the deepwater Gulf of Mexico, Argentina, South Africa and Tunisia fields which are not subject to ad valorem taxes.

The following tables provide the components of the Company's total production costs per BOE and total production costs per BOE by geographic area for the years ended December 31, 2004, 2003 and 2002:

	Year Ended December 31,		
	2004	2003	2002
Lease operating expenses	$ 3.86	$ 3.42	$ 3.40
Taxes:			
Ad valorem	.42	.41	.56
Production	.64	.64	.56
Workover expenses	.23	.15	.26
Total production costs	$ 5.15	$ 4.62	$ 4.78

	Year Ended December 31,		
	2004	2003	2002
Total production costs:			
United States	$ 5.11	$ 4.68	$ 5.23
Argentina	$ 2.99	$ 2.78	$ 1.75
Canada	$ 10.64	$ 9.92	$ 8.09
Africa	$ 7.37	$ 3.99	$ -
Worldwide	$ 5.15	$ 4.62	$ 4.78

As previously discussed, the Company changed its method of reporting field fuel usage during the fourth quarter of 2004. Accordingly, the production costs and related per unit measures of all presentedperiods have been adjusted in accordance with the new method of reporting field fuel.

Depletion, depreciation and amortization expense. The Company's total DD&A expense was $8.56, $7.09 and $5.39 per BOE for the years ended December 31, 2004, 2003 and 2002, respectively. Depletion expense, the largest component of DD&A, was $8.37, $6.92 and $5.17 per BOE during the years ended December 31, 2004, 2003 and 2002, respectively, and depreciation and amortization of other property and equipment was $.19, $.17 and $.22 per BOE during each of the respective years. During 2004 and 2003, 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 by geographic area for the years ended December 31, 2004, 2003 and 2002:

	Year Ended December 31,		
	2004	2003	2002
Depletion expense:			
United States	$ 8.61	$ 7.08	$ 4.85
Argentina	$ 5.56	$ 4.96	$ 5.00
Canada	$ 10.93	$ 9.98	$ 8.36
Africa	$ 11.19	$ 10.69	$ -
Worldwide	$ 8.37	$ 6.92	$ 5.17

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 the year ended December 31, 2004, the Company recognized a noncash impairment charge of $39.7 million to reduce the carrying value of its Gabonese Olowi field assets as development of the discovery was canceled. See "Critical Accounting Estimates" above and Notes B and T 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. Exploration, abandonments, geological and geophysical costs totaled $181.7 million, $132.8 million and $85.9 million during the years ended December 31, 2004, 2003 and 2002, respectively. The following table provides the Company's geological and geophysical costs, exploratory dry hole expense, lease abandonments and other exploration expense by geographic area for the years ended December 31, 2004, 2003 and 2002:

	United States	Argentina	Canada	Africa and Other	Total
			(in thousands)		
Year ended December 31, 2004:					
Geological and geophysical costs	$ 51,731	$ 11,718	$ 4,047	$ 14,833	$ 82,329
Exploratory dry holes	39,328	7,213	11,811	24,460	82,812
Leasehold abandonments and other	7,925	4,475	4,142	6	16,548
	$ 98,984	$ 23,406	$ 20,000	$ 39,299	$ 181,689
Year ended December 31, 2003:					
Geological and geophysical costs	$ 40,783	$ 7,689	$ 4,426	$ 3,903	$ 56,801
Exploratory dry holes	27,015	2,672	10,963	20,250	60,900
Leasehold abandonments and other	4,934	7,715	2,302	108	15,059
	$ 72,732	$ 18,076	$ 17,691	$ 24,261	$ 132,760
Year ended December 31, 2002:					
Geological and geophysical costs	$ 22,761	$ 4,138	$ 3,544	$ 7,223	$ 37,666
Exploratory dry holes	32,557	3,294	1,220	(539)	36,532
Leasehold abandonments and other	7,637	2,874	1,077	108	11,696
	$ 62,955	$ 10,306	$ 5,841	$ 6,792	$ 85,894

The increase in 2004 exploration, abandonments, geological and geophysical expense, as compared to 2003, was primarily due to a $25.5 million increase in geological and geophysical expenditures and a $21.9 million increase in dry hole expense. The increase in geological and geophysical expenditures during 2004 as compared to 2003 was primarily due to expenditures supportive of exploration activities in the deepwater Gulf of Mexico, Alaska, Argentina and Africa. 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 drilled and evaluated 103 exploration/extension wells, 58 of which were successfully completed as discoveries. During 2003, the Company drilled and evaluated 87 exploration/extension wells, 42 of which were successfully completed as discoveries.

The increase in 2003 exploration, abandonments, geological and geophysical expense, as compared to 2002, was primarily due to increased geological and geophysical expenditures supportive of exploration activities in the Gulf of Mexico and Alaska and a $24.4 million increase in exploratory dry hole expense. The increase in exploratory dry hole expense during 2003 as compared to 2002 was primarily due to an increase in Canadian exploratory drilling activities and three unsuccessful wells drilled in South Africa and one unsuccessful well drilled in Tunisia.

General and administrative expenses. The Company's general and administrative expenses totaled $80.5 million ($1.20 per BOE), $60.5 million ($1.10 per BOE) and $48.4 million ($1.21 per BOE) during the years ended December 31, 2004, 2003 and 2002, respectively. 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 the three years ended December 31, 2004.

The increase in general and administrative expense during 2003, as compared to 2002, was primarily due to increases in administrative staff and performance-related compensation costs, including the amortization of restricted stock awarded to officers, directors and key employees during 2003 and 2002.

Accretion of discount on asset retirement obligations. During the years ended December 31, 2004 and 2003, the Company recorded accretion of discount on asset retirement obligations of $8.2 million and $5.0 million, respectively. The provisions of Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement

Obligations" ("SFAS 143") require that the accretion of discount on asset retirement obligations be classified in the consolidated statement of operations separate from interest expense. Prior to 2003 and the adoption of SFAS 143, the Company classified accretion of discount on asset retirement obligations as a component of interest expense. The Company's interest expense during the year ended December 31, 2002 included $2.6 million of accretion of discount on asset retirement obligations that was calculated prior to the adoption of SFAS 143 based on asset retirement obligations recorded in purchased business combinations. See Notes B and M of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's adoption of SFAS 143.

The increase in accretion of discount on asset retirement obligations for 2004 as compared to 2003 was primarily due to the increase in future plugging and abandonment obligations related to new wells in the deepwater Gulf of Mexico, Tunisia and South Africa and fourth quarter accretion of discount on asset retirement obligations associated with the Evergreen merger.

Interest expense. Interest expense was $103.4 million, $91.4 million and $95.8 million during the years ended December 31, 2004, 2003 and 2002, respectively, while the weighted average interest rate on the Company's indebtedness for the year ended December 31, 2004 was 5.4 percent as compared to 5.3 percent and 5.7 percent for the years ended December 31, 2003 and 2002, respectively, taking into account the effect of interest rate derivatives. The increase in interest expense for 2004 as compared to 2003 was primarily due to an $8.0 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.

The decrease in interest expense for 2003 as compared to 2002 was primarily due to (i) $4.8 million of interest savings associated with the July 2002 repayment of a $45.2 million West Panhandle gas field capital obligation which bore interest at an annual rate of 20 percent; (ii) $4.1 million of incremental savings from the Company's interest rate hedging program; a $2.6 million decrease in accretion expense (see "Accretion of discount on asset retirement obligations", above); and (iii) lower underlying market interest rates and outstanding debt. Partially offsetting the decreases in interest expense was a $6.8 million decrease in interest capitalized during 2003 as compared to 2002 due to the completion of the Canyon Express and Falcon area development projects.

During July 2004, the Company exchanged $526.8 million of three existing series of senior notes for a like principal amount of New Notes and cash. In accordance with GAAP, the Company accounted for the debt exchange during the third quarter of 2004 as a replacement of the exchanged debt and began amortizing a $109.0 million payment made in conjunction with the debt exchange which represented the market value of the exchanged senior notes in excess of their stated value, along with the unamortized carrying values attributable to the issuance costs, discounts and deferred hedge gains and losses of the exchanged debt, as adjustments of interest expense over the term of the New Notes.

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, the July 2004 note exchange and interest expense.

Other expenses. Other expenses were $33.7 million during the year ended December 31, 2004, as compared to $21.3 million during 2003 and $39.6 million during 2002. See Note P 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. The increase in other expense for 2004 as compared to 2003 was primarily due to incremental contingency adjustments of $11.8 million. The decrease in other expense for 2003 as compared to 2002 was primarily due to a decrease of $20.9 million in losses on early extinguishment of debt.

Income tax provisions (benefits). The Company recognized consolidated income tax provisions of $166.4 million during the year ended December 31, 2004, consolidated income tax benefits of $64.4 million during 2003 and consolidated income tax provisions of $5.1 million during 2002. The Company's consolidated income tax provisions in 2004 were comprised of a $3.1 million current United States federal, state and local tax provisions, a $22.2 million current foreign income tax provision, $143.8 million of deferred United States federal, state and local tax provisions and $2.7 million of deferred foreign tax benefits.

The Company's consolidated tax benefits in 2003 were comprised of a \$.1 million current United States federal tax provision, an \$11.1 million current foreign income tax provision, \$76.3 million of deferred United States federal, state and local tax benefits and \$.7 million of deferred foreign tax provisions. 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 consolidated tax provision for 2002 was comprised of current United States state and local taxes of \$.2 million, current foreign taxes of \$2.1 million and deferred foreign tax provisions of \$2.8 million.

The Company's 34.7 percent effective tax rate for the year ended December 31, 2004 is lower than the combined United States federal and state statutory rate of approximately 36.5 percent primarily due to the deferred tax benefit recognized associated with the Company's cancellation of the development of its Olowi field in Gabon. See Notes Q and T of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for a discussion regarding the Company's reversal of its United States deferred tax valuation allowances during 2003 and the Company's decision to cancel its development of the Olowi field in Gabon.

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

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

Payments for acquisitions, net of cash acquired. The Company paid \$880.4 million of cash, net of \$12.1 million of cash acquired, to complete the Evergreen merger during 2004. 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 of the merger with a new \$900 million 364-Day Credit Agreement (the "364-Day Credit Agreement").

Oil and gas properties. The Company's cash expenditures for additions to oil and gas properties during the years ended December 31, 2004, 2003 and 2002 totaled \$615.9 million, \$688.1 million and \$614.7 million, respectively. The Company's 2004 and 2003 expenditures for additions to oil and gas properties were internally funded by \$1.1 billion and \$763.7 million, respectively, of net cash provided by operating activities. The Company's 2002 expenditures for additions to oil and gas properties were funded by \$332.2 million of net cash provided by operating activities, \$118.9 million of proceeds from the disposition of assets and a portion of the proceeds from the issuance of 11.5 million shares of the Company's common stock during April 2002.

The Company strives to maintain its indebtedness at reasonable levels in order to provide sufficient financial flexibility to take advantage of future opportunities. The Company's capital budget for 2005 is expected to range from \$900 million to \$950 million. The Company believes that net cash provided by operating activities during 2005 will be sufficient to fund the 2005 capital expenditures budget as well as reduce long-term debt to achieve a targeted debt to book capitalization of less than 35 percent and fund the Company's 2005 dividends. For additional information regarding the Company's plans for 2005, see "2005 Outlook and Activities" above.

Contractual obligations, including off-balance sheet obligations. The Company's contractual obligations include long-term debt, operating leases, drilling commitments, derivative obligations, other liabilities and, during 2005, the VPP obligations. 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, 2004, the material off-balance sheet arrangements and transactions that the Company has entered into include (i) $57.1 million of undrawn letters of credit, (ii) operating lease agreements, (iii) drilling commitments and (iv) 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.

The following table summarizes by period the payments due by the Company for contractual obligations estimated as of December 31, 2004:

	Payments Due by Year			
	2005	2006 and 2007	2008 and 2009	Thereafter
	(in thousands)			
Long-term debt (a)	$ 130,950	$ 832,075	$ 378,000	$ 1,151,579
Operating leases (b)	56,365	83,115	32,647	13,214
Drilling commitments (c)	10,468	7,957	-	-
Derivative obligations (d)	224,403	131,940	50,352	511
Other liabilities (e)	44,541	65,099	40,401	61,833
Transportation commitments (f)	58,622	119,697	118,929	287,021
	$ 525,349	$ 1,239,883	$ 620,329	$ 1,514,158

(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 J 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, 2004 for drilling rig services and well commitments.

(d) Derivative obligations represent net liabilities for oil and gas commodity derivatives that were valued as of December 31, 2004. These liabilities include $.2 million of current assets and $.9 million of long-term 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 K 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, J and M 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 J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's transportation commitments.

Capital resources. The Company's primary capital resources are net cash provided by operating activities, proceeds from financing activities and proceeds from sales of non-strategic assets. The Company expects that these resources will be sufficient to fund its capital commitments in 2005.

Operating activities. Net cash provided by operating activities during the years ended December 31, 2004, 2003 and 2002 were $1.1 billion, $763.7 million and $332.2 million, respectively. Net cash provided by operating activities in 2004 increased by $340.9 million, or 45 percent, as compared to that of 2003. The increase in 2004 was primarily due to increased production volumes and higher commodity prices as compared to 2003. Net cash provided by operating activities in 2003 increased by $431.4 million, or 130 percent, as compared to that of 2002. The increase in 2003 was primarily due to increased production volumes and higher commodity prices as compared to 2002.

Investing activities. Net cash used in investing activities during the years ended December 31, 2004, 2003 and 2002 were $1.5 billion, $662.3 million and $508.1 million, respectively. The $869.2 million increase in cash used in investing activities during 2004 as compared to 2003 was primarily due to $880.4 million paid, net of cash acquired, in conjunction with the Evergreen merger. The $154.2 million increase in cash used in investing activities during 2003 as compared to 2002 was primarily due to a $73.4 million increase in additions to oil and gas properties and an $83.2 million decrease in proceeds from disposition of assets. The cash proceeds from asset divestitures during 2003 were used to reduce outstanding indebtedness. See "Results of Operations", above, and Note O of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding asset divestitures.

Financing activities. Net cash provided by financing activities totaled $414.3 million and $170.9 million during the years ended December 31, 2004 and 2002, respectively. During the year ended December 31, 2003, financing activities used $91.7 million of net cash. The increase in net cash provided by financing activities in 2004 as compared to 2003 was primarily due to borrowings on the Company's lines of credit to finance the cash consideration paid in conjunction with the Evergreen merger offset by excess operating cash flows being used to repay borrowings on the Company's lines of credit and the $109.0 million paid in conjunction with the exchange of the Company's senior notes discussed below. 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, $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 2002, the Company's financing activities were comprised of $236.0 million of proceeds, netof issuance costs, from the sale of 11.5 million shares of the Company's common stock; $48.0 million of net borrowings of long-term debt; and $14.4 million of proceeds from the exercise of long-term incentive plan stock options and employee stock purchases, partially offset by $124.2 million of payments of other noncurrent liabilities and $3.3 million of payments for debt issuance costs.

Over the three-year period ended December 31, 2004, the Company has entered into financing transactions with the intent of reducing its cost of capital and increasing liquidity through the extension of debt maturities. During 2004, the Company accepted tenders to exchange $117.9 million, $275.1 million and $133.8 million in principal amount of its 8 1/4% senior notes due 2007, 9-5/8% senior notes due 2010 and 7.50% senior notes due 2012 (collectively, the "Old Notes"), respectively, for a like principal amount of New Notes and cash. The exchange of the Old Notes for the New Notes reduces the Company's future cash interest expense incurred and extended the associated debt maturities.

During September 2004, the Company entered into the 364-Day Credit Agreement that was used to finance the cash consideration associated with the Evergreen merger. Borrowings under the 364-Day Credit Agreement may, at the option of the Company, be designated to bear interest based on (a) a rate per annum equal to the higher of the prime rate announced from time to time by JPMorgan Chase Bank or the weighted average of the rates on overnight Federal funds transactions with members of the Federal Reserve System during the last preceding business day plus 50 basis point or (b) a base Eurodollar rate, substantially equal to LIBOR, plus a margin that is based on a grid of the Company's debt rating (75 basis points per annum at December 31, 2004). Effective February 4, 2005, the Company requested that commitments under the 364-Day Credit Agreement be reduced by $250 million to $650 million. Also in connection with the Evergreen merger, the Company assumed $100 million of 4.75% Senior Convertible Notes due 2021 (the "Convertible Notes") and $200 million of 5.875% Senior Subordinated Notes due 2012 (the "EVG 5.875% Notes"). During October 2004, the Company issued a Notice of Change of Control, Offer to Purchase, and the Consent Solicitation Statement (the "Notice") (i) notifying holders of the EVG 5.875% Notes of their right to require the Company to repurchase their EVG 5.875% Notes pursuant to the terms set forth in the Notice and (ii) soliciting consents to proposed amendments to the indenture governing the EVG 5.875%Notes (the "Consent Solicitation"). A majority of the holders of the EVG 5.875% Notes approved the Consent Solicitation which had the effect of (i) eliminating the subordination of the right of payment on the EVG 5.875% Notes, (ii) amending certain restrictive covenants applicable to the EVG 5.875% Notes so that they are the same as the restrictive covenants governing theCompany's other senior notes and (iii) amending provisions that suspend other restrictive covenants when the EVG 5.875% Notes receive certain investment grade ratings. Associated with the Offer to Purchase, the Company accepted tenders for and redeemed $5.5 million of the EVG 5.875% Notes. As a result of the Evergreen merger, the Convertible Notes are redeemable at any time 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 intends to exercise its rights under the indenture and redeem the Convertible Notes on such date for cash, common stock or a combination thereof. See Notes F and K of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplemental Data" and "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for more information about the Company's debt instruments and interest rate hedging activities.

The Company's future debt level is dependent primarily on net cash provided by operating activities, proceeds from financing activities and proceeds generated from asset dispositions. The Company believes it has substantial borrowing capacity, which has been further enhanced during 2005 by the use of the VPP net proceeds to reduce outstanding indebtedness, to meet any unanticipated cash requirements, and during low commodity price periods, the Company has the flexibility to increase borrowings and/or modify its capital spending to meet its contractual obligations and maintain its debt ratings. During 2005, $131.0 million of the Company's 8-7/8% senior notes due 2005 (the "8-7/8% Notes") will mature and the 364-Day Credit Agreement will have its first anniversary. The Company intends to initially utilize unused borrowing capacity under its 364-Day Credit Agreement to repay the 8-7/8% Notes and to transfer outstanding borrowings, if any, under the 364-Day Credit Agreement to the Company's Revolving Credit Agreement on its first anniversary. The Company also intends to refinance, under its Revolving Credit Agreement, the cash component of a redemption price associated with any redemption of the Convertible Notes prior to December 2006, should redemptions occur. Accordingly, the Company's Consolidated Balance Sheet does not reflect any current portion of long-term debt as of December 31, 2004.

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

Liquidity. The Company's principal source of short-term liquidity is its revolving lines of credit. Outstanding borrowings under the lines of credit totaled $828 million as of December 31, 2004. Including $49.3 million of undrawn and outstanding letters of credit under the lines of credit, the Company had $722.7 million of unused borrowing capacity as of December 31, 2004.

Book capitalization and current ratio. The Company's book capitalization at December 31, 2004 was $5.2 billion, consisting of debt of $2.4 billion and stockholders' equity of $2.8 billion. Consequently, the Company's debt to book capitalization decreased to 45.7 percent at December 31, 2004 from 46.9 percent at December 31, 2003. As more fully discussed in "2005 Outlook and Activities" above, the Company has targeted a range for debt to book capitalization of less than 35 percent by the end of 2005. The Company's ratio of current assets to current liabilities was .57 at December 31, 2004 as compared to .48 at December 31, 2003. The improvement in the Company's ratio of current assets to current liabilities was primarily due to increases in oil and gas receivables due to higher commodity prices.

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") and are subject to regular reviews. The Company's debt is currently rated BBB- with a negative outlook by S&P and Baa3 with a negative outlook by Moody's, both of which are investment-grade ratings. 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. There are no "ratings triggers" in any of the Company's contractual obligations that would accelerate the related scheduled maturities should the Company's ratings fall below certain levels. If the Company were to be downgraded by either S&P or Moody's, it could negatively impact the interest rate and fees on existing indebtedness and the Company's ability to obtain additional financing or the interest rate and fees associated with additional financing.

New Accounting Pronouncement

On December 16, 2004, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 123 (revised 2004), "Share-Based Payment" ("SFAS 123(R)"), which is a revision of Statement of Financial Accounting Standards 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 Statement of Financial Accounting Standards 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 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 July 1, 2005 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 effective date and based on the requirements of SFAS 123 for all awards granted to employees prior to the adoption 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 has elected to adopt the provisions of SFAS 123(R) on July 1, 2005 using the modified prospective method.

As permitted by SFAS 123, the Company currently accounts for share-based payments to employees using the intrinsic value method prescribed by APB 25 and related interpretations. As such, the Company generally does not recognize compensation expenses associated with employee stock options. Accordingly, the adoption of SFAS 123(R)'s fair value method could have a significant impact on the Company's future result of operations, although it will have no impact on the Company's overall 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 net income and earnings per share 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 the Company's outstanding restricted stock awards. The Company estimates that the adoption of SFAS 123(R), based on the outstanding unvested stock options at December 31, 2004, will result in future compensation charges to general and administrative expenses of approximately $1.8 million during the period from July 1, 2005 through December 31, 2005, and approximately $1.1 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 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the ESPP.

SFAS 123(R) also requires the tax benefits in excess of recognized compensation expenses to be reported as a financing cash flow, rather than as an operating cash flow as required under current literature. This requirement may serve to reduce the Company's future cash provided by operating activities and increase future cash provided by financing activities, to the extent of associated tax benefits that may be realized in the future. While the Company cannot estimate what those amounts will be in the future (because they depend on, among other things, when employees exercise stock options), the amount of operating cash flows recognized in prior periods for such excess tax deductions were $6.6 million and $14.7 million during the years ended December 31, 2004 and 2003, respectively. The Company did not recognize any such tax benefits during 2002.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The following quantitative and qualitative information is provided about financial instruments to which the Company was a party as of December 31, 2004 and 2003, and from which the Company may incur future gains or losses from changes in market interest rates, foreign exchange rates or commodity prices. Although certain derivative contracts that the Company was 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 the year ended December 31, 2004. During 2004, the Company was a party to commodity and interest rate swap contracts and commodity collar contracts. See Note K 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 2004:

	Derivative Contract Assets (Liabilities)		
	Commodity	Interest Rate	Total
		(in thousands)	
Fair value of contracts outstanding as of December 31, 2003	$ (201,422)	$ -	$ (201,422)
Fair value of Evergreen contracts assumed	(52,115)	-	(52,115)
Changes in contract fair values (a)	(444,125)	(10,638)	(454,763)
Contract maturities	292,475	(2,167)	290,308
Contract terminations	(1,359)	12,805	11,446
Fair value of contracts outstanding as of December 31, 2004	$ (406,546)	$ -	$ (406,546)

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

Quantitative Disclosures

Interest rate sensitivity. The following tables provide information about other financial instruments that the Company was a party to as of December 31, 2004 and 2003 and that are or 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, 2004 and 2003. 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 January 31, 2005.

Interest Rate Sensitivity
Debt Obligations as of December 31, 2004

	Year Ending December 31,							Liability Fair Value December 2004
	2005	2006	2007	2008	2009	Thereafter	Total	
				(in thousands, except interest rates)				
Total Debt:								
Fixed rate principal maturities (a)	$130,950	$ -	$ 32,075	$350,000	$ -	$1,151,579	$1,664,604	$(1,846,11
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	$ (828,00
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.

Interest Rate Sensitivity
Debt Obligations as of December 31, 2003

	Year Ending December 31,							Liability Fair Value at December 31,
	2004	2005	2006	2007	2008	Thereafter	Total	2003
	(in thousands, except interest rates)							
Total Debt:								
Fixed rate principal maturities (a)	$ -	$130,950	$ -	$150,000	$350,000	$ 739,169	$1,370,119	$(1,549,026)
Weighted average interest rate (%)	7.93	7.86	7.83	7.81	8.34	8.37		
Variable rate maturities	$ -	$ -	$ -	$ -	$160,000	$ -	$ 160,000	$ (160,000)
Average interest rate (%)	2.87	4.28	5.27	5.91	6.28	-		

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

Foreign exchange rate sensitivity. There were no outstanding foreign exchange rate hedge derivatives at December 31, 2004 and 2003.

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, 2004 and 2003. As of December 31, 2004 and 2003, 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 K of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for a description of the accounting procedures followed by the Company relative to hedge derivative financial instruments and for specific information regarding the terms of the Company's derivative financial instruments that are sensitive to changes in oil and gas prices.

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

	Year Ending December 31,								Liability Fair Value at December 31,
	2005	2006	2007	2008	2009	2010	2011	2012	2004
									(in thousands)
Oil Hedge Derivatives (a):									
Average daily notional Bbl volumes:									
Swap contracts (b)	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 (c)	$ 48.58	$ 45.26	$ 43.08	$ 41.01	$ 40.36	$ 39.91	$ 39.71	$ 39.51	

(a) See Note K 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, 2004, the Company conveyed to the purchaser of the Spraberry VPP 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.

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

Oil Price Sensitivity
Derivative Financial Instruments as of December 31, 2003

	Year Ending December 31,					Liability Fair Value at December 31,
	2004	2005	2006	2007	2008	2003
						(in thousands)
Oil Hedge Derivatives:						
Average daily notional Bbl volumes:						
Swap contracts	18,973	17,000	5,000	1,000	5,000	$ (50,240)
Weighted average fixed price per Bbl .	$ 25.84	$ 24.93	$ 26.19	$ 26.00	$ 26.09	
Average forward NYMEX oil prices (a)	$ 30.12	$ 28.03	$ 27.09	$ 26.55	$ 26.60	

(a) The average forward NYMEX oil prices are based on January 30, 2004 market quotes.

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

	Year Ending December 31,					Liability Fair Value at December 31,
	2005	2006	2007	2008	2009	2004
						(in thousands)
Gas Hedge Derivatives (a):						
Average daily notional MMBtu volumes (b):						
Swap contracts (c)	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 (d)	$ 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) See Note K 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, 2004, the Company conveyed to the purchaser of the Hugoton VPP 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.

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

Gas Price Sensitivity
Derivative Financial Instruments as of December 31, 2003

	Year Ending December 31,				Liability Fair Value at December 31,
	2004	2005	2006	2007	2003
					(in thousands)
Gas Hedge Derivatives (a):					
Average daily notional MMBtu volumes:					
Swap contracts	283,962	60,000	70,000	20,000	$ (151,182)
Weighted average fixed price per MMBtu	$ 4.16	$ 4.24	$ 4.16	$ 3.51	
Average forward NYMEX gas prices (b)	$ 4.66	$ 5.04	$ 4.74	$ 4.60	

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

(b) The average forward NYMEX gas prices are based on January 30, 2004 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 Company's board of directors. In accordance with those policies and guidelines, the Company's executive management determines the appropriate timing and extent of hedge transactions.

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, seven and five percent of the Company's 2004 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 South Africa, Tunisia, Gabon and Equatorial Guinea. 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, incurring repeated significant fiscal deficits that by the end of 2001 resulted in the accumulation of $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 placeda 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, 2004, the peso-to-U.S. dollar exchange rate was 2.98:1.

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 barrels as WTI prices per barrel increase from less than $32.00 to $45.00 and above.

During 2002 and 2003, the Company exported approximately 29 percent and five percent, respectively, of its Argentine oil production. Associated therewith, the Company incurred oil export taxes of $2.2 million and $1.2 million for 2002 and 2003, respectively. During 2004, 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 2004 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.

- **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 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 theend 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 $.48, $.56 and $.66 in 2002, 2003 and 2004, 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. Recently, 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 rise from a current 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 been allowed for in the current decree. 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, 2004, 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, 2004.

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 and subsidiaries (the "Company") as of December 31, 2004 and 2003, and the related consolidated statements of operations, stockholders' equity, cash flows and comprehensive income (loss) for each of the three years in the period ended December 31, 2004. 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 and subsidiaries at December 31, 2004 and 2003, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2004, 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, 2004, 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 17, 2005 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 17, 2005

PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED BALANCE SHEETS
(in thousands, except share data)

	December 31, 2004	December 31, 2003
ASSETS		
Current assets:		
Cash and cash equivalents	$ 7,257	$ 19,299
Accounts receivable:		
Trade, net of allowance for doubtful accounts of $7,348 and $4,727 as of December 31, 2004 and 2003, respectively	207,696	111,033
Due from affiliates	2,583	447
Inventories	40,332	17,509
Prepaid expenses	10,822	11,083
Deferred income taxes	33,980	40,514
Other current assets:		
Derivatives	209	423
Other, net of allowance for doubtful accounts of $4,486 as of December 31, 2004 and 2003	9,320	4,807
Total current assets	312,199	205,115
Property, plant and equipment, at cost:		
Oil and gas properties, using the successful efforts method of accounting:		
Proved properties	7,654,181	4,983,558
Unproved properties	470,435	179,825
Accumulated depletion, depreciation and amortization	(2,243,549)	(1,676,136)
Total property, plant and equipment	5,881,067	3,487,247
Deferred income taxes	2,963	192,344
Goodwill	315,880	-
Other property and equipment, net	78,696	28,080
Other assets:		
Derivatives	-	209
Other, net of allowance for doubtful accounts of $92 as of December 31, 2004 and 2003	56,436	38,577
	$ 6,647,241	$ 3,951,572
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 205,153	$ 177,614
Due to affiliates	10,898	8,804
Interest payable	45,735	37,034
Income taxes payable	13,520	5,928
Other current liabilities:		
Derivatives	224,612	161,574
Other	44,541	38,798
Total current liabilities	544,459	429,752
Long-term debt	2,385,950	1,555,461
Derivatives	182,803	48,825
Deferred income taxes	526,189	12,121
Other liabilities and minority interests	176,060	145,641
Stockholders' equity:		
Common stock, $.01 par value; 500,000,000 shares authorized; 145,644,828 and 119,665,784 shares issued at December 31, 2004 and 2003, respectively	1,456	1,197
Additional paid-in capital	3,705,286	2,734,403
Treasury stock, at cost; 813,166 and 378,012 shares at December 31, 2004 and 2003, respectively	(27,793)	(5,385)
Deferred compensation	(22,558)	(9,933)
Accumulated deficit	(634,146)	(887,848)
Accumulated other comprehensive income (loss):		
Net deferred hedge losses, net of tax	(241,350)	(104,130)
Cumulative translation adjustment	50,885	31,468
Total stockholders' equity	2,831,780	1,759,772
Commitments and contingencies		
	$ 6,647,241	$ 3,951,572

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,		
	2004	2003	2002
Revenues and other income:			
Oil and gas	$ 1,832,663	$ 1,273,871	$ 694,355
Interest and other	14,074	12,292	11,222
Gain on disposition of assets, net	39	1,256	4,432
	1,846,776	1,287,419	710,009
Costs and expenses:			
Oil and gas production	345,504	254,750	192,145
Depletion, depreciation and amortization	574,874	390,840	216,375
Impairment of oil and gas properties	39,684	-	-
Exploration and abandonments	181,689	132,760	85,894
General and administrative	80,528	60,545	48,402
Accretion of discount on asset retirement obligations	8,210	5,040	-
Interest	103,387	91,388	95,815
Other	33,687	21,320	39,602
	1,367,563	956,643	678,233
Income before income taxes and cumulative effect of change in accounting principle	479,213	330,776	31,776
Income tax benefit (provision)	(166,359)	64,403	(5,063)
Income before cumulative effect of change in accounting principle	312,854	395,179	26,713
Cumulative effect of change in accounting principle, net of tax	-	15,413	-
Net income	$ 312,854	$ 410,592	$ 26,713
Basic earnings per share:			
Income before cumulative effect of change in accounting principle	$ 2.50	$ 3.37	$ .24
Cumulative effect of change in accounting principle, net of tax	-	.13	-
Net income	$ 2.50	$ 3.50	$ .24
Diluted earnings per share:			
Income before cumulative effect of change in accounting principle	$ 2.46	$ 3.33	$ .23
Cumulative effect of change in accounting principle, net of tax	-	.13	-
Net income	$ 2.46	$ 3.46	$ .23
Weighted average shares outstanding:			
Basic	125,156	117,185	112,542
Diluted	127,488	118,513	114,288

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, 2002	$ 1,074	$ 2,462,272	$ (48,002)	$ -	$ (1,323,343)	$ 201,046	$ (7,658)	$ 1,285,389
Issuance of common stock	115	235,885	-	-	-	-	-	236,000
Adjustment to common stock issued for 2001 partnership acquisitions	-	(175)	-	-	-	-	-	(175)
Exercise of long-term incentive plan stock options and employee stock purchases	-	416	15,783	-	(1,810)	-	-	14,389
Deferred compensation:								
Compensation deferred	7	16,169	-	(16,176)	-	-	-	-
Deferred compensation included in net income	-	-	-	1,884	-	-	-	1,884
Net income	-	-	-	-	26,713	-	-	26,713
Other comprehensive income (loss):								
Net deferred hedge gains (losses), net of tax:								
Net deferred hedge losses	-	-	-	-	-	(181,628)	-	(181,628)
Net hedge gains included in net income	-	-	-	-	-	(12,424)	-	(12,424)
Tax benefits related to net hedge losses	-	-	-	-	-	2,561	-	2,561
Translation adjustment	-	-	-	-	-	-	2,188	2,188
Balance as of December 31, 2002	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

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,		
	2004	2003	2002
Cash flows from operating activities:			
Net income	$ 312,854	$ 410,592	$ 26,713
Adjustments to reconcile net income to net cash provided by operating activities:			
Depletion, depreciation and amortization	574,874	390,840	216,375
Impairment of oil and gas properties	39,684	-	-
Exploration expenses, including dry holes	146,833	97,690	64,617
Deferred income taxes	141,072	(75,588)	2,788
Gain on disposition of assets, net	(39)	(1,256)	(4,432)
Accretion of discount on asset retirement obligations	8,210	5,040	-
Noncash interest expense	(12,208)	(20,610)	(5,809)
Commodity hedge related amortization	(45,102)	(71,816)	26,490
Cumulative effect of change in accounting principle, net of tax	-	(15,413)	-
Amortization of stock-based compensation	12,503	5,429	1,884
Other noncash items	16,913	4,966	29,763
Change in operating assets and liabilities, net of effects from acquisitions:			
Accounts receivable, net	(73,376)	(10,983)	(23,922)
Inventories	(14,025)	(7,734)	3,023
Prepaid expenses	974	(5,598)	2,330
Other current assets, net	262	(602)	(4,166)
Accounts payable	250	58,603	(342)
Interest payable	5,533	(424)	48
Income taxes payable	3,372	5,928	(530)
Other current liabilities	(14,037)	(5,385)	(2,585)
Net cash provided by operating activities	1,104,547	763,679	332,245
Cash flows from investing activities:			
Payments for acquisition, net of cash acquired	(880,365)	-	-
Proceeds from disposition of assets	1,709	35,698	118,850
Additions to oil and gas properties	(615,895)	(688,133)	(614,698)
Other property additions, net	(36,970)	(9,865)	(12,283)
Net cash used in investing activities	(1,531,521)	(662,300)	(508,131)
Cash flows from financing activities:			
Borrowings under long-term debt	1,157,903	264,725	529,805
Principal payments on long-term debt	(604,475)	(370,262)	(481,783)
Common stock issuance proceeds, net of issuance costs	-	-	236,000
Payment of other liabilities	(54,252)	(14,055)	(124,245)
Exercise of long-term incentive plan stock options and employee stock purchases	35,068	33,020	14,389
Purchase of treasury stock	(92,256)	(2,349)	-
Payment of financing fees	(1,173)	(2,799)	(3,293)
Dividends paid	(26,557)	-	-
Net cash provided by (used in) financing activities	414,258	(91,720)	170,873
Net increase (decrease) in cash and cash equivalents	(12,716)	9,659	(5,013)
Effect of exchange rate changes on cash and cash equivalents	674	1,150	(831)
Cash and cash equivalents, beginning of year	19,299	8,490	14,334
Cash and cash equivalents, end of year	$ 7,257	$ 19,299	$ 8,490

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

PIONEER NATURAL RESOURCES COMPANY

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

	Year ended December 31,		
	2004	2003	2002
Net income	$ 312,854	$ 410,592	$ 26,713
Other comprehensive loss:			
Net deferred hedge losses, net of tax:			
Net deferred hedge losses	(443,318)	(282,165)	(181,628)
Net hedge losses (gains) included in net income	232,758	117,416	(12,424)
Tax benefits related to net hedge losses	73,340	51,064	2,561
Translation adjustment	19,417	36,938	2,188
Other comprehensive loss	(117,803)	(76,747)	(189,303)
Comprehensive income (loss)	$ 195,051	$ 333,845	$ (162,590)

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, Gabon, South Africa and Tunisia.

On September 28, 2004, the Company completed a merger with Evergreen Resources, Inc. ("Evergreen"), as set forth in the Agreement and Plan of Merger dated May 3, 2004 (the "Merger Agreement"), 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 No. 141, "Business Combinations" ("SFAS 141"), the merger has been accounted for as a purchase of Evergreen by Pioneer. As a result, the historical financial statements for the Company are those of Pioneer, and the Company's Consolidated Balance Sheets present the addition of Evergreen's assets and liabilities as of September 28, 2004. 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, and the Company's interest in the affiliated oil and gas partnerships for which it serves as general partner through certain of its wholly-owned subsidiaries. The Company proportionately consolidates less than 100 percent-owned affiliate partnerships involved in oil and gas producing activities in accordance with industry practice. The Company owns less than a 20 percent interest in the oil and gas partnerships that it proportionately consolidates. All material intercompany balances and transactions have been eliminated.

Minority interests. As of December 31, 2004, other liabilities and minority interests in the Company's Consolidated Balance Sheet includes $8.7 million of minority interests attributable to outside ownership interests in certain entities acquired in the Evergreen merger. The minority interest in these subsidiaries' net income for the three months ended December 31, 2004 was $.9 million and is included in other expense in the Company's Consolidated Statement of Operations.

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 only a short period of time; 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 revenue, 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, 2004 or 2003.

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, 2004 or 2003.

Use of estimates in the preparation of financial statements. Preparation of the accompanying consolidated financial statements in conformity with generally accepted accounting principles in the United States ("GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Depletion of oil and gas properties 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, 2004 and 2003, the Company used exchange rates of 2.98 pesos to $1 and 2.93 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, 2004, 2003 and 2002 resulted in a gain of $.2 million and charges of $.3 million and $6.9 million, respectively.

As a result of certain Argentine stability laws and regulations enacted since the devaluation of the Argentine peso which 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 estimates of future commodity prices and operating costs, the Company believes that the future cash flows from its oil and gas assets will be sufficient to fully recover its proved property basis. The Company also plans to continue its exploration efforts on all of its remaining unproved acreage. Based upon the Company's improved economic outlook for Argentina, the Company has significantly 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.

Adoption of SFAS 143. On January 1, 2003, the Company adopted the provisions of Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" ("SFAS 143"). SFAS 143 amended Statement of Financial Accounting Standards No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies" ("SFAS 19") to require that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. Under the provisions of SFAS 143, asset retirement obligations are capitalized as part of the carrying value of the long-lived asset.

The adoption of SFAS 143 resulted in a January 1, 2003 cumulative effect adjustment to record a 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 M 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 years ended December 31, 2003 and 2002 as if the Company had adopted the provisions of SFAS 143 on January 1, 2002.

	Year ended December 31,	
	2003	2002
	(in thousands, except per share amounts)	
Net income, as reported	$ 410,592	$ 26,713
Pro forma adjustments to reflect retroactive adoption of SFAS 143	(15,413)	4,743
Pro forma net income	$ 395,179	$ 31,456
Net income per share:		
Basic - as reported	$ 3.50	$ .24
Basic - pro forma	$ 3.37	$ .28
Diluted - as reported	$ 3.46	$ .23
Diluted - pro forma	$ 3.33	$ .28

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

Inventories - equipment. Lease and well equipment inventory to be used in future joint operations activities are carried at the lower of cost or market, on a first-in, first-out basis. Total lease and well equipment inventory was $37.9 million and $15.3 million as of December 31, 2004 and 2003, respectively, and is net of valuation reserve allowances of $.4 million and $.6 million as of December 31, 2004 and 2003, respectively.

Inventories - commodities. Commodities are carried at the lower of average cost or market. When sold from inventory, commodities are removed on a first-in, first-out basis. Total commodity inventory was $2.4 million and $2.2 million as of December 31, 2004 and 2003, respectively.

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 if the required capital expenditure is made.
(ii) Drilling of the additional exploratory wells is under way or firmly planned for the near future.

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 projects 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 costs.

The Company owns interests in 11 natural gas processing plants and five treating facilities. The Company operates seven of the plants and all five treating facilities. The Company's ownership in the natural gas processing plants and treating facilities is primarily to accommodate handling the Company's gas production and thus are considered a component of the capital and operating costs of the respective fields that they service. To the extent that there is excess capacity at a plant or treating facility, the Company attempts to process third party gas volumes for a fee to keep the plant or treating facility at capacity. All revenues and expenses derived from third party gas volumes processed through the plants and treating facilities are reported as components of oil and gas production costs. The third party revenues generated from the plant and treating facilities for the three years ended December 31, 2004, 2003 and 2002 were $45.9 million, $39.5 million and $28.4 million, respectively. The third party expenses attributable to the plants and treating facilities for the same respective periods were $11.9 million, $11.3 million and $9.3 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 Statement of Financial Accounting Standards 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 is described in Note C, the Company recorded $324.8 million of goodwill associated with the Evergreen merger. The goodwill was recorded to the Company's United States reporting unit and will be subject to change during the twelve-month period following the merger if the settlement values of monetary assets acquired and liabilities assumed in the merger differ from their estimated values as of September 28, 2004. In accordance with Emerging Issues Task Force ("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 reduced goodwill by $9.0 million during the fourth quarter of 2004 for tax benefits associated with the exercise of fully-vested stock options assumed in conjunction with the Evergreen merger to the extent that the stock-based compensation expense reported for tax purposes did not exceed the fair value of the awards recognized as part of the total purchase price. In accordance with Statement of Financial Accounting Standards 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.

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

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

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

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

The Company had no oil or natural gas liquid ("NGL") entitlement assets or liabilities as of December 31, 2004 or 2003. The following table presents the Company's gas entitlement assets and liabilities and their associated volumes as of December 31, 2004 and 2003:

	December 31,			
	2004		2003	
	Amount	MMcf	Amount	MMcf
	($ in millions)			
Entitlement assets	$ 10.4	3,842	$ 10.5	3,929
Entitlement liabilities	$ 14.7	11,859	$ 15.8	14,793

Derivatives and hedging. The Company follows the provisions of Statement of Financial Accounting Standards 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 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 K for a description of the specific types of derivative transactions in which the Company participates.

Stock-based compensation. The Company has a long-term incentive plan (the "Long-Term Incentive Plan") under which the Company grants stock-based compensation. The Long-Term Incentive Plan is described more fully in Note 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, 2004, 2003 and 2002, 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 pronouncement" below for information regarding the Company's adoption of Statement of Financial Accounting Standards No. 123 (revised 2004), "Share-Based Payment" ("SFAS 123(R)") on July 1, 2005.

The following table illustrates the pro forma effect on net income and earnings per share as if the Company had applied the fair value recognition provisions of Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation" ("SFAS 123"), to stock-based compensation during the years ended December 31, 2004, 2003 and 2002:

	Year ended December 31,		
	2004	2003	2002
	(in thousands, except per share amounts)		
Net income, as reported	$ 312,854	$ 410,592	$ 26,713
Plus: Stock-based compensation expense included in net income for all awards, net of tax (a)	7,939	3,447	1,884
Deduct: Stock-based compensation expense determined under fair value based method for all awards, net of tax (a)	(13,985)	(11,429)	(11,691)
Pro forma net income	$ 306,808	$ 402,610	$ 16,906
Net income per share:			
Basic - as reported	$ 2.50	$ 3.50	$ .24
Basic - pro forma	$ 2.45	$ 3.44	$ .15
Diluted - as reported	$ 2.46	$ 3.46	$ .23
Diluted - pro forma	$ 2.41	$ 3.40	$ .15

(a) For the years ended December 31, 2004 and 2003, stock-based compensation expense included in net income is net of tax benefits of $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, 2004 and 2003 is net of tax benefits of $8.0 million and $6.6 million, respectively. No tax benefits were recognized for the stock-based compensation expense amounts during the year ended December 31, 2002. See Note Q 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, 2004, 2003 and 2002:

	December 31,		
	2004	2003	2002
U.S. Dollar from Canadian Dollar - Balance Sheets	.8320	.7710	.6362
U.S. Dollar from Canadian Dollar - Statements of Operations	.7699	.7161	.6371

Reclassifications. Certain reclassifications have been made to the 2003 and 2002 amounts in order to conform with the 2004 presentation. Specifically, the Company reduced oil and gas revenues and production costs by $40.6 million and $23.6 million for the years ended December 31, 2003 and 2002, respectively, to conform with its current treatment of field fuel. During 2004, the Company changed its treatment of field fuel, which is gas consumed to operate field equipment, to exclude the field fuel gas from oil and gas revenues and production costs. The Company also increased oil and gas revenues and production costs by $15.8 million and $16.2 million for the years ended December 31, 2003 and 2002, respectively, to conform with its current treatment of Canadian gas transportation costs. During 2004, the Company changed its treatment of Canadian gas transportation costs to include these costs as a component of oil and gas production costs. In prior years, transportation costs were recorded as a reduction to oil and gas revenues.

New accounting pronouncement. On December 16, 2004, the Financial Accounting Standards Board ("FASB") issued SFAS 123(R), which is a revision of SFAS 123. SFAS 123(R) supersedes APB 25 and amends Statement of Accounting Standards 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 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 July 1, 2005 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 has elected to adopt the provisions of SFAS 123(R) on July 1, 2005 using the modified prospective method.

As permitted by SFAS 123, the Company currently accounts for share-based payments to employees using the intrinsic value method prescribed by APB 25 and related interpretations. As such, the Company generally does not recognize compensation expenses associated with employee stock options. Accordingly, the adoption of SFAS 123(R)'s fair value method could have a significant impact on the Company's future result of operations, although it will have no impact on the Company's overall 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 net income and earnings per share disclosures above. The adoption of SFAS 123(R) will have no effect on the Company's unvested outstanding restricted stock awards. The Company estimates that the adoption of SFAS 123(R), based on the outstanding unvested stock options at December 31, 2004, will result in future compensation charges to general and administrative expenses of approximately $1.8 million during the period from July 1, 2005 throughDecember 31, 2005, and approximately $1.1 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 the tax benefits in excess of recognized compensation expenses to be reported as a financing cash flow, rather than as an operating cash flow as required under current literature. This requirement may serve to reduce the Company's future cash provided by operating activities and increase future cash provided by financing activities, to the extent of associated tax benefits that may be realized in the future. While the Company cannot estimate what those amounts will be in the future (because they depend on, among other things, when employees exercise stock options), the amount of operating cash flows recognized in prior periods for such excess tax deductions were $6.6 million and $14.7 million during the years ended December 31, 2004 and 2003, respectively. The Company did not recognize any such tax benefits during 2002.

NOTE C. Acquisitions

Evergreen Merger. On September 28, 2004, Pioneer completed its merger with Evergreen withPioneer being the surviving corporation for accounting purposes. The transaction was accounted for as a purchase of Evergreen by Pioneer in accordance with SFAS 141. 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, net of$12.1 million of acquired cash, to the Evergreen shareholders at closing. The value of each share of Pioneer was based on the five-day average closing price of Pioneer's common stock surrounding the May 3, 2004 announcement date of the merger, which equaled $32.578 per share. In addition, as consideration for Evergreen's Kansas assets, which were sold to a third party for net proceeds of $20.9 million on September 27, 2004, Evergreen stockholders received an additional cash payment equal to $.48 per Evergreen common share. The cash consideration paid in the merger was financed through borrowings on the Company's new $900 million 364-day senior unsecured revolving credit facility (the "364-Day Credit Agreement"). During the fourth quarter of 2004, the Company paid $29.3 million of transaction costs associated with the merger that were accrued but unpaid on September 28, 2004.

The following table represents the allocation of the total purchase price of Evergreen to the acquired assets and assumed liabilities based upon the fair values assigned to each of the significant assets acquired and liabilities assumed. The fair value of the proved properties was based on the Company's estimate of the present value of the acquired proved reserves. Likewise, the fair value of the unproved properties was estimated by risk-weighting the present value of the acquired probable reserves. Any future adjustments to the allocation of the purchase price are not anticipated to be material to the Company's financial statements.

	(in thousands)
Fair value of Evergreen's net assets:	
Net working capital, including cash of $12.1 million	$ (44,956)
Proved oil and gas properties	2,235,935
Unproved oil and gas properties	274,917
Other assets	40,506
Goodwill	324,835
Long-term debt	(305,500)
Deferred income tax liabilities	(657,035)
Other noncurrent liabilities, including minority interest in subsidiaries	(33,320)
Deferred compensation associated with unvested restricted stock awards	6,001
Additional paid-in capital (excess fair value of convertible debt attributable to equity conversion rights)	(63,500)
	$ 1,777,883
Consideration paid for Evergreen's net assets:	
Pioneer common stock issued	$ 826,514
Cash consideration paid	863,193
Aggregate purchase consideration issued to Evergreen stockholders	1,689,707
Plus:	
Pioneer common stock issuable to holders of unvested restricted stock awards upon lapse of restrictions	6,568
Proceeds from the sale of Kansas properties to be paid to holders of unvested restricted stock awards upon lapse of restrictions	83
Exchange of Evergreen employee stock options	51,006
Estimated direct merger costs incurred	30,519
Total purchase price	$ 1,777,883

Evergreen was a publicly-traded independent oil and gas company primarily engaged in the production, development, exploration and acquisition of North American unconventional gas. Evergreen was based in Denver, Colorado and was one of the leading developers of coal bed methane reserves in the United States. Evergreen's operations were principally focused on developing and expanding its coal bed methane 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 as a result of Evergreen's acquisition of Carbon Energy Corporation on October 29, 2003 (the "Carbon acquisition").

The merger with Evergreen provided an opportunity for the Company to rebalance its portfolio of long-lived foundation assets by adding Evergreen's long-lived onshore producing asset base and significant low-risk development and extension drilling opportunities. Additionally, the Company's decision to complete the merger was positively impacted by the compatible technical and corporate cultures of Pioneer and Evergreen, Evergreen's substantial acreage position in key growth basins of the United States Rockies area and the opportunity to leverage Evergreen's technical expertise in the area of coal bed methane operations, which management believes could have further application in other areas of the United States. These strategic opportunities were among the factors considered when the Company determined its offering price for Evergreen.

Included in working capital and other assets in the table above is $6.4 million of intangible assets attributable to noncompete agreements executed with three former executive officers of Evergreen, including Mr. Mark Sexton, a director of the Company since the merger and formerly Evergreen's President, Chief Executive Officer and Chairman of the board of directors. The noncompete agreements are being amortized on a straight-line basis as charges to the Company's net income during the two-year period ending September 28, 2006. Additionally, the Company recorded $324.8 million of goodwill associated with the Evergreen merger, which amount represents the excess of the purchase consideration over the net fair value of the identifiable net assets acquired. Based on the expected strategic benefits of the Evergreen merger that are expected to be realized on a reporting unit basis, the goodwill has been recorded as an asset of the Company's United States reporting unit. The goodwill is not expected to be deductible for income tax purposes. The fair values of the monetary assets acquired and liabilities assumed is being monitored during the twelve-month period ending September 28, 2005 and will be adjusted if their settlement values differ from the estimated fair values assigned to them as of September 28, 2004. Forthcoming adjustments of the fair values assigned to acquired monetary assets and liabilities, if required, will change the value assigned to goodwill in the merger.

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 and the Carbon acquisition had each occurred on January 1, 2003. The unaudited pro forma combined condensed financial data have been included for comparative purposes only and are not necessarily indicative of the results that might have occurred had the transactionstaken place as of the dates indicated and are not intended to be a projection of future results.

	Year ended December 31,	
	2004	2003
	(in thousands, except per share amounts)	
Revenues	$ 2,029,841	$ 1,547,752
Income before cumulative effect of change in accounting principle	$ 326,132	$ 414,925
Cumulative effect of change in accounting principle, net of tax	-	15,036
Net income	$ 326,132	$ 429,961
Basic earnings per share:		
Income before cumulative effect of change in accounting principle	$ 2.26	$ 2.91
Cumulative effect of change in accounting principle, net of tax	-	.11
Net income	$ 2.26	$ 3.02
Diluted earnings per share:		
Income before cumulative effect of change in accounting principle	$ 2.20	$ 2.83
Cumulative effect of change in accounting principle, net of tax	-	.10
Net income	$ 2.20	$ 2.93

Falcon acquisitions. During the year ended December 31, 2002, the Company purchased, through two transactions, an additional 30 percent working interest in the Falcon field development and a 25 percent working interest in associated acreage in the deepwater Gulf of Mexico for a combined purchase price of $61.1 million. As a result of these transactions, the Company owned a 75 percent working interest in and operated the Falcon field development and related exploration blocks at December 31, 2002. On March 28, 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.

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

Other acquisitions. During 2004, the Company spent $20.2 million to acquire various additional working interests in the Spraberry field. The Company also spent $16.8 million to acquire acreage in Alaska and $10.5 million in Canada to acquire producing property and undeveloped acreage in southern Alberta. In addition to these acquisitions, the Company spent $43.2 million to acquire producing properties in the United States and unproved properties in the Gulf of Mexico, Canada and Africa. During 2003, in addition to the incremental 25 percent working interest acquired in the Falcon area, the Company spent $30.6 million to acquire producing properties in the Spraberry field and unproved properties in Alaska, the Gulf of Mexico, Argentina, Canada and Tunisia. During 2002, in addition to the Falcon and West Panhandle acquisitions referred to above, the Company spent $25.5 million to acquire additional unproved acreage in the United States, including 34 Gulf of Mexico shelf blocks, six deepwater Gulf of Mexico blocks, a 70 percent working interest in ten state leases on Alaska's North Slope and property interests in other areas of the United States. Also during 2002, the Company acquired unproved and proved oil and gas property interests in Canada for $2.3 million and $.5 million, respectively, and $1.8 million of additional unproved property interests in Tunisia.

NOTE D. Exploratory Well Costs

The Company capitalizes exploratory well costs until a decision is made that the well has found proved reserves or that it is impaired, in which case 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, 2004, 2003 and 2002:

	Year ended December 31,		
	2004	2003	2002
		(in thousands)	
Beginning of year	$ 108,986	$ 71,500	$ 52,975
Additions to exploratory well costs pending the determination of proved reserves	156,937	216,352	89,128
Reclassifications to proved reserves	(56,639)	(117,966)	(34,072)
Exploratory well costs charged to expense	(82,812)	(60,900)	(36,531)
End of year	$ 126,472	$ 108,986	$ 71,500

The following table provides an aging as of December 31, 2004, 2003 and 2002 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,		
	2004	2003	2002
	(in thousands, except well counts)		
Capitalized exploratory well costs that have been capitalized for a period of one year or less	$ 35,046	$ 75,120	$ 46,020
Capitalized exploratory well costs that have been capitalized for a period greater than one year	91,426	33,866	25,480
	$ 126,472	$ 108,986	$ 71,500
Number of wells that have exploratory well costs that have been capitalized for a period greater than one year	10	3	4

The following table provides the capitalized exploratory well costs of significant discrete exploration prospects that have been suspended for more than one year as of December 31, 2004, 2003 and 2002:

	December 31,		
	2004	2003	2002
		(in thousands)	
United States:			
Ozona Deep	$ 19,462	$ 19,003	$ -
Alaska - Oooguruk	47,083	-	-
Canada:			
Other	1,214	-	238
Africa:			
South African gas project	14,895	14,863	14,790
Tunisia - Anaguid	8,772	-	-
Gabon	-	-	10,452
Total	$ 91,426	$ 33,866	$ 25,480

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. Pioneer and the operator of Ozona Deep have been diligently engaging potential counterparties to enter into a PHA to bring future production from the discovery to their platform. The Company anticipates entering into a PHA and drilling an appraisal well during 2005.

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 costs 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 help better understand 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 and design study ("FEED study") for the area which is expected to be completed in 2005. If the FEED study confirms favorable development economics, the Company will seek to obtain regulatory approvalto develop the field in 2006, targeting first oil sales in 2008. Simultaneously, the Company is working to secure throughput agreements to process the associated potential oil production at a nearby facility should the project be sanctioned.

During 2001, the Company drilled two South African discovery wells that found quantities of condensate and gas 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 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 plant operator has initiated purchase orders for long-lead time infrastructure components. Currently, negotiations are underway to secure a production contract and it is the Company's expectation that the project will be sanctioned in 2005.

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 2005, the project operator, along with the Company, has approved extended production tests of the existing wells and the drilling of two additional appraisal wells.

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, 2004 and 2003:

	December 31,			
	2004		2003	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(in thousands)			
Derivative contract liabilities:				
Commodity price hedges	$ (406,546)	$ (406,546)	$ (201,422)	$ (201,422)
Unrealized terminated commodity price hedges	$ (660)	$ (660)	$ (1,490)	$ (1,490)
Btu swap contracts	$ -	$ -	$ (6,855)	$ (6,855)
Financial assets:				
Trading securities	$ 11,115	$ 11,115	$ 7,596	$ 7,596
5-1/2% note receivable due 2008	$ 1,786	$ 1,786	$ 2,086	$ 2,086
Financial liabilities - long-term debt:				
Lines of credit	$ (828,000)	$ (828,000)	$ (160,000)	$ (160,000)
8-7/8% senior notes due 2005	$ (131,762)	$ (133,078)	$ (135,239)	$ (141,426)
8-1/4% senior notes due 2007	$ (32,520)	$ (35,465)	$ (155,253)	$ (171,188)
6-1/2% senior notes due 2008	$ (350,326)	$ (374,500)	$ (354,497)	$ (378,725)
9-5/8% senior notes due 2010	$ (62,973)	$ (78,672)	$ (350,558)	$ (424,385)
5-7/8% senior notes due 2012	$ (199,687)	$ (203,198)	$ -	$ -
7-1/2% senior notes due 2012	$ (15,157)	$ (18,621)	$ (150,000)	$ (162,990)
5-7/8% senior notes due 2016	$ (415,609)	$ (549,478)	$ -	$ -
4-3/4% senior convertible notes due 2021 (a)	$ (100,000)	$ (165,598)	$ -	$ -
7-1/5% senior notes due 2028	$ (249,916)	$ (287,500)	$ (249,914)	$ (270,312)

(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 K 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 5-1/2 percent note receivable due 2008 was determined based on underlying market rates of interest. The current portion of the 5-1/2% note receivable due 2008, amounting to $.4 million as of December 31, 2004 and 2003, is included in other current assets in the Company's Consolidated Balance Sheets. The trading securities and the noncurrent portions of the 5-1/2% note receivable due 2008 are included in other assets 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 gains (losses) and issuance discounts and premiums, consisted of the following components at December 31, 2004 and 2003:

	December 31,	
	2004	2003
	(in thousands)	
Outstanding debt principal balances:		
Lines of credit	$ 828,000	$ 160,000
8-7/8% senior notes due 2005	130,950	130,950
8-1/4% senior notes due 2007	32,075	150,000
6-1/2% senior notes due 2008	350,000	350,000
9-5/8% senior notes due 2010	64,044	339,169
5-7/8% senior notes due 2012	194,485	-
7-1/2% senior notes due 2012	16,175	150,000
5-7/8% senior notes due 2016	526,875	-
4-3/4% senior convertible notes due 2021	100,000	-
7-1/5% senior notes due 2028	250,000	250,000
	2,492,604	1,530,119
Issuance discounts and premiums, net	(103,170)	(2,033)
Net deferred fair value hedge gains (losses)	(3,484)	27,375
Total long-term debt	$ 2,385,950	$ 1,555,461

Principal maturities of long-term debt at December 31, 2004 are as follows (in thousands):

2005	$ 130,950
2006	$ 800,000
2007	$ 32,075
2008	$ 378,000
2009	$ -
Thereafter	$ 1,151,579

During the year ending December 31, 2005, $131 million of the Company's 8-7/8% senior notes due 2005 (the "8-7/8 Notes") will mature and the first anniversary of the Company's 364-Day Credit Agreement will occur. The Company intends to initially utilize unused borrowing capacity under its 364-Day Credit Agreement to repay the 8-7/8% Notes and to transfer outstanding borrowings, if any, under the 364-Day Credit Agreement to the Company's five-year unsecured revolving credit agreement (the "Revolving Credit Agreement") on its first anniversary. As a result of the Evergreen merger, the $100 million of 4 3/4% senior convertible notes due 2021 (the "Convertible Notes") are redeemable at any time 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 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 exercise their rights to redeem the Convertible Notes prior to December 20, 2006, the Company intends to refinance the cash redemption costs with unused borrowing capacity underthe Revolving Credit Agreement. The Convertible Notes are reflected in "Thereafter" in the above maturities table. Accordingly, the Company has classified these debt obligations as long-term in its Consolidated Balance Sheet as of December 31, 2004.

Lines of credit. In December 2003, the Company entered into the Revolving Credit Agreement, as amended, that matures in December 2008. The terms of the Revolving Credit Agreement provide for initial aggregate loan commitments of $700 million from a syndication of participating banks (the "Lenders"). Aggregate loan commitments under the Revolving Credit Agreement may be increased to a maximum aggregateamount of $1 billion if the Lenders increase their loan commitments or if loan commitments of new financial institutions are added to the Revolving Credit Agreement. During June 2004, the Company entered into a first amendment (the "First Amendment") to its Revolving Credit Agreement. As a result of the First Amendment, Pioneer Natural Resources USA, Inc., a wholly-owned subsidiary of the Company ("Pioneer USA"), is no longer a guarantor of the Revolving Credit Agreement. Borrowings under the Revolving Credit Agreement may be in the formof revolving loans or swing line loans. Aggregate outstanding swing line loans may not exceed $80 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 fromtime to time by JPMorgan Chase Bank (5.25 percent per annum at December 31, 2004) or the weighted average of the rates on overnight Federal funds transactions with members of the Federal Reserve System during the last preceding business day plus 50 basis point (2.47 percent per annum at December 31, 2004) or (b) a base Eurodollar rate, substantially equal to the London Interbank Offered Rate ("LIBOR") (2.34 percent per annum at December 31, 2004), plus a margin that is based on a grid of the Company's debt rating (100 basis points per annum at December 31, 2004). 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. The Company pays commitment fees on the undrawn amounts under the Revolving Credit Agreement based on a grid of the Company's debt rating (.25 percent per annum at December 31, 2004). As of December 31, 2004, the Company had $28 million borrowed under the Revolving Credit Agreement.

In September 2004, the Company entered into the 364-Day Credit Agreement, as amended, that provided for initial loan commitments of $900 million. The 364-Day Credit Agreement was utilized to finance the Evergreen merger. Borrowings under the 364-Day Credit Agreement may, at the option of the Company, be designated to bear interest based on (a) a rate per annum equal to the higher of the prime rate announced from time to time by JPMorgan Chase Bank or the weighted average of the rates on overnight Federal funds transactions with members of the Federal Reserve System during the last preceding business day plus 50 basis points or (b) a base Eurodollar rate, substantially equal to LIBOR, plus a margin that is based on a grid of the Company's debt rating (75 basis points per annum at December 31, 2004). The Company pays commitment fees on the undrawn amounts under the 364-Day Credit Agreement based on grid of the Company's debt rating (.25 percent per annum at December 31, 2004). As of December 31, 2004, the Company had $800 million revolving loans outstanding on the 364-Day Credit Agreement.

The Revolving Credit Agreement and 364-Day Credit Agreement (collectively the "Lines of Credit") share similar restrictive covenants. Those restrictive covenants include the 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; maintenance of a ratio of total debt to book capitalization less intangible assets (other than intangible oil and gas assets), accumulated other comprehensive income and certain noncash asset write-downs not to exceed .60 to 1.0; and if the Company should fall below an investment grade rating, maintenance of an annual ratio of the net present value of the Company's oil and gas properties to total debt of at least 1.25 to 1.00. The Company was in compliance with all of its debt covenants as of December 31, 2004.

As of December 31, 2004, the Company had $57.1 million of undrawn letters of credit, of which $49.3 million were undrawn commitments under the Lines of Credit. The letters of credit outstanding under the Revolving 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 (100 basis points at December 31, 2004) plus .125 percent. As of December 31, 2004, the Company had unused borrowing capacity of $722.7 million under the Lines of Credit. During February 2005, the Company requested a $250 million reduction in the loan commitments under the 364-Day Credit Agreement to $650 million.

In January 2005, the Company amended the Lines of Credit primarily to (i) provide for the Company's ability to enter into volumetric production payment agreements and (ii) to clarify certain definitional matters.

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. The indentures of the Company's senior notes provide for subsidiary guarantees equivalent to any such guarantees provided under the Revolving Credit Agreement. Accordingly, the First Amendment also had the effect of removing Pioneer USA as a guarantor of the Company's senior notes.

On July 15, 2004, the Company accepted tenders to exchange $117.9 million, $275.1 million and $133.8 million in principal amount of its 8 1/4% senior notes due 2007 (the "8 1/4% Notes"), 9-5/8% senior notes due 2010 (the "9-5/8% Notes") and 7.50% senior notes due 2012 (the "7.50% Notes" and collectively with the 8 1/4% Notes and the 9-5/8% Notes, the "Old Notes"), respectively, for a like principal amount of a new series of 5.875% senior notes due 2016 (the "New Notes") and cash. The aggregate exchange price paid to the holders of the tendered notes exceeded their aggregate principal balances by $109.0 million, which amount was paid in cash to holders of the New Notes. In accordance with EITF Abstract Issue No. 96-19, "Debtors Accounting for a Modification or Exchange of Debt Instruments", this amount is being amortized as an increase to the Company's interest expense over the term of the New Notes. In connection with the tenders of the 9-5/8% Notes and the 7.50% Notes, the Company received consents which permanently removed substantially all of the operating restrictions with respect to those notes once certain investment grade ratings were achieved. Associated with the tenders to exchange the Old Notes, the Company incurred direct transaction costs of $2.2 million during the year ended December 31, 2004, which were recorded as charges to other expense in the accompanying Consolidated Statements of Operations.

Interest on the New Notes is payable semiannually on January 15 and July 15 of each year, commencing January 15, 2005. The New Notes are governed by an indenture between the Company and The Bank of New York dated January 13, 1998. The New Notes are general unsecured obligations of the Company 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.

In connection with the Evergreen merger, the Company assumed the position of Evergreen as the issuer of the Convertible Notes and $200 million of 5.875% Senior Subordinated Notes due 2012 (the "EVG 5.875% Notes"). In addition to a 4.75 percent fixed annual rate of interest, the Company is required to pay contingent interest to the holders of the Convertible Notes. The rate of contingent interest payable in respect to any six-month period equals the greater of (i) a per annum rate equal to five percent of the Company's estimated per annum borrowing rate for senior nonconvertible fixed-rate debt with a maturity date comparable to the Convertible Notes or (ii) .30 percent per annum. In no event may the contingent interest rate exceed .40 percent per annum. The Company is accruing contingent interest on the Convertible Notes at the rate of .30 per annum.

The Convertible Notes are due on December 15, 2021 but are redeemable at either the Company's option or the holder's option on other specified dates. As a result of the Evergreen merger, the Convertible Notes are convertible at any time by the holders as discussed in the following paragraph. Holders may also require the Company to repurchase all or part of the Convertible Notes on December 20, 2006, December 15, 2011 or December 15, 2016 at a repurchase price of 100 percent of the principal amount of the Convertible Notes plus accrued and unpaid interest (including contingent interest). On December 20, 2006, the Company may redeem the Convertible Notes in whole or in part in cash, in shares of common stock, or in any combination of cash and common stock. On December 15, 2011 or December 15, 2016, the Company must pay the repurchase price in cash. The Company, currently, intends to exercise its rights under the indenture and redeem the Convertible Notes on December 20, 2006, if the Convertible Notes have not been redeemed by the holders.

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 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.

The EVG 5.875% Notes assumed in the Evergreen merger are due on March 15, 2012 with interest payable on March 15 and September 15 of each year. The EVG 5.875% Notes were unsecured senior subordinated indebtedness, were subordinated in right of payment to all of the Company's existing and future senior indebtedness, and ranked equally in right of payment with all of the Company's future senior unsecured subordinated indebtedness. Prior to March 15, 2007, the Company may redeem up to 35 percent of the originalprincipal amount of the EVG 5.875% Notes with the net cash proceeds of one or more equity offerings at a redemptionprice of 105.875 percent of the principal amount of the EVG 5.875% Notes, plus accrued and unpaid interest. On or after March 15, 2008, the Company may redeem all or a portion of the EVG 5.875% Notes at redemption prices ranging from 102.938 percent to 100 percent of the principal amount, as provided by the indenture for the EVG 5.875% Notes. The EVG 5.875% Notes also contain provisions for redemption at the holders' option upon the occurrence of certain future events, including a change in control. During October 2004, the Company, pursuant to the indenture for the EVG 5.875% Notes, commenced an offer, in connection with the change of control of Evergreen (the "Change of Control Offer"), to repurchase any or all of the EVG 5.875% Notes at a purchase price in cash equal to 101 percent of the principal amount of the EVG 5.875% Notes, plus accrued and unpaid interest. The Change of Control Offer expired on November 10, 2004. In addition to the Change of Control Offer, during October 2004 the Company solicited consents to proposed amendments to the EVG 5.875% Notes indenture to:

- eliminate the subordination of the right of payment on the EVG 5.875% Notes to the payment in full of all existing and future senior indebtedness of Pioneer;
- amend restrictive covenants applicable to the EVG 5.875% Notes so that they are the same as the restrictive covenants in the Company's senior notes that were originally issued as high-yield notes; and
- amend the provisions of the EVG 5.875% Notes that suspend the restrictive covenants when the EVG 5.875% Notes have certain investment grade ratings so that those provisions are the same as the suspension and permanent-elimination provisions in Pioneer's senior notes that were originally issued as high-yield notes.

Holders of a majority in outstanding principal amountof the EVG 5.875% Notes approved the proposed amendments on October 29, 2004. As a result, the EVG 5.875% Notes are no longer subordinated.

As of December 31, 2004, the aggregate carrying value of the Company's senior notes was net of $3.5 million of unamortized net deferred hedge losses realized from terminated fair value hedge interest rate swap contracts. As of December 31, 2003, the aggregate carrying value of the Company's senior notes included $27.4 million of incremental carrying value attributable to unamortized net deferred hedge gains. See Note K for additional information regarding terminated fair value hedge interest rate swap contracts.

Early extinguishment of debt and capital cost obligation. In conjunction with the Change of Control Offer, the Company repurchased $5.5 million of the EVG 5.875% 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 8-7/8 percent senior notes and repaid its former revolving credit agreement prior to its scheduled maturity. The Company recognized $1.5 million of chargesto other expense associated with these debt extinguishments.

During 2002, the Company repurchased $47.1 million of the 9-5/8% Notes, $13.9 million of the 8-7/8 percent senior notes and repaid a $45.2 million capital cost obligation. The Company recognized a charge to other expense of $22.3 million associated with these debt extinguishments.

Interest expense. The following amounts have been incurred and charged to interest expense for the years ended December 31, 2004, 2003 and 2002:

	Year Ended December 31,		
	2004	2003	2002
		(in thousands)	
Cash payments for interest	$ 110,135	$ 117,870	$ 113,827
Accretion/amortization of discounts or premiums on loans	3,683	2,873	5,488
Amortization of net deferred hedge gains (see Note K)	(19,220)	(26,114)	(14,108)
Amortization of capitalized loan fees	2,059	2,528	2,436
Kansas ad valorem tax (see Note J)	65	103	375
Argentina accrued tax liability	1,205	-	-
Net change in accruals	7,476	(424)	48
Interest incurred	105,403	96,836	108,066
Less capitalized interest	(2,016)	(5,448)	(12,251)
Total interest expense	$ 103,387	$ 91,388	$ 95,815

NOTE G. Related Party Transactions

Activities with affiliated partnerships. 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, 2004, 2003 and 2002:

	Year Ended December 31,		
	2004	2003	2002
		(in thousands)	
Receipt of lease operating and supervision charges in accordance with standard industry operating agreements	$ 1,458	$ 1,473	$ 1,495
Reimbursement of general and administrative expenses	$ 193	$ 148	$ 127

NOTE H. Incentive Plans

Retirement Plans

Deferred compensation retirement plan. In August 1997, the Compensation Committee of the Board of Directors approved a deferred compensation retirement plan for the officers and certain key employees of the Company. Each officer and key employee is allowed to contribute up to 25 percent of their base salary 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 $.9 million, $.9 million and $.8 million for the years ended December 31, 2004, 2003 and 2002, respectively.

401(k) plan. The Pioneer Natural Resources USA, Inc. 401(k) and Matching Plan (the "401(k) Plan") is a defined contribution plan established under the Internal Revenue Code Section 401. The 401(k) Plan was formed by the merger of the Pioneer Natural Resources USA, Inc. 401(k) Plan and the Pioneer Natural Resources USA, Inc. Matching Plan on January 1, 2002. All regular full-time and part-time employees of Pioneer USA are eligible to participate in the 401(k) Plan on the first day of the month following their date of hire. Participants may contribute an amount of not less than two percent nor more than 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 basic compensation (the "Matching Contribution"). Each participant's account is credited with the participant's contributions, their Matching Contributions and allocations of the 401(k) Plan's earnings. Participants are fully vested in their account balances except for Matching Contributions and their proportionate share of 401(k) Plan earnings attributable to Matching Contributions, which proportionately vest over a four-year period that begins with the participant's date of hire. During the years ended December 31, 2004, 2003 and 2002, the Company recognized compensation expense of $5.4 million, $4.5 million and $4.1 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 10 percent of the total number of shares of common stock equivalents outstanding less the total number of shares of common stock subject to outstanding awards under any stock-based plan for the directors, officers or employees of the Company.

The following table calculates the number of shares or options available for grant under the Company's Long-Term Incentive Plan as of December 31, 2004 and 2003:

	December 31,	
	2004	2003
Shares outstanding, net of treasury stock	144,831,662	119,287,772
Outstanding awards exercisable or exercisable within 60 days	4,526,415	3,279,024
	149,358,077	122,566,796
Maximum shares/options allowed under the Long-Term Incentive Plan	14,935,808	12,256,680
Less: Outstanding awards under the Long-Term Incentive Plan	(4,790,028)	(5,534,037)
Outstanding awards under predecessor incentive plans	(1,838,543)	(417,052)
Shares/options available for future grant	8,307,237	6,305,591

Stock option awards. Prior to 2004, the Company had a program of awarding semiannual stock options to its employees. The Company also gives its non-employee directors a choice to receive (i) 100 percent restricted stock, (ii) 100 percent stock options, (iii) 100 percent cash, or (iv) a combination of 50/50 of any two, as their annual compensation. This program provides for stock option awards at an exercise price based upon the closing sales price of the Company's common stock on the day prior to the date of grant. Stock option awards vest over an 18-month or three-year schedule and provide a five-year exercise period from each vesting date. Non-employee directors' stock options vest quarterly and provide for a five-year exercise period from each vesting date. The Company granted 1,353,988 and 1,643,212 options under the Long-Term Incentive Plan during the years ended December 31, 2003 and 2002, respectively.

In accordance with the 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 the year ended December 31, 2004.

Restricted stock awards. During the year ended December 31, 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.

During the years ended December 31, 2003 and 2002, the Company issued 77,625 and 654,445 restricted shares of the Company's common stock, respectively. The restricted share awards were issued as compensation to directors, officers and key employees of the Company.

The Company recorded $19.1 million, $1.1 million and $16.2 million of deferred compensation associated with restricted stock awards in the stockholders' equity section during the years ended December 31, 2004, 2003 and 2002, respectively. Such amounts will be amortized to compensation expense over the vesting periods of the awards. During the years ended December 31, 2004, 2003 and 2002, amortization of restricted stock awards increased the Company's compensation expense by $12.5 million, $5.4 million and $1.9 million, respectively.

The following table reflects the outstanding restricted stock awards as of December 31, 2004, 2003 and 2002 and activity related thereto for the years then ended:

	Year Ended December 31,					
	2004		2003		2002	
	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	676,973	$ 24.79	652,793	$ 24.72	-	$ -
Evergreen awards assumed	214,186	$ 32.58	-	$ -	-	$ -
Shares granted	630,937	$ 31.29	77,625	$ 25.39	654,445	$ 24.72
Shares forfeited	(32,174)	$ 30.99	(36,500)	$ 24.72	-	$ -
Lapse of restrictions	(41,935)	$ 33.03	(16,945)	$ 25.59	(1,652)	$ 24.60
Outstanding at end of year	1,447,987	$ 28.46	676,973	$ 24.79	652,793	$ 24.72

A summary of the Company's stock option plans as of December 31, 2004, 2003 and 2002, and changes during the years then ended, are presented below:

	Year Ended December 31,					
	2004		2003		2002	
	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	5,274,116	$ 20.13	7,268,292	$ 19.60	6,926,071	$ 18.16
Evergreen options assumed	2,384,657	$ 11.18	-	$ -	-	$ -
Options granted	-	$ -	1,353,988	$ 24.84	1,643,212	$ 21.14
Options forfeited	(102,890)	$ 22.24	(1,286,370)	$ 29.22	(154,717)	$ 26.27
Options exercised	(2,375,299)	$ 14.39	(2,061,794)	$ 15.68	(1,146,274)	$ 12.19
Outstanding at end of year	5,180,584	$ 18.60	5,274,116	$ 20.13	7,268,292	$ 19.60
Exercisable at end of year	3,970,996	$ 17.08	2,581,256	$ 17.56	4,269,659	$ 20.15
Weighted average fair value of options granted during the year	$ - (a)		$ 8.95		$ 8.87	

(a) The Company did not grant any stock options under the Long-Term Incentive Plan during the year ended December 31, 2004. The assumed Evergreen options were valued at $32.578 per share.

The following table summarizes information about the Company's stock options outstanding and options exercisable at December 31, 2004:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding at December 31, 2004	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number Exercisable at December 31, 2004	Weighted Average Exercise Price
$ 5-11	923,207	2.4 years	$ 8.62	923,207	$ 8.62
$ 12-18	2,051,553	3.6 years	$ 16.71	1,810,616	$ 16.50
$ 19-26	2,070,455	4.3 years	$ 24.11	1,101,804	$ 23.42
$ 27-30	104,657	1.7 years	$ 28.44	104,657	$ 28.44
$ 31-43	30,712	2.1 years	$ 40.06	30,712	$ 40.06
	5,180,584			3,970,996	

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

Under SFAS 123, the fair value of each stock option grant is estimated on the date of grant using the Black-Scholes option pricing model. The Company did not grant any stock options during the year ended December 31, 2004.

The following weighted average assumptions were used to estimate the value of options granted during the years ended December 31, 2003 and 2002:

	Year Ended December 31,	
	2003	2002
Risk-free interest rate	3.06%	2.80%
Expected life	5 years	5 years
Expected volatility	36%	45%
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, 2004 and 2003, the Company had recorded $15.5 million and $15.6 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, 2004 or 2003. Other than the Company's retirement plan, the participants of these plans are not current employees of the Company.

The accumulated postretirement benefit obligations pertaining to these plans were determined by independent actuaries for four plans representing $11.4 million of unfunded accumulated postretirement benefit obligations as of December 31, 2004 and by the Company for one plan representing $4.1 million of unfunded accumulated postretirement benefit obligations as of December 31, 2004. Interest costs at an annual rate of six percent of the periodic undiscounted accumulated postretirement benefit obligations were employed inthe 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 11 percent in 2005, declining to five percent in 2011 and thereafter, and annual dental cost escalation trends of seven percent in 2005, declining to five 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, 2004, 2003 and 2002:

	Year Ended December 31,		
	2004	2003	2002
		(in thousands)	
Beginning accumulated postretirement benefit obligations	$ 15,556	$ 19,743	$ 19,750
Benefit payments	(1,497)	(1,472)	(1,702)
Service costs	258	205	205
Net actuarial gains	(32)	(4,410)	-
Accretion of discounts	909	1,490	1,490
Fair value of Evergreen obligations assumed	340	-	-
Ending accumulated postretirement benefit obligations	$ 15,534	$ 15,556	$ 19,743

Estimated benefit payments and service costs associated with the plans for the year ended December 31, 2005 are $1.5 million and $1.4 million, respectively.

NOTE I. Issuance of Common Stock

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

NOTE J. Commitments and Contingencies

Severance agreements. The Company has entered into severance agreements with its officers, subsidiary company officers and certain key employees. Salaries and bonuses for the Company's officers are set by the Company's board of directors for the parent company officers and by the Company's management committee for subsidiary company officers and key employees. The Company's board of directors 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 $23.6 million.

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

Legal actions. The Company is party to various legal actions incidental to its business, including, but not limited to, the proceedings described below. The majority of these lawsuits primarily involve claims for damages arising from oil and gas leases and ownership interest disputes. The Company believes that the ultimate disposition of these legal actions will not have a material adverse effect on the Company's consolidated financial position, liquidity, capital resources or future results of operations. The Company will continue to evaluate its litigation matters on a quarter-by-quarter basis and will adjust its litigation reserves as appropriate to reflect the then current status of litigation.

Alford. The Company is party to a 1993 class action lawsuit filed in the 26th Judicial District Court of Stevens County, Kansas by two classes of royalty owners, one for each of the Company's gathering systems connected to the Company's Satanta gas plant. The case was relatively inactive for several years. In early 2000, the plaintiffs amended their pleadings and the case now contains two material claims. First, the plaintiffs assert that they were improperly charged expenses (primarily field compression), which are a "cost of production", and for which the plaintiffs, as royalty owners, are not responsible. Second, the plaintiffs claim they are entitled to 100 percent of the value of the helium extracted at the Company's Satanta gas plant. If the plaintiffs were to prevail on the above two claims in their entirety, it is possible that the Company's liability (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 $30 million related to the cost of production claim and approximately $40 million related to the helium claim, plus prejudgment interest. However, the Company believes it has valid defenses to the plaintiffs' claims, 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 to 100 percent of the value of the helium extracted, and believes that in accordance with applicable law, it has properly accounted to the plaintiffs for their fractional royalty share of the helium under the specified royalty clauses of the respective oil and gas leases. The 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.

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

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

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

The Company and other producers filed petitions for adjustment with the FERC on June 24, 1997. The Company was seeking a waiver or set-off from the FERC with respect to that portion of the refund associated with (i) nonrecoupable royalties, (ii) nonrecoupable Kansas property taxes based, in part, upon the higher prices collected and (iii) interest for all periods. On September 10, 1997, FERC denied this request, and on October 10, 1997, the Company and other producers filed a request for rehearing. Pipelines were given until November 10, 1997 to file claims on refunds sought from producers and refund claims totaling approximately $30.2 million were made against the Company. As of December 31, 2004, the Company has settled all of the original claim amounts and believes it has no further obligation related to this case.

Lease agreements. The Company leases offshore production facilities, equipment and office facilities under noncancellable operating leases. Rental expenses associated with these operating leases for the years ended December 31, 2004, 2003 and 2002 were approximately $51.8 million, $15.5 million and $6.7 million, respectively. Future minimum lease commitments under noncancellable operating leases at December 31, 2004 are as follows (in thousands):

2005	$ 56,365
2006	$ 48,821
2007	$ 34,294
2008	$ 20,199
2009	$ 12,448
Thereafter	$ 13,214

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. The transportation commitments are for approximately 132 million cubic feet ("MMcf") of gross gas sales volumes per day during 2005, declining to approximately 40 MMcf of gross gas sales volumes per day during 2014.

One of the Company's Canadian subsidiaries is a party to pipeline transportation service agreements, with remaining terms of approximately 11 years, whereby it has committed to transport a specified volume of gas each year from Canada to a point in Chicago. Such gas volumes 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 78 MMcf of gas per day during 2005 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 $1.2 million, $.9 million and $2.6 million of gas marketing losses in other expense during the years ended December 31, 2004, 2003 and 2002, respectively.

Future minimum transportation fees under the Company's gas transportation commitments at December 31, 2004 are as follows (in thousands):

2005	$ 58,622
2006	$ 59,705
2007	$ 59,992
2008	$ 59,687
2009	$ 59,242
Thereafter	$ 287,021

NOTE K. 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 minimizing its cost of capital. During the three-year period ending December 31, 2004, the Company, from time to time, entered into interest rate swap contracts to hedge a portion of the fair value of its senior notes. The terms of the interest rate swap contracts were for notional amounts that matched the scheduled maturity of the hedged senior notes, required the counterparties to pay the Company a fixed annual interest rate equal to the stated bond coupon rates on the notional amounts and required the Company to pay the counterparties variable annual interest rates on the notional amounts equal to the periodic six-month LIBOR plus a weighted average annual margin. 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 years ended December 31, 2003 and 2002, the Company terminated fair value hedge interest rate swap contracts for cash proceeds, including accrued interest, of $21.5 million and $36.3 million, respectively. The proceeds attributable to the fair value of the remaining terms of the terminated contracts amounted to $18.3 million and $32.0 million and are included in "Proceeds from disposition of assets" in the accompanying Consolidated Statements of Cash Flows during the years ended December 31, 2003 and 2002, respectively. During the years ended December 31, 2004, 2003 and 2002, settlements of open fair value hedges reduced the Company's interest expense by $2.2 million, $29.3 million and $25.3 million, respectively. As of December 31, 2004, the Company was not a party to any open fair value hedges.

As of December 31, 2004, the carrying value of the Company's long-term debt in the accompanying Consolidated Balance Sheets included a $3.5 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 $19.2 million, $26.1 million and $14.1 million during the years ended December 31, 2004, 2003 and 2002, respectively.

The terms of the fair value hedge agreements described above perfectly matched the terms of the hedged senior notes. Accordingly, the Company did not realize any hedge ineffectiveness associated with its fair value hedges during the years ended December 31, 2004, 2003 or 2002.

The following table sets forth, as of December 31, 2004, the scheduled amortization of net deferred hedge gains (losses) on terminated interest rate hedges, including $3.4 million of deferred losses on terminated cash flow interest rate 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:

	First Quarter	Second Quarter	Third Quarter (in thousands)	Fourth Quarter	Total
2005 net deferred hedge gains	$ 2,213	$ 1,300	$ 880	$ 569	$ 4,962
2006 net deferred hedge gains (losses)	$ 440	$ 191	$ 79	$ (86)	624
2007 net deferred hedge losses	$ (227)	$ (427)	$ (708)	$ (860)	(2,222)
2008 net deferred hedge losses	$ (461)	$ (470)	$ (478)	$ (528)	(1,937)
2009 net deferred hedge losses	$ (523)	$ (596)	$ (605)	$ (627)	(2,351)
2010 net deferred hedge losses	$ (619)	$ (203)	$ (208)	$ (211)	(1,241)
Thereafter					(4,672)
					$ (6,837)

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. The Company has also, from time to time, utilized 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. 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, 2004:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Yearly Outstanding Average
Average daily oil production hedged (a):					
2005 - Swap Contracts					
Volume (Bbl)	27,000	27,000	27,000	27,000	27,000
Price per Bbl	$ 27.97	$ 27.97	$ 27.97	$ 27.97	$ 27.97
2006 - Swap Contracts					
Volume (Bbl)	14,500	14,500	14,500	14,500	14,500
Price per Bbl	$ 34.12	$ 34.12	$ 34.12	$ 34.12	$ 34.12
2006 - Collar Contracts					
Volume (Bbl)	3,500	3,500	3,500	3,500	3,500
Price per Bbl	$35.00-$41.95	$35.00-$41.95	$35.00-$41.95	$35.00-$41.95	$35.00-$41.95
2007 - Swap Contracts					
Volume (Bbl)	17,000	17,000	17,000	17,000	17,000
Price per Bbl	$ 32.59	$ 32.59	$ 32.59	$ 32.59	$ 32.59
2008 - Swap Contracts					
Volume (Bbl)	21,000	21,000	21,000	21,000	21,000
Price per Bbl	$ 30.72	$ 30.72	$ 30.72	$ 30.72	$ 30.72
2009 - Swap Contracts					
Volume (Bbl)	3,500	3,500	3,500	3,500	3,500
Price per Bbl	$ 36.48	$ 36.48	$ 36.48	$ 36.48	$ 36.48
2010 - Swap Contracts					
Volume (Bbl)	1,000	1,000	1,000	1,000	1,000
Price per Bbl	$ 36.10	$ 36.10	$ 36.10	$ 36.10	$ 36.10
2011 - Swap Contracts					
Volume (Bbl)	2,000	2,000	2,000	2,000	2,000
Price per Bbl	$ 35.93	$ 35.93	$ 35.93	$ 35.93	$ 35.93
2012 - Swap Contracts					
Volume (Bbl)	2,000	2,000	2,000	2,000	2,000
Price per Bbl	$ 35.86	$ 35.86	$ 35.86	$ 35.86	$ 35.86

(a) Subsequent to December 31, 2004, the Company conveyed to the purchaser of the Spraberry Volumetric Production Payment ("VPP") 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. See Note U for additional information regarding the Spraberry VPP.

The Company reports average oil prices per Bbl including the effects of oil quality adjustments and the net effect of oil hedges. The following table sets forth the Company's oil prices, both reported (including hedge results) and realized (excluding hedge results), and the net effect of settlements of oil price hedges on oil revenue for the years ended December 31, 2004, 2003 and 2002:

	Year Ended December 31,		
	2004	2003	2002
Average price reported per Bbl	$ 31.38	$ 25.59	$ 22.89
Average price realized per Bbl	$ 37.61	$ 28.80	$ 22.95
Reduction to oil revenue (in millions)	$ (107.2)	$ (41.3)	$ (.8)

Natural gas liquids prices. During the years ended December 31, 2004, 2003 and 2002, the Company did not enter into any NGL hedge contracts. There were no outstanding NGL hedge contracts at December 31, 2004.

Gas prices. The Company employs a policy of hedging a portion of its gas production based on the index price upon which the gas is actually sold in order to mitigate the basis risk between NYMEX prices and actual index prices, or based on NYMEX prices if NYMEX prices are highly correlated with the index price. The following table sets forth the volumes hedged in million British thermal units ("MMBtu") underlying the Company's outstanding gas hedge contracts and the weighted average index prices per MMBtu for those contracts as of December 31, 2004:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Yearly Outstanding Average
Average daily gas production hedged (a):					
2005 - Swap Contracts					
Volume (MMBtu)	296,556	290,000	290,000	260,000	284,055
Index price per MMBtu	$ 5.32	$ 5.19	$ 5.19	$ 5.18	$ 5.22
2006 - Swap Contracts					
Volume (MMBtu)	105,000	104,176	102,500	102,500	103,534
Index price per MMBtu	$ 4.70	$ 4.69	$ 4.67	$ 4.67	$ 4.68
2006 - Collar Contracts					
Volume (MMBtu)	5,000	5,000	5,000	5,000	5,000
Index price per MMBtu	$5.25-$7.15	$5.25-$7.15	$5.25-$7.15	$5.25-$7.15	$5.25-$7.15
2007 - Swap Contracts					
Volume (MMBtu)	55,000	55,000	55,000	55,000	55,000
Index price per MMBtu	$ 4.69	$ 4.69	$ 4.69	$ 4.69	$ 4.69
2008 - Swap Contracts					
Volume (MMBtu)	30,000	30,000	30,000	30,000	30,000
Index price per MMBtu	$ 5.06	$ 5.06	$ 5.06	$ 5.06	$ 5.06
2009 - Swap Contracts					
Volume (MMBtu)	25,000	25,000	25,000	25,000	25,000
Index price per MMBtu	$ 4.72	$ 4.72	$ 4.72	$ 4.72	$ 4.72

(a) Subsequent to December 31, 2004, the Company conveyed to the purchaser of the Hugoton VPP the following gas swap contracts which were included in the schedule 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. See Note U for additional information regarding the Hugoton VPP.

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, 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, 2004, 2003 and 2002:

	Year Ended December 31,		
	2004	2003	2002
Average price reported per Mcf	$ 4.33	$ 3.84	$ 2.58
Average price realized per Mcf	$ 4.83	$ 4.25	$ 2.52
Addition (reduction) to gas revenue (in millions)	$ (125.7)	$ (76.1)	$ 13.6

Interest rate. During June 2004, the Company entered into costless collar contracts and designated the contracts as cash flow hedges of the forecasted interest rate risk attributable to the yield on the benchmark 4.75 percent U.S. Treasury Notes due May 15, 2014 (the "U.S. Treasuries"). The terms of the collar contracts fixed the annual yield on $250 million notional amount of U.S. Treasuries within a yield collar having a ceiling rate of 4.70 percent and a floor rate of 4.65 percent. The yield on the U.S. Treasuries as of July 7, 2004 was the benchmark rate used to determine the coupon rate on the Company's New Notes, which were issued on July 15, 2004 in exchange for portions of the Old Notes. During July 2004, the Company terminated these costless collar contracts for $3.4 million of cash payments. The Company did not realize any ineffectiveness in connection with the costless collar contracts during the year ended December 31, 2004. See Note F for information regarding the July 15, 2004 debt exchange.

Hedge ineffectiveness. During the years ended December 31, 2004, 2003 and 2002, the Company recognized other expense of $4.3 million, $2.8 million and $1.7 million, respectively, related to the ineffective portions of its cash flow hedging instruments. These charges include amounts related to hedge volumes that exceeded revised forecasts of production volumes due to delays in the start-up of production in certain fields.

Accumulated other comprehensive income (loss) - net deferred hedge losses, net of tax ("AOCI - Hedging"). As of December 31, 2004 and 2003, AOCI - Hedging represented net deferred losses of $241.4 and $104.1 million, respectively. 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 cashflow interest rate hedges) and $124.7 million of associated net deferred tax benefits. The AOCI - Hedging balance as of December 31, 2003 was comprised of $200.6 million of net deferred losses on the effective portions of open cash flow hedges, $45.1 million of net deferred gains on terminated cash flow hedges and $51.4 million of associated net deferred tax benefits. The increase in AOCI - Hedging during the year ended December 31, 2004 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 gains (losses) on terminated cash flow hedges are fixed.

During the twelve-month period ending December 31, 2005, based on current estimates of future commodity prices, the Company expects to reclassify $224.1 million of net deferred losses associated with open commodity hedges and $1.7 million of net deferred gains on terminated commodity hedges from AOCI - Hedging to oil and gas revenues. The Company also expects to reclassify approximately $81.2 million of net deferred income tax benefits associated with commodity hedges during the twelve-month period ending December 31, 2005 from AOCI - Hedging to income tax benefit.

The following table sets forth, as of December 31, 2004, the scheduled amortization of net deferred gains (losses) on terminated commodity hedges that will be recognized as increases in the case of gains, or decreases in the case of losses, to the Company's future oil and gas revenues:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
			(in thousands)		
2005 net deferred hedge gains	$ 424	$ 427	$ 432	$ 434	$ 1,717
2006 net deferred hedge losses	$ (330)	$ (332)	$ (333)	$ (330)	(1,325)
					$ 392

NOTE L. 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.

The following customer individually accounted for 10 percent or more of the consolidated oil, NGL and gas revenues of the Company during one or more of the years ended December 31, 2004, 2003 and 2002:

	Year ended December 31,		
	2004	2003	2002
Williams Power Company, Inc.	12%	16%	7%

At December 31, 2004, the Company had no amounts receivable from Williams Power Company, Inc.

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, 2004 and 2003, the Company had $5.3 million of derivative assets for which Enron North America Corp was the Company's counterparty. Associated therewith, the Company had a $4.5 million allowance for doubtful accounts as of December 31, 2004 and 2003.

NOTE M. 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, 2004 and 2003 and in accordance with the provisions of SFAS 19 during the year ended December 31, 2002:

	Year Ended December 31,		
	2004	2003	2002
		(in thousands)	
Beginning asset retirement obligations	$ 105,036	$ 34,692	$ 39,461
Cumulative effect adjustment	-	23,393	-
New wells placed on production and changes in estimates	4,591	46,664	293
Acquisition liabilities assumed	10,488	1,791	-
Liabilities settled	(8,562)	(8,069)	(6,832)
Accretion of discount	8,210	5,040	2,562
Currency translation	1,116	1,525	(792)
Ending asset retirement obligations	$ 120,879	$ 105,036	$ 34,692

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 N. Interest and Other Income

The following table provides the components of the Company's interest and other income during the years ended December 31, 2004, 2003 and 2002:

	Year Ended December 31,		
	2004	2003	2002
		(in thousands)	
Kansas ad valorem escrow adjustments (see Note J)	$ -	$ -	$ 3,500
Business interruption insurance claim	7,563	-	-
Retirement obligation revaluations (see Note H)	32	4,410	-
Excise tax income	3,609	2,369	2,398
Interest income	92	981	642
Seismic data sales	172	424	87
Foreign currency remeasurement and exchange gains (a)	304	657	142
Gain on early extinguishment of debt (see Note F)	95	-	-
Other income	2,207	3,451	4,453
Total interest and other income	$ 14,074	$ 12,292	$ 11,222

(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 O. Asset Divestitures

During the years ended December 31, 2004, 2003 and 2002, the Company completed asset divestitures for net proceeds of $1.7 million, $35.7 million and $118.9 million, respectively. Associated therewith, the Company recorded gains on disposition of assets of $39 thousand, $1.3 million and $4.4 million during the years ended December 31, 2004, 2003 and 2002, respectively.

Hedge derivative divestitures. During the years ended December 31, 2003 and 2002, the Company terminated, prior to their scheduled maturity, hedge derivatives for cash sales proceeds of $18.3 million and $91.3 million, respectively. Net gains from these divestitures were deferred and are amortized overthe original contract lives of the terminated derivatives as reductions to interest expense or increases to oil and gas revenues. See Note K for more information regarding deferred gains and losses on terminated hedge derivatives.

Other United States divestitures. During the year ended December 31, 2004, the Company received $1.2 million of cash proceeds from the sale of other U.S. corporate assets. Associated with these divestitures, the Company recorded $.2 million of net gains. During the year ended December 31, 2003, the Company received $15.2 million of cash proceeds from the sale of unproved property interests and $.9 million of cash proceeds from the sale of other U.S. corporate assets. Associated with these divestitures, the Company recorded $1.5 million of net gains. During the year ended December 31, 2002, the Company received $20.9 million of proceeds from the cash settlement of a gas balancing receivable, $4.7 million from the sale of certain gas properties located in Oklahoma and $1.8 million from the sale of other corporate assets. Associated with these divestitures, the Company recorded net gains of $4.2 million.

NOTE P. Other Expense

The following table provides the components of the Company's other expense during the years ended December 31, 2004, 2003 and 2002:

	Year Ended December 31,		
	2004	2003	2002
		(in thousands)	
Derivative ineffectiveness and mark-to-market provisions (see Note K)	$ 4,341	$ 2,831	$ 1,664
Contingency adjustments (see Note J)	13,552	1,776	-
Debt exchange offer costs (see Note F)	2,248	-	-
Gas marketing losses (see Note J)	1,218	922	2,556
Foreign currency remeasurement and exchange losses (a)	2,949	2,672	7,623
Bad debt expense	3,674	354	129
Loss on early extinguishment of debt (see Note F)	-	1,457	22,346
Argentine personal asset tax	1,094	1,996	-
Other charges	4,611	9,312	5,284
Total other expense	$ 33,687	$ 21,320	$ 39,602

(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 Q. Income Taxes

The Company accounts for income taxes in accordance with the provisions of Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes" ("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 $17.1 million, $5.3 million and $2.3 million were made during the years ended December 31, 2004, 2003 and 2002, 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. From 1998 until 2003, the Company maintained valuation allowances against a portion of its deferred tax asset position in the United States. During 2003, the Company concluded, based on its improved operating results, that it was more likely than not that it would be able to realize its gross deferred tax asset position in the United States. Accordingly, the Company reversed its valuation allowances in the United States.

Pioneer will continue to monitor Company-specific, oil and gas industry and worldwide economic factors and will reassess the likelihood that the Company's net operating loss carryforwards and other deferred tax attributes in the United States and foreign tax jurisdictions will be utilized prior to their expiration. As of December 31, 2004, the Company's valuation allowances related to foreign tax jurisdictions were $108.2 million.

On October 22, 2004, the American Jobs Creation Act (the "AJCA") was signed into law. The AJCA includes a deduction of 85 percent of certain foreign earnings that are repatriated, as defined in the AJCA. The Company may elect to apply this provision to qualifying earnings repatriations in 2005. The Company has started an evaluation of the effects of the repatriation provision; however, the Company does not expect to be able to complete this evaluation until after Congress or the Treasury Department provide additional clarifying language on key elements of the provision. The Company expects to complete its evaluation of the effects of the repatriation provision within a reasonable period of time following the publication of the additional clarifying language. The range of possible amounts that the Company is considering for repatriation under section 965 of the Internal Revenue Code is between zero and $80 million with a related potential range of income tax between zero and $5 million. Until the Company decides to repatriate any foreign earnings, it will continue to treat them as permanently invested.

During the year ended December 31, 2004, the Company recorded a $26.9 million tax benefit associated with the deduction of the Company's only investment in Gabon resulting from the impairment of the Olowi field. See Note T for additional discussion regarding the impairment of the Gabonese Olowi field.

The Company's income tax provision (benefit) and amounts separately allocated were attributable to the following items for the years ended December 31, 2004, 2003 and 2002:

	Year Ended December 31,		
	2004	2003	2002
		(in thousands)	
Income before cumulative effect of change in accounting principle	$ 166,359	$ (64,403)	$ 5,063
Cumulative effect of change in accounting principle	-	1,312	-
Changes in goodwill - tax benefits related to stock based compensation	(8,955)	-	-
Changes in stockholders' equity:			
Net deferred hedge losses	(73,340)	(51,064)	(2,561)
Tax benefits related to stock-based compensation	(6,612)	(14,666)	-
Translation adjustment	(314)	(324)	(20)
	$ 77,138	$ (129,145)	$ 2,482

Income tax provision (benefit) attributable to income before cumulative effect of change in accounting principle consisted of the following for the years ended December 31, 2004, 2003 and 2002:

	Year Ended December 31,		
	2004	2003	2002
		(in thousands)	
Current:			
U.S. federal	$ 2,500	$ 100	$ -
U.S. state and local	602	-	209
Foreign	22,185	11,085	2,066
	25,287	11,185	2,275
Deferred:			
U.S. federal	138,723	(69,020)	-
U.S. state and local	5,093	(7,291)	-
Foreign	(2,744)	723	2,788
	141,072	(75,588)	2,788
	$ 166,359	$ (64,403)	$ 5,063

Income before income taxes and cumulative effect of change in accounting principle consists of the following for the years ended December 31, 2004, 2003 and 2002:

	Year Ended December 31,		
	2004	2003	2002
		(in thousands)	
Income before income taxes and cumulative effect of change in accounting principle:			
U.S. federal	$ 477,195	$ 335,170	$ 36,475
Foreign	2,018	(4,394)	(4,699)
	$ 479,213	$ 330,776	$ 31,776

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

	Year Ended December 31,		
	2004	2003	2002
	(in percentages)		
U.S. federal statutory tax rate	35.0	35.0	35.0
U.S. valuation allowance reversal	-	(59.8)	(44.1)
Foreign valuation allowances (a)	5.1	13.1	28.2
Rate differential on foreign operations	4.4	(.9)	(.5)
Argentine inflation adjustment (a)	(2.0)	(12.4)	-
Gabon investment deduction	(5.4)	-	-
Other	(2.4)	5.5	(2.7)
Consolidated effective tax rate	34.7	(19.5)	15.9

(a) The Company has applied an inflation adjustment to its 2004, 2003 and 2002 Argentine income tax returns 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 $49.3 million valuation allowance against this tax benefit in its overall foreign valuation allowances.

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, 2004 and 2003:

	December 31,	
	2004	2003
	(in thousands)	
Deferred tax assets:		
Net operating loss carryforwards	$ 303,002	$ 300,296
Alternative minimum tax credit carryforwards	4,144	1,457
Net deferred hedge losses	124,689	56,842
Asset retirement obligations	41,874	29,040
Other	110,677	92,561
Total deferred tax assets	584,386	480,196
Valuation allowances	(108,214)	(94,910)
Net deferred tax assets	476,172	385,286
Deferred tax liabilities:		
Oil and gas properties, principally due to differences in basis, depletion and the deduction of intangible drilling costs for tax purposes	898,753	161,532
Other	66,665	3,017
Total deferred tax liabilities	965,418	164,549
Net deferred tax asset (liability)	$ (489,246)	$ 220,737

At December 31, 2004, the Company had net operating loss carryforwards ("NOLs") for United States, Equatorial Guinea, South Africa and Tunisia 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	Equatorial Guinea NOL	South Africa NOL	Tunisia NOL
			(in thousands)		
December 31, 2007	$ 99,241	$ 57,377	$ -	$ -	$ -
December 31, 2008	105,787	106,558	-	-	-
December 31, 2009	46,110	28,796	-	-	-
December 31, 2010	25,144	15,253	-	-	-
December 31, 2011	3,849	3,149	-	-	-
December 31, 2012	69,098	58,723	-	-	-
December 31, 2018	129,363	99,982	-	-	-
December 31, 2019	149,351	148,070	-	-	-
December 31, 2020	16,723	15,562	-	-	-
December 31, 2021	52,914	49,672	-	-	-
December 31, 2022	41,833	39,950	-	-	-
December 31, 2023	81,564	81,784	-	-	-
Indefinite	-	-	10,105	10,924	16,562
	$ 820,977	$ 704,876	$ 10,105	$ 10,924	$ 16,562

The Company believes $120 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, 2004, 2003 and 2002, the Company utilized $124.2 million, $17.1 million and $34.6 million of NOLs, respectively.

NOTE R. Income Per Share Before Cumulative Effect of Change in Accounting Principle

Basic income per share before cumulative effect of change in accounting principle is computed by dividing income 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 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 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 and diluted earnings before cumulative effect of change in accounting principle for the years ended December 31, 2004, 2003 and 2002:

	Year Ended December 31, 2004	2003	2002
		(in thousands)	
Income before cumulative effect of change in accounting principle	$ 312,854	$ 395,179	$ 26,713
Interest expense on Convertible Notes, net of tax	802	-	-
Diluted income before cumulative effect of change in accounting principle	$ 313,656	$ 395,179	$ 26,713

The following table is a reconciliation of the basic and diluted weighted average common shares outstanding for the years ended December 31, 2004, 2003 and 2002:

	Year Ended December 31,		
	2004	2003	2002
		(in thousands)	
Weighted average common shares outstanding (a):			
Basic	125,156	117,185	112,542
Dilutive common stock options (b)	1,218	1,112	1,725
Restricted stock awards	529	216	21
Convertible Notes dilution	585	-	-
Diluted	127,488	118,513	114,288

(a) Associated with the Evergreen merger on September 28, 2004, the Company issued 25.4 million shares of common stock, assumed 2.4 million of in-the-money stock options, assumed 214,186 restricted stock units and assumed the Convertible Notes.

(b) Common stock options to purchase 30,712 shares, 976,506 shares and 1,925,743 shares of common stock were outstanding but not included in the computations of diluted income per share before cumulative effect of change in accounting principle for the years ended December 31, 2004, 2003 and 2002, 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.

NOTE S. 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 organizationallystructured 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, South Africa and Tunisia.

The following tables provide the geographic operating segment data required by Statement of Financial Accounting Standards No. 131, "Disclosure about Segments of an Enterprise and Related Information", as well as results of operations of oil and gas producing activities required by Statement of Financial Accounting Standards No. 69, "Disclosures about Oil and Gas Producing Activities" as of and for the years ended December 31, 2004, 2003 and 2002. 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 revenues, expenses, additions to property, plant and equipment and assets that are not routinely included in the earnings measures or attributes internally reported to management on a geographic operating segment basis.

	United States	Argentina	Canada	Africa and Other	Headquarters	Consolidated Total
			(in thousands)			
Year Ended December 31, 2004:						
Revenues and other income:						
Oil and gas revenues	$ 1,451,928	$ 134,065	$ 83,749	$ 162,921	$ -	$ 1,832,663
Interest and other	-	-	-	-	14,074	14,074
Gain (loss) on disposition of assets, net	51	-	(252)	-	240	39
	1,451,979	134,065	83,497	162,921	14,314	1,846,776
Costs and expenses:						
Oil and gas production	249,551	33,174	31,269	31,510	-	345,504
Depletion, depreciation and amortization	420,363	61,773	32,123	47,835	12,780	574,874
Impairment of oil and gas properties	-	-	-	39,684	-	39,684
Exploration and abandonments	98,984	23,406	20,000	39,299	-	181,689
General and administrative	-	-	-	-	80,528	80,528
Accretion of discount on asset retirement obligations	-	-	-	-	8,210	8,210
Interest	-	-	-	-	103,387	103,387
Other	-	-	-	-	33,687	33,687
	768,898	118,353	83,392	158,328	238,592	1,367,563
Income (loss) before income taxes	683,081	15,712	105	4,593	(224,278)	479,213
Income tax benefit (provision)	(249,325)	(5,499)	(40)	1,413	87,092	(166,359)
Net income (loss)	$ 433,756	$ 10,213	$ 65	$ 6,006	$ (137,186)	$ 312,854
Cost 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)	$ 5,455,688	$ 708,391	$ 316,124	$ 123,073	$ 43,965	$ 6,647,241

	United States	Argentina	Canada	Africa and Other	Headquarters	Consolidated Total
			(in thousands)			
Year Ended December 31, 2003:						
Revenues and other income:						
Oil and gas revenues	$ 1,056,796	$ 111,315	$ 84,417	$ 21,343	$ -	$ 1,273,871
Interest and other	-	-	-	-	12,292	12,292
Gain (loss) on disposition of assets, net	1,458	-	1	-	(203)	1,256
	1,058,254	111,315	84,418	21,343	12,089	1,287,419
Costs and expenses:						
Oil and gas production	196,915	26,110	28,838	2,887	-	254,750
Depletion, depreciation and amortization	298,005	46,518	28,991	7,729	9,597	390,840
Exploration and abandonments	72,732	18,076	17,691	24,261	-	132,760
General and administrative	-	-	-	-	60,545	60,545
Accretion of discount on asset retirement obligations	-	-	-	-	5,040	5,040
Interest	-	-	-	-	91,388	91,388
Other	-	-	-	-	21,320	21,320
	567,652	90,704	75,520	34,877	187,890	956,643
Income (loss) before income taxes and cumulative effect of change in accounting principle	490,602	20,611	8,898	(13,534)	(175,801)	330,776
Income tax benefit (provision)	(179,070)	(7,214)	(3,426)	4,738	249,375	64,403
Income (loss) before cumulative effect of change in accounting principle	$ 311,532	$ 13,397	$ 5,472	$ (8,796)	$ 73,574	$ 395,179
Cost 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
Year Ended December 31, 2002:						
Revenues and other income:						
Oil and gas revenues	$ 549,675	$ 77,615	$ 67,065	$ -	$ -	$ 694,355
Interest and other	-	-	-	-	11,222	11,222
Gain (loss) on disposition of assets, net	3,248	(3)	995	-	192	4,432
	552,923	77,612	68,060	-	11,414	710,009
Costs and expenses:						
Oil and gas production	151,315	13,870	26,960	-	-	192,145
Depletion, depreciation and amortization	140,107	39,659	27,857	-	8,752	216,375
Exploration and abandonments	62,955	10,306	5,841	6,792	-	85,894
General and administrative	-	-	-	-	48,402	48,402
Interest	-	-	-	-	95,815	95,815
Other	-	-	-	-	39,602	39,602
	354,377	63,835	60,658	6,792	192,571	678,233
Income (loss) before income taxes	198,546	13,777	7,402	(6,792)	(181,157)	31,776
Income tax benefit (provision)	(69,491)	(4,822)	(3,118)	2,377	69,991	(5,063)
Net income (loss)	$ 129,055	$ 8,955	$ 4,284	$ (4,415)	$ (111,166)	$ 26,713
Cost incurred for oil and gas assets	$ 533,560	$ 35,121	$ 33,506	$ 70,268	$ -	$ 672,455

NOTE T. 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 recent increases in steel costs, the project does not offer competitive returns. The Olowi field was the Company's only Gabonese investment. The Company's current Gabonese permit expires in April 2005. The Company has verbally requested an extension to the permit to allow more time for the Company to determine the best manner to exit Gabon, however, no assurance can be given that such extension will be granted. During 2004, the Company recorded an associated impairment charge to eliminate the carrying value of the Company's Gabonese Olowi field of $39.7 million.

NOTE U. Subsequent Event - Volumetric Production Payments

During January 2005, the Company sold two percent of its total proved reserves, or 20.5 million BOE of proved reserves, by means of VPPs for total proceeds of $593 million and the assumption of the Company's obligations under certain derivative hedge agreements. Proceeds from the VPPs were initially used to pay down indebtedness.

The 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 to the purchaser and (v) allows the Company to retain the assets after the VPP's volumetric obligations have been satisfied.

The first VPP sells 58 billion cubic feet of Hugoton field gas volumes over an expected five-year term beginning in February 2005 for $275 million of proceeds. The second VPP sells 10.8 million barrels of oil equivalent ("MMBOE") of Spraberry field oil volumes over an expected seven-year term beginning in January 2006 for $318 million of proceeds.

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

The Company will amortize to oil and gas revenues $62.9 million of net deferred gas revenue during 2005 associated with the Hugoton field VPP. During 2006, the Company will amortize $53.7 million of net deferred gas revenue associated with the Hugoton field VPP and $57.6 million of net deferred oil revenue associated with the Spraberry field VPP.

UNAUDITED SUPPLEMENTARY INFORMATION
Years Ended December 31, 2004, 2003 and 2002

Capitalized Costs

	December 31, 2004	December 31, 2003
	(in thousands)	
Oil and gas properties:		
Proved	$ 7,654,181	$ 4,983,558
Unproved	470,435	179,825
Capitalized costs for oil and gas properties	8,124,616	5,163,383
Less accumulated depletion, depreciation and amortization	(2,243,549)	(1,676,136)
Net capitalized costs for oil and gas properties	$ 5,881,067	$ 3,487,247

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, 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
Year Ended December 31, 2002:						
United States	$ 156,736	$ 34,048	$ 72,831	$ 269,945	$ -	$ 533,560
Argentina	12	51	14,530	20,528	-	35,121
Canada	457	2,329	9,992	20,728	-	33,506
Africa and other	-	1,843	34,125	34,300	-	70,268
Total	$ 157,205	$ 38,271	$ 131,478	$ 345,501	$ -	$ 672,455

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

UNAUDITED SUPPLEMENTARY INFORMATION
Years Ended December 31, 2004, 2003 and 2002

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 S 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, 2004, 2003 and 2002, which are located in the United States, Argentina, Canada, Gabon, South Africa and Tunisia, were based on evaluations audited by independent petroleum engineers with respect to the Company's major properties and prepared by the Company's engineers with respect to all other properties. 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 December31, 2004, 2003 and 2002 utilize respective oil prices of $41.96, $31.10 and $29.67 per Bbl (reflecting adjustments for oil quality), respective NGL prices of $29.12, $20.26 and $19.01 per Bbl, and respective gas prices of $4.76, $4.23 and $3.37 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, 2004 include 6.1 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 following table provides a rollforward of total proved reserves by geographic area and in total for the years ended December 31, 2004, 2003 and 2002, 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 barrels oil equivalent ("MBOE").

UNAUDITED SUPPLEMENTARY INFORMATION
Years Ended December 31, 2004, 2003 and 2002

	Year Ended December 31,								
	2004			2003			2002		
Total Proved Reserves:	Oil & NGLs (MBbls)	Gas (MMcf)	MBOE	Oil & NGLs (MBbls)	Gas (MMcf)	MBOE	Oil & NGLs (MBbls)	Gas (MMcf)	MBOE
UNITED STATES									
Balance, January 1	362,751	1,553,976	621,747	337,631	1,483,971	584,960	279,146	1,474,090	524,829
Revisions of previous estimates	4,671	25,764	8,965	36,823	94,759	52,616	61,529	5,983	62,525
Purchases of minerals-in-place	11,803	1,571,053	273,646	4,422	57,124	13,942	8,634	83,361	22,528
New discoveries and extensions	1,017	56,690	10,465	250	80,769	13,712	4,364	5,349	5,255
Production	(16,974)	(200,598)	(50,407)	(16,375)	(162,647)	(43,483)	(16,042)	(84,812)	(30,177)
Sales of minerals-in-place	(11)	(6,550)	(1,103)	-	-	-	-	-	-
Balance, December 31	363,257	3,000,335	863,313	362,751	1,553,976	621,747	337,631	1,483,971	584,960
ARGENTINA									
Balance, January 1	33,469	549,856	125,112	31,532	532,081	120,211	35,669	471,150	114,193
Revisions of previous estimates	(3,040)	(61,483)	(13,287)	2,027	44,064	9,372	(4,954)	47,829	3,017
New discoveries and extensions	6,428	116,526	25,849	3,562	8,068	4,907	3,985	41,652	10,927
Production	(3,689)	(44,525)	(11,110)	(3,652)	(34,357)	(9,378)	(3,168)	(28,550)	(7,926)
Balance, December 31	33,168	560,374	126,564	33,469	549,856	125,112	31,532	532,081	120,211
CANADA									
Balance, January 1	2,407	93,829	18,045	2,361	119,328	22,249	2,659	132,061	24,669
Revisions of previous estimates	710	8,580	2,140	344	(14,920)	(2,143)	24	(1,150)	(167)
Purchases of mineral-in-place	823	22,127	4,511	-	-	-	-	-	-
New discoveries and extensions	541	10,656	2,317	73	4,630	845	68	6,070	1,080
Production	(386)	(15,323)	(2,940)	(371)	(15,209)	(2,906)	(390)	(17,653)	(3,333)
Balance, December 31	4,095	119,869	24,073	2,407	93,829	18,045	2,361	119,328	22,249
AFRICA									
Balance, January 1	24,154	-	24,154	9,320	-	9,320	7,685	-	7,685
Revisions of previous estimates	(12,111)	-	(12,111)	(1,817)	-	(1,817)	790	-	790
New discoveries and extensions	502	-	502	17,374	-	17,374	845	-	845
Production	(4,274)	-	(4,274)	(723)	-	(723)	-	-	-
Balance, December 31	8,271	-	8,271	24,154	-	24,154	9,320	-	9,320
TOTAL									
Balance, January 1	422,781	2,197,661	789,058	380,844	2,135,380	736,740	325,159	2,077,301	671,376
Revisions of previous estimates	(9,770)	(27,139)	(14,293)	37,377	123,903	58,028	57,389	52,662	66,165
Purchases of minerals-in-place	12,626	1,593,180	278,157	4,422	57,124	13,942	8,634	83,361	22,528
New discoveries and extensions	8,488	183,872	39,133	21,259	93,467	36,838	9,262	53,071	18,107
Production	(25,323)	(260,446)	(68,731)	(21,121)	(212,213)	(56,490)	(19,600)	(131,015)	(41,436)
Sales of minerals-in-place	(11)	(6,550)	(1,103)	-	-	-	-	-	-
Balance, December 31	408,791	3,680,578	1,022,221	422,781	2,197,661	789,058	380,844	2,135,380	736,740
Proved Developed Reserves:									
United States	209,349	1,202,264	409,727	209,948	1,067,701	387,899	196,893	1,027,750	368,184
Argentina	21,149	352,660	79,926	22,180	402,640	89,287	28,248	341,967	85,243
Canada	2,312	86,500	16,728	2,042	90,003	17,042	2,086	94,607	17,854
Africa	6,817	-	6,817	-	-	-	-	-	-
Balance, January 1	239,627	1,641,424	513,198	234,170	1,560,344	494,228	227,227	1,464,324	471,281
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, December 31	256,434	2,473,438	668,673	239,627	1,641,424	513,198	234,170	1,560,344	494,228

• The proved gas reserves as of December 31, 2004 include 271.7 MMcf ofgas 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 toa sales point. The above production amounts for 2004 include approximately 9,600 MMcf of field fuel.

PIONEER NATURAL RESOURCES COMPANY

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Years Ended December 31, 2004, 2003 and 2002

Standardized Measure of Discounted Future Net Cash Flows

The standardized measure of discounted future net cash flows is computed by applying year-end prices of oil and gas (with consideration of price changes only to the extent provided by contractual arrangements) to the estimated future production of proved oil and gas reserves less estimated future expenditures (based on year-end costs) to be incurred in developing and producing the proved reserves, discounted using a rate of 10 percent per year to reflect the estimated timing of the future cash flows. Future income taxes are calculated by comparing undiscounted future cash flows to the tax basis of oil and gas properties plus available carryforwards and credits and applying the current tax rates to the difference. The discounted future cash flow estimates do not include the effects of the Company's commodity hedging contracts. Utilizing December 31, 2004 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 10 percent, was a liability of approximately $291 million at December 31, 2004.

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
Years Ended December 31, 2004, 2003 and 2002

The following tables provide the standardized measure of discounted future cash flows by geographic area and in total for the years ended December 31, 2004, 2003 and 2002, as well as a rollforward in total for each respective year:

	Year Ended December 31,		
	2004	2003	2002
		(in thousands)	
UNITED STATES			
Oil and gas producing activities:			
Future cash inflows	$ 28,373,520	$ 17,760,911	$ 14,725,914
Future production costs	(8,232,530)	(5,440,383)	(4,394,491)
Future development costs	(1,829,937)	(1,188,394)	(864,386)
Future income tax expense	(5,612,935)	(3,057,968)	(2,325,946)
	12,698,118	8,074,166	7,141,091
10% annual discount factor	(7,116,815)	(4,276,678)	(3,684,400)
Standardized measure of discounted future cash flows	$ 5,581,303	$ 3,797,488	$ 3,456,691
ARGENTINA			
Oil and gas producing activities:			
Future cash inflows	$ 1,747,737	$ 1,257,068	$ 986,716
Future production costs	(289,742)	(233,399)	(175,938)
Future development costs	(234,309)	(136,663)	(84,669)
Future income tax expense	(221,733)	(161,683)	(143,845)
	1,001,953	725,323	582,264
10% annual discount factor	(354,661)	(282,205)	(242,158)
Standardized measure of discounted future cash flows	$ 647,292	$ 443,118	$ 340,106
CANADA			
Oil and gas producing activities:			
Future cash inflows	$ 889,940	$ 520,976	$ 502,260
Future production costs	(286,197)	(91,675)	(89,246)
Future development costs	(40,023)	(11,551)	(22,294)
Future income tax expense	(96,431)	(72,895)	(87,363)
	467,289	344,855	303,357
10% annual discount factor	(190,822)	(126,436)	(104,345)
Standardized measure of discounted future cash flows	$ 276,467	$ 218,419	$ 199,012
AFRICA			
Oil and gas producing activities:			
Future cash inflows	$ 333,091	$ 713,459	$ 279,896
Future production costs	(75,381)	(212,615)	(95,216)
Future development costs	(14,497)	(261,413)	(26,770)
Future income tax expense	(81,680)	(17,062)	(10,912)
	161,533	222,369	146,998
10% annual discount factor	(23,520)	(98,141)	(16,255)
Standardized measure of discounted future cash flows	$ 138,013	$ 124,228	$ 130,743
TOTAL			
Oil and gas producing activities:			
Future cash inflows	$ 31,344,288	$ 20,252,414	$ 16,494,786
Future production costs	(8,883,850)	(5,978,072)	(4,754,891)
Future development costs (a)	(2,118,766)	(1,598,021)	(998,119)
Future income tax expense	(6,012,779)	(3,309,608)	(2,568,066)
	14,328,893	9,366,713	8,173,710
10% annual discount factor	(7,685,818)	(4,783,460)	(4,047,158)
Standardized measure of discounted future cash flows	$ 6,643,075	$ 4,583,253	$ 4,126,552

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

PIONEER NATURAL RESOURCES COMPANY

UNAUDITED SUPPLEMENTARY INFORMATION
Years Ended December 31, 2004, 2003 and 2002

Changes in Standardized Measure of Discounted Future Net Cash Flows

	Year Ended December 31,		
	2004	2003	2002
		(in thousands)	
Oil and gas sales, net of production costs	$ (1,719,990)	$ (1,136,520)	$ (489,338)
Net changes in prices and production costs	2,082,706	670,165	2,042,575
Extensions and discoveries	302,794	413,777	152,253
Development costs incurred during the period	249,890	202,396	262,469
Sales of minerals-in-place	(14,222)	-	-
Purchases of minerals-in-place	2,058,195	198,442	187,460
Revisions of estimated future development costs	(447,828)	(444,726)	(387,404)
Revisions of previous quantity estimates	140,950	458,468	527,987
Accretion of discount	644,238	514,608	250,033
Changes in production rates, timing and other	(167,400)	(71,557)	99,722
Change in present value of future net revenues	3,129,333	805,053	2,645,757
Net change in present value of future income taxes	(1,069,511)	(348,352)	(1,019,531)
	2,059,822	456,701	1,626,226
Balance, beginning of year	4,583,253	4,126,552	2,500,326
Balance, end of year	$ 6,643,075	$ 4,583,253	$ 4,126,552

PIONEER NATURAL RESOURCES COMPANY

UNAUDITED SUPPLEMENTARY INFORMATION
Years Ended December 31, 2004, 2003 and 2002

Selected Quarterly Financial Results

The following table provides selected quarterly financial results for the years ended December 31, 2004 and 2003:

	Quarter			
	First	Second	Third (a)	Fourth
	(in thousands, except per share data)			
2004:				
Oil and gas revenues	$ 435,527	$ 435,930	$ 441,724	$ 519,482
Total revenues and other income	$ 437,249	$ 437,308	$ 443,151	$ 529,068
Total costs and expenses	$ 337,284	$ 315,847	$ 338,708	$ 375,724
Net income	$ 60,188	$ 69,702	$ 80,916	$ 102,048
Net income per share:				
Basic	$ .51	$ .59	$ .68	$ .71
Diluted	$ .50	$ .58	$ .67	$ .69
2003:				
Oil and gas revenues	$ 273,431	$ 334,077	$ 326,210	$ 340,153
Total revenues and other income	$ 277,570	$ 335,441	$ 326,604	$ 347,804
Total costs and expenses	$ 206,459	$ 255,626	$ 234,686	$ 259,872
Net income:				
Income before cumulative effect of change in accounting principle	$ 68,807	$ 77,185	$ 191,813	$ 57,374
Cumulative effect of change in accounting principle, net of tax	15,413	-	-	-
Net income	$ 84,220	$ 77,185	$ 191,813	$ 57,374
Basic earnings per share:				
Income before cumulative effect of change in accounting principle	$ .59	$ .66	$ 1.64	$ .49
Cumulative effect of change in accounting principle, net of tax	.13	-	-	-
Net income	$ .72	$ .66	$ 1.64	$ .49
Diluted earnings per share:				
Income before cumulative effect of change in accounting principle	$ .58	$ .65	$ 1.62	$ .48
Cumulative effect of change in accounting principle, net of tax	.13	-	-	-
Net income	$ .71	$ .65	$ 1.62	$ .48

(a) The Company's third quarter results for 2003 include a $104.7 million adjustment to reduce United States deferred tax asset valuation allowances. See Note Q for additional information regarding income taxes.

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 principal executive officer and principal financial officer have evaluated, as required by Rule 13a-15(b) under the Securities Exchange Act of 1934 (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 annual report on Form 10-K. 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 Pioneer Natural Resources Company (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, 2004, 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, 2004, 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, 2004. 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, 2004, 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, 2004, 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, 2004, 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, 2004, 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, 2004 and 2003 and the related consolidated statements of operations, stockholders' equity, cash flows and comprehensive income (loss) for each of the three years in the period ended December 31, 2004 of the Company and our report dated February 17, 2005 expressed an unqualified opinion thereon.

Ernst & Young LLP

Dallas, Texas
February 17, 2005

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The information required in response to this item is set forth in the Company's definitive proxystatement for the annual meeting of stockholders to be held on May 11, 2005 and is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION

The information required in response to this item is set forth in the Company's definitive proxy statement for the annual meeting of stockholders to be held on May 11, 2005 and is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

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 information required in response to this item is set forth in the Company's definitive proxy statement for the annual meeting of stockholders to be held on May 11, 2005 and is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The information required by Item 201(d) of Regulation S-K in response to this item is provided in "Item 5. Market for Registrant's Common Stock, Related Stockholder Matters and Issuer Purchases of Equity Securities". The information required by Item 403 of Regulation S-K in response to this item is set forth in the Company's definitive proxy statement for the annual meeting of stockholders to be held on May 11, 2005 and is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required in response to this item is set forth in theCompany's definitive proxy statement for the annual meeting of stockholders to be held on May 11, 2005 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, 2004 and 2003
Consolidated Statements of Operations for the Years Ended December 31, 2004, 2003 and 2002
Consolidated Statements of Stockholders' Equity for the Years Ended December 31, 2004, 2003 and 2002
Consolidated Statements of Cash Flows for the Years Ended December 31, 2004, 2003 and 2002
Consolidated Statements of Comprehensive Income (Loss) for the Years Ended December 31, 2004, 2003 and 2002
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 22, 2005.

(c) Financial Statement Schedules

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

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.pioneernrc.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 11, 2005, 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@pioneernrc.com

INVESTOR RELATIONS/MEDIA CONTACT

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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Kenneth H. Sheffield, Jr., President
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Pioneer Natural Resources Canada Inc.
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Canada
Telephone: (403) 231-3100

Pioneer Natural Resources (Argentina) S.A.
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Hashim Alkhersan, Manager
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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

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

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

James L. Houghton [2,4]
Retired Senior Tax Partner
Ernst & Young L.L.P.

Jerry P. Jones [2,4]
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 L.L.C.

Mark S. Sexton [4]
Director and CEO
Evergreen Energy Company

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 Business Development

Mark S. Berg
Executive Vice President,
General Counsel and Secretary

Chris J. Cheatwood
Executive Vice President,
Worldwide Exploration

Richard P. Dealy
Executive Vice President and
Chief Financial Officer

Danny L. Kellum
Executive Vice President,
Domestic Operations

Marcelo D. Guiscardo
Vice President, International

Thomas C. Halbouty
Vice President and
Chief Information Officer

William F. Hannes
Vice President,
Engineering and Development

Darin G. Holderness
Vice President and
Chief Accounting Officer

Frank E. Hopkins
Vice President, Investor Relations

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

Jay P. Still
Vice President, Western Division

Roger W. Wallace
Vice President, Government Affairs

PIONEER NATURAL RESOURCES

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