XTO ENERGY

A TIMELESS VALUE

ANNUAL REPORT

04

A Timeless Value

Evidence of an ancient Earth is contained in the rocks that form its crust. The rock formations themselves read like pages to a long complicated history. Geologic events scarred the surface and buried ancient life forms layer upon layer. These organic structures – plants and animals dating back perhaps 3 billion years – form the origins of natural resources today.

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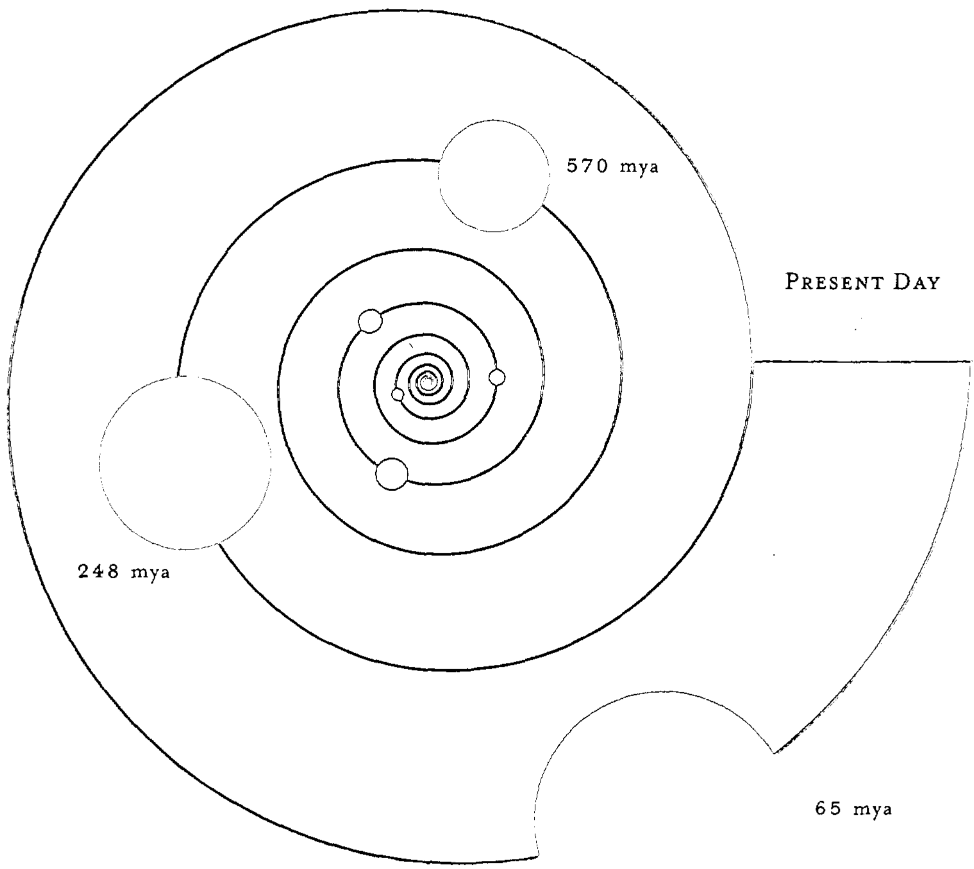
mya = million years ago

Geologic Time Scale



Cenozoic Era:

Powder River Basin, Green River Basin

Mesozoic Era:

Eastern Region, San Juan Basin, Rocky Mountains, South Texas

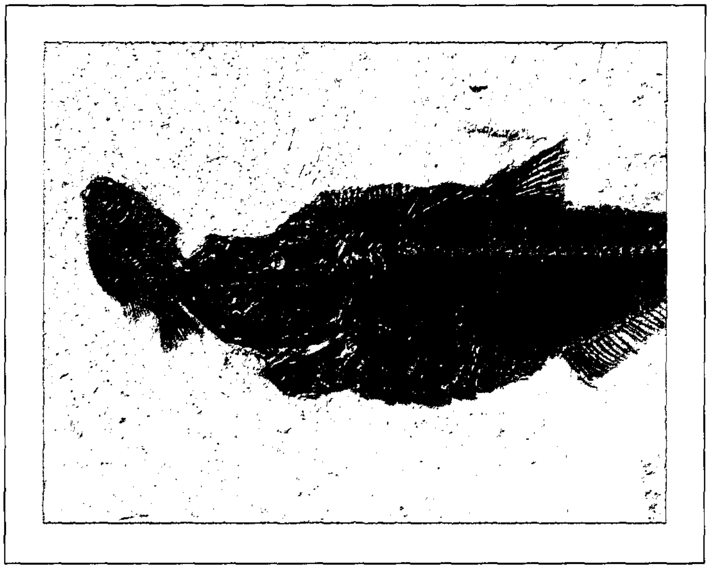
Paleozoic Era:

Permian Basin, Arkoma, Mid-Continent, Barnett Shale

Precambrian Era

04

NYSE: XTO



a). CENOZOIC ERA, EOCENE PERIOD (58-37 mya)

Diplomystus and small Priscara

TABLE *of* CONTENTS

Our founders started XTO Energy in 1986 with a strategy that had proven successful over the previous decade: acquire the best producing properties and make them better. We have held true to this discipline. Long-lived oil and gas basins offer the greatest opportunity to grow because the properties tend to outperform. We combine these assets with employees who also outperform. The end result is a process, a culture and a vision that has prospered in a volatile and sometimes chaotic industry. By staying committed to what we know, XTO Energy delivers the results today even as we build the foundation for future growth. This creates value per share and, in the end, our investment will endure.

	2004	2003	2002	2001	2000
FINANCIAL (in millions, except per share data)					
Total revenues	$ 1,947.6	$ 1,189.6	$ 810.2	$ 838.7	$ 600.9
Operating income	$ 919.3	$ 501.7	$ 348.8	$ 511.0	$ 212.1
Earnings available to common stock	$ 507.9 a	$ 288.3 b	$ 186.1 c	$ 248.8 d	$ 115.2 e
Per common share [f]					
Basic	$ 1.53	$ 0.96 g	$ 0.67	$ 0.91 h	$ 0.49
Diluted	$ 1.51	$ 0.95 g	$ 0.66	$ 0.90 h	$ 0.46
Operating cash flow [i]	$ 1,285.6	$ 792.3	$ 515.9	$ 549.6	$ 344.6
Total assets	$ 6,110.4	$ 3,611.1	$ 2,648.2	$ 2,132.3	$ 1,591.9
Long-term debt	$ 2,042.7	$ 1,252.0	$ 1,118.2	$ 856.0	$ 769.0
Total stockholders' equity	$ 2,599.4	$ 1,465.6	$ 907.8	$ 821.1	$ 497.4
Common shares outstanding at year end [f]	347.2	312.3	282.2	275.0	258.5
PRODUCTION (in thousands, except per unit data)					
Average daily production					
Gas (Mcf)	834.6	668.4	513.9	416.9	343.9
Natural gas liquids (Bbls)	7.5	6.5	5.1	4.4	4.4
Oil (Bbls)	22.7	12.9	13.0	13.6	12.9
Mcfe	1,015.7	784.9	622.5	525.1	448.1
Average sales price					
Gas (per Mcf)	$ 5.04	$ 4.07	$ 3.49	$ 4.51	$ 3.38
Natural gas liquids (per Bbl)	$ 26.44	$ 19.99	$ 14.31	$ 15.41	$ 19.61
Oil (per Bbl)	$ 38.38	$ 28.59	$ 24.24	$ 23.49	$ 27.07
PROVED RESERVES (in millions)					
Gas (Mcf)	4,714.5	3,644.2	2,881.2	2,235.5	1,769.7
Natural gas liquids (Bbls)	38.5	34.7	25.4	20.3	22.0
Oil (Bbls)	152.5	55.4	56.3	54.0	58.4
Mcfe	5,860.3	4,184.9	3,371.9	2,681.6	2,252.4
STOCK PRICE [f]					
High	$ 27.66	$ 17.58	$ 11.87	$ 9.78	$ 8.70
Low	$ 15.35	$ 10.21	$ 6.61	$ 5.54	$ 1.52
Close	$ 26.54	$ 16.98	$ 11.12	$ 7.88	$ 8.33
Cash dividends per share	$ 0.0900	$ 0.0240	$ 0.0180	$ 0.0165	$ 0.0100
Average daily trading volume (in thousands)	2,636	1,917	1,538	2,191	1,840

a Includes pre-tax effects of a derivative fair value loss of $11.9 million, stock-based incentive compensation of $89.5 million and special bonuses totaling $11.7 million related to the ChevronTexaco and ExxonMobil acquisitions. Stock-based incentive compensation includes cash compensation of $22.3 million related to cash-equivalent performance shares.

b Includes pre-tax effects of a derivative fair value loss of $10.2 million, a non-cash contingency gain of $1.7 million, non-cash incentive compensation of $53.1 million, a $9.6 million loss on extinguishment of debt, a $16.2 million non-cash gain on the distribution of Cross Timbers Royalty Trust units, and a $1.8 million after-tax gain on adoption of the accounting standard for asset retirement obligations.

c Includes pre-tax effects of a derivative fair value gain of $2.6 million, gain on settlement with Enron Corporation of $2.1 million, non-cash incentive compensation of $27 million and an $8.5 million loss on extinguishment of debt.

d Includes pre-tax effects of a derivative fair value gain of $54.4 million, non-cash incentive compensation of $9.6 million, and an after-tax charge of $44.6 million for the cumulative effect of accounting change.

e Includes pre-tax effects of a derivative fair value loss of $55.8 million, a gain of $43.2 million on significant asset sales and non-cash incentive compensation expense of $26.1 million.

f Adjusted for the three-for-two stock splits effected on September 18, 2000 and June 5, 2001, the four-for-three stock split effected on March 18, 2003, the five-for-four stock split effected on March 17, 2004 and the four-for-three stock split effected on March 15, 2005.

g Before cumulative effect of accounting change, earnings per share were $0.95 basic and $0.94 diluted.

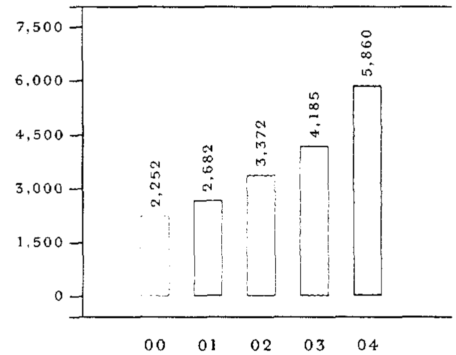
h Before cumulative effect of accounting change, earnings per share were $1.08 basic and $1.06 diluted.

i Defined as cash provided by operating activities before changes in operating assets and liabilities and exploration expense. See Non-GAAP Measures on page 30.

Glossary is located on page 30.

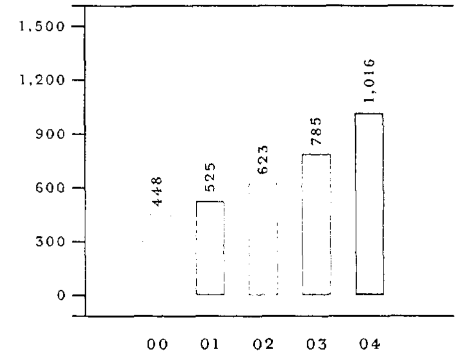
PROVED RESERVES

(in Bcfe)



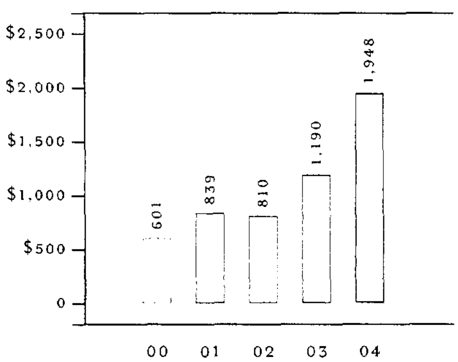
DAILY PRODUCTION

(in MMcfe)



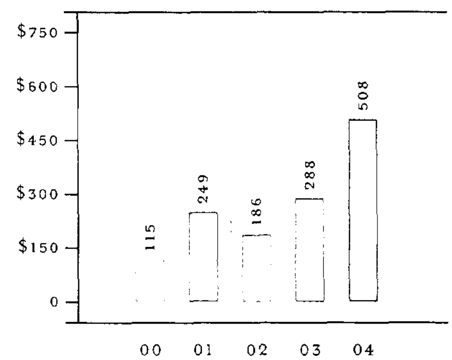
TOTAL REVENUES

(in millions)



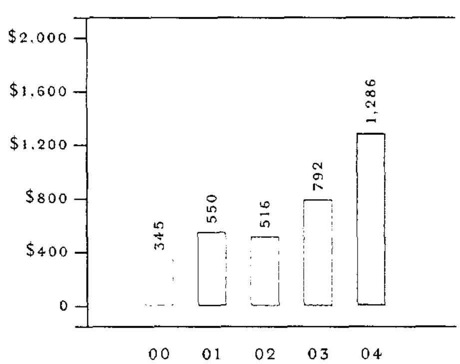
NET INCOME

(in millions)



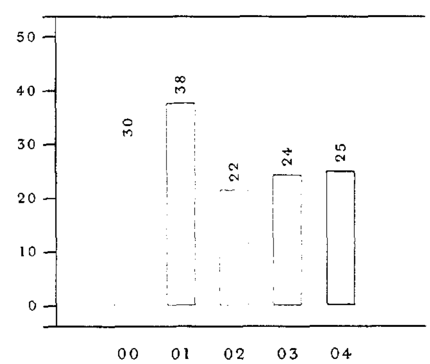
OPERATING CASH FLOW

(in millions)



RETURN ON EQUITY

(%)



Fellow Shareholders:

As a start-up in 1986 with a handful of employees, we envisioned building a solid energy company, one well at a time. Nearly two decades later, XTO Energy continues to achieve beyond even our expectations. Today, the Company owns almost 1 billion barrels of oil equivalent. Daily production has topped 1 Bcfe and more than 1,350 people call XTO home. Perhaps most important for our owners today, XTO has amassed a premier property base that tends to generate better results with time.

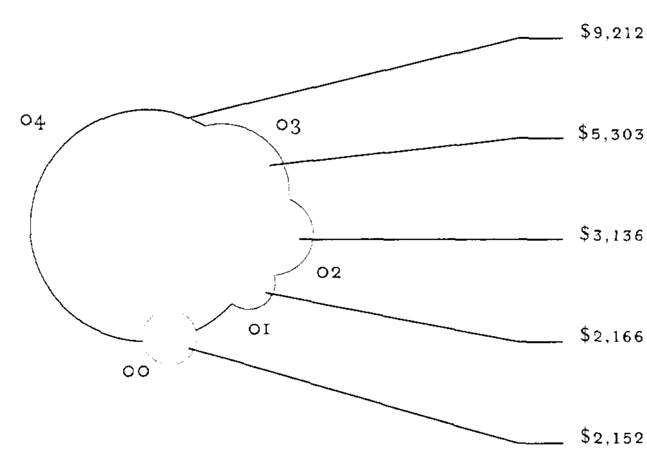
As we close the books on 2004, we are proud to announce another extraordinary year of performance for XTO Energy. In fact, it was a record year across the board. The Company achieved record earnings, cash flow, production and reserves. Reflecting these achievements, the stock price reached a record high during the year. While stronger commodity prices are generating solid results industrywide, we believe the foundation of XTO, the acquisition and development of high-grade producing properties, continues to distinguish our accomplishments year after year.

The Company's notable achievements for 2004 include:

- Record operating cash flow totaled $1.29 billion, up 62%.
- Net income per share increased 59% to a record $1.53 per basic common share.
- Daily equivalent production averaged 1.02 Bcfe, an increase of 29%.
- Record producing property acquisitions totaled $1.95 billion, adding 1.32 Tcfe of long-lived reserves.
- Proved reserves grew 40% to 5.86 Tcfe.

MARKET CAPITALIZATION

(year-end in millions)



At about 1 Bcf per day *of* gas production, can you continue to grow?

Of course. Our management of the key ingredients: growing a rich low-risk drilling inventory, maintaining a shallow decline curve and carefully pacing development programs should ensure resilient growth.

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- From all sources, we replaced 551% of 2004 production at an all-in finding cost of $1.26 per Mcfe.
- With drilling alone, we replaced 195% of annual production at a cost of $0.88 per Mcfe.
- The Company achieved 'investment grade' credit status.
- XTO was added to the S&P 500.
- Finally, the market value of XTO increased 74% to $9.2 billion during the year.

XTO Energy has emerged in the energy sector as a large capitalization company. Today, our enterprise value is above $13 billion and daily gas volumes represent almost 2% of overall domestic production. But size is only significant if the underlying business stays effective, profitable and dynamic. The good news is that XTO has never been better positioned. As evidenced by our operational success and record acquisitions, the strategy remains focused and potent. Our low-cost, high-margin production is driving record capital returns and a powerful balance sheet. Our hand-picked properties continue to deliver predictable growth. So, the direction going forward is established and the momentum is robust. As the Company enters 2005, the prospects for another record-setting year look promising.

Designed for Long-Term Profitable Growth

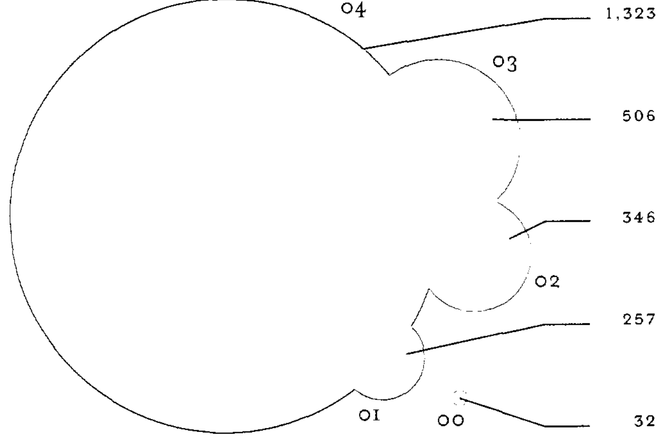
In our view, predictable growth is the key for any successful franchise. To encourage hard work and then attract meaningful investment, a company needs a plan that provides visibility for the future. We find it important to discuss XTO's growth agenda every year because we work in a depleting asset business. Steep production declines in America and fewer impact plays make it challenging to keep domestic production flat, in either natural gas or oil. The dilemma raises doubts for every investor. If a company must constantly drill its way to growth, the challenge is daunting: more wells to drill, more exploration and thus, increasing risk.

XTO's unique quality is that we start our growth profile with acquisitions that generally do not suffer dramatic production declines. Then, from within these properties, we define drilling upsides and deliver growth at a measured pace. With this balanced approach, the Company has grown production and reserves per share each year since going public in 1993. Even more important, the growth has consistently generated healthy full-cycle economics. Our return on equity and return on capital b). Mesozoic Era, Cretaceous Period (144-65 mya)

Keichousaurus

The process of growth and change continues in the natural world today. But along the way, it has also been permanently frozen in time. The reptile at left, fossilized in 100 million-year-old shale, represents a species forever in the making.

ACQUISITION RESERVES
(Bcfe)



employed have averaged 28% and 14%, respectively, over the past five years. Ultimately, our low-risk development programs and low-cost property base are driving substantial amounts of free cash. Today, less than one-third of cash flow is required to maintain our production levels. The remaining two-thirds is available for additional development drilling, acquisitions or return to shareholders. Regardless, with so much financial firepower, 'organic growth' – growth through the Company's free cash flow – should be inevitable. We believe this economic strength distinguishes XTO within the industry. It also assures a steady pace of continuing growth for our shareholders.

Each year, a prime objective is to generate more drilling inventory worthy of our capital dollars. Low-risk opportunities optimize our growth trajectory. For XTO, these captured drilling opportunities continue to increase even as the Company has scaled-up in size. In 2004, exploitation activities expanded upsides throughout the core operating regions. In conjunction, the impact of our successful acquisition campaign brought exciting new prospects in our Eastern Region, the Permian Basin, the Rocky Mountains and the Barnett Shale of North Texas. XTO Energy now boasts an inventory of up to 3,850 new well locations which are slated for development. Put into perspective, these low-risk wells provide another 4 to 5 years of drilling visibility. The unbooked reserve potential of 3 Tcfe implies upsides of more than 50% to the Company's proven reserve base.

With this in mind, we have targeted production growth of 21% to 23% in 2005. For 2006, our initial production growth, based on a conservative drilling pace and before acquisitions, is projected at 10%. As our track record reveals, we plan to judiciously use this inventory to keep growing for years to come.

Achieving Record Acquisitions at the Right Time

At XTO Energy, acquiring the right properties is where value creation takes root. Our team has spent its collective career working to identify and own the right reservoir rock in America. For us, these properties are characterized by specific traits:

1). Long producing histories defined by substantial well data,

2). Highly complex reservoirs in which to apply operational and technological innovations,

3). Extensive resource potential embedded in sedimentary basins, and

XTO has always been a premium buyer. We expect to increase acquired reserves by 50% to 100% and generate healthy economic returns along the way. With higher commodity prices, quality acquisitions are simply worth more.

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4). Old-fashioned high-margin economics to weather the cycles.

Over time, we have seen that these assets tend to outperform even our projections. Since inception of the Company in 1986, we have purchased 4.5 Tcfe and increased those volumes by another 3.8 Tcfe, including production and reserve additions. This means that our efforts have increased reserves on the average XTO acquisition by 85% through the effectiveness of our long-term development programs.

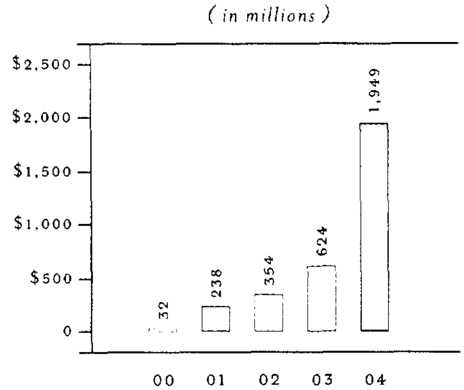
Because it's half of our business, we pursue acquisitions for the right reason: we know the rock and believe that we can make it perform better. So, we stay focused on the pursuit of acquisitions that offer XTO this opportunity. Our team is working to craft deals with the Majors, independents and private players. We also solicit assets that are not for sale. This ongoing endeavor creates a pipeline of potential acquisitions that may take years to come to fruition.

In 2004, our dealmaking efforts achieved new heights, establishing XTO as a preferred partner to the Majors. We purchased a record 1.3 Tcfe of reserves for about $1.95 billion, overwhelming our 2003 record of $624 million. At a price of $1.47 per Mcfe, these deals look highly attractive in a market that today commands around $2 per Mcfe. All told, our team completed over 140 separate transactions adding property interests from Louisiana to the northern Rockies.

The majority of the purchases during the year came from ChevronTexaco and ExxonMobil. Totaling almost $1.3 billion, these deals delivered both oil and natural gas production in quality fields with underlying production declines below 10% and significant

PRODUCING PROPERTY ACQUISITIONS

(in millions)



c). Paleozoic Era, Mississippian Period (360-325 mya)

Crinoid

The More Things Stay the Same

The oceans are teeming with creatures whose ancestry spans the eons, yet whose basic design remains virtually unchanged. Despite their names, these sea lilies are actually marine animals. They spend their lives attached to driftwood and stones on the sea floor — just as they have since the Paleozoic.

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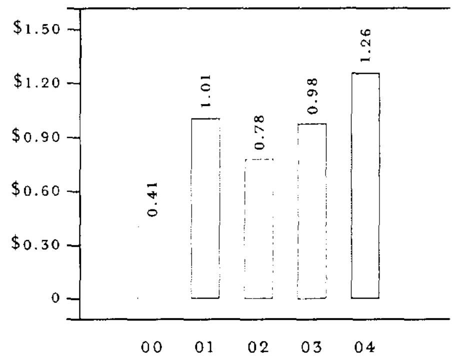
ALL-IN RESERVE REPLACEMENT COST

(dollars per Mcfe)

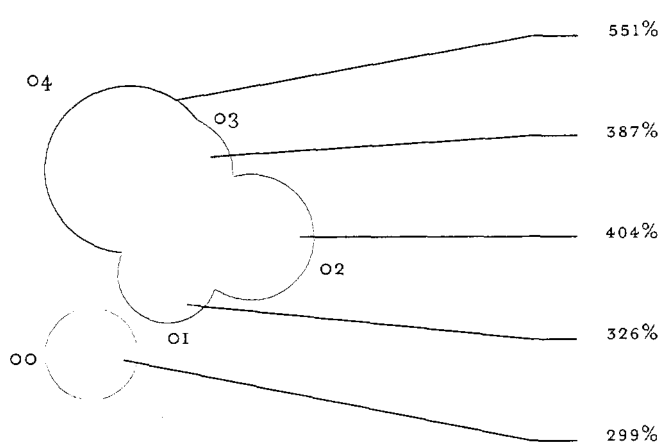


upsides in place. They are the ideal complement to XTO's growth profile. From ChevronTexaco, we bought 732 Bcfe for $930 million. Half oil, these properties expanded XTO's footprint in the Permian Basin and doubled our daily oil production. The assets also brought fresh additions to our Eastern Region, added a coal bed methane operation in the Uinta Basin and established a foothold in South Texas. From ExxonMobil, we increased our West Texas oil holdings with additional interests in existing XTO fields or fields that predominantly offset our successful development programs. We also acquired the Hartzog Draw Unit in Wyoming, marking our entry into the Powder River Basin with a premier oil property complete with coal bed methane upsides. Daily production from the ExxonMobil purchase was about 6,600 barrels of oil. Proved reserves totaled 38 million barrels of oil equivalent. With a renewed focus of expertise and a fresh injection of capital, our team foresees years of development opportunities from these properties.

Moving into 2005, our acquisition efforts remain in high gear. In January, we announced an agreement to purchase privately held Antero Resources Corporation, solidifying our position in the Barnett Shale play of North Texas. For $685 million, XTO committed to purchase 440 Bcfe of natural gas reserves with net daily production of 60 MMcf. This transaction, which closes April 1, elevates our Company to the second largest producer in the Barnett Shale for all the right reasons. The holdings are anchored in the shale's core area where well data and production history have established a solid outlook for a long-term development play. Importantly, strong economic returns are competitive with the robust inventory throughout the Company.

ALL-IN RESERVE REPLACEMENT RATIO

(%)



WHY CAN'T OTHERS *in the* INDUSTRY DUPLICATE YOUR PROCESS?

We have the best talent and we stay committed to what we know. We work hard at the rock. We work hard at finding a technical advantage. We work even harder at keeping our advantage; no distractions.

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Our leadership in this dynamic play provides yet another venue for future growth.

Further acquisition opportunities in 2005 are being pursued. With a strong commodity backdrop, a unique situation has developed. Higher energy prices continue to bring quality assets to market. In our view, Majors will likely rationalize more assets through divestitures, trades and farm-outs. Independents and private owners, limited by manpower and capital, continue to cash out. Given our financial flexibility, XTO is poised to benefit from this scenario.

FORGING AHEAD WITH A DYNAMIC PROPERTY BASE

The XTO advantage is our intense focus on exploiting a basin's full resource potential. We demand complex reservoirs in need of new technology and a fresh perspective. Importantly, we are not distracted with other agendas: no exploration department and no international division competing for capital allocation. In our perspective, the U.S. is embedded with tremendous untapped resources. This trapped oil and gas awaits the right combination of science, technology and innovation to unleash its potential. At XTO, we empower a team of 140 geoscientists and hundreds of seasoned operational veterans to make this happen.

These efforts have placed us in some of the most dynamic resource plays in the industry today. While others look to capture the growth and economic advantages of a single basin play, XTO has managed to aggregate multiple platforms. By virtue of its complexity, XTO is a leader in tight-gas technology and production. We are prominent in the other unconventional production areas, both coal bed methane and shale gas. With our engineering expertise in West Texas, we are committed to enhancing oil recovery in the great oil properties of the Permian Basin. The bottom-line is that our captured upsides should provide steady drilling activity, predictable growth and robust economics for years to come.

o Tight-Gas Properties

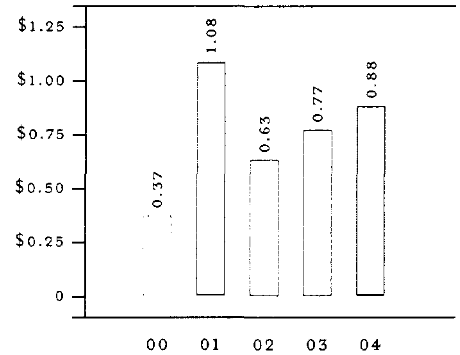
More than 60% of our current gas production, or about 600 MMcf per day, comes from tight-gas formations. The dominant focus of this activity is within our Eastern Region operations. Since the initial acquisition in 1998, net daily production has grown from 80 MMcf to 480 MMcf. The Freestone Trend remains one of our crown jewels with about 325 MMcf in net daily production and 1.9 Tcfe of recognized reserves. Our application of d). PALEOZOIC ERA, PENNSYLVANIAN PERIOD (325 to 286 mya)

Neuropteris

In ancient forests, an abundance of flora and fauna provided the medium that would be transformed into rich organic deposits. This material later became trapped between layers of rock and was eventually buried deep beneath the earth's ever-changing surface.

DRILL BIT RESERVE REPLACEMENT COST

(dollars per Mcfe)



water-fracturing and commingling techniques has tapped several thousand feet of hydrocarbon-rich sediments that had remained undeveloped. This trend 'discovery', which has grown to 166,500 net acres, will continue to act as the swing-producer for the Company. On a conservative development inventory of 1,100 to 1,300 additional wells, we estimate net reserve potential at 2.6 Tcfe. Expanding pipeline infrastructure will increase gross daily capacity 62%, from 450 MMcf to 730 MMcf, and will be completed in the first half of 2005. So, the plan for future growth is set. Our success in the Freestone Trend inspired us to establish positions in two other areas with the same sequence of tight-gas sands: the Sabine Uplift Trend of East Texas and the Cotton Valley Trend of northwestern Louisiana. Our 2005 development program targets increasing growth activities in both of these trends.

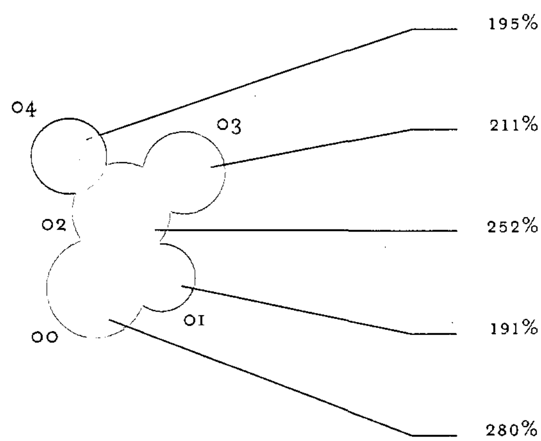
Ongoing tight-gas operations in the Arkoma and San Juan basins will also continue to generate opportunities for future development. XTO's 'fault block analysis technique' in Arkoma has provided a manufacturing-type approach to the region. Through advanced logging techniques and rigorous geological interpretation, we find untapped reservoirs, drill a successful well, identify offset locations and then repeat the process. Deeper, tighter zones, like the Paradox formation of the San Juan Basin, are providing new well locations with more than 2 Bcf of potential.

o Coal Bed Methane Properties

In 1997, the Company acquired its first CBM production in the Fruitland Coal play of the San Juan Basin. As in all our programs, we first initiated a pilot study to evaluate the coal seam properties, commence development and

DRILL BIT RESERVE REPLACEMENT RATIO

(%)



assess well performance. Since that time, our development and acquisition programs have increased daily production from 2 MMcf to about 90 MMcf. Given this success, our special projects team researched coal basins across the U.S. to identify prospective regions that would fit our demanding technical and economic criteria. Acquisitions to date have expanded our CBM positions well beyond the prolific Fruitland Coal to footholds in the Raton, Uinta and Powder River basins. Altogether, the Company has grown daily production to about 135 MMcf and has identified more than 400 development locations. For XTO, the long-lived production profile of CBM assets merges ideally into our program of decline curve management. With extensive drilling opportunities, we anticipate enhancing our coal seam gas production while pursuing broader basin exposure.

o Shale Gas Properties

Since our entry into the Barnett Shale in early 2004, enthusiasm for the challenging, long-lived play has only accelerated. Well performance, reservoir characteristics and continued improvement of completion techniques have confirmed that ultimate gas recovery, particularly in the core-area, will be greater than current expectations. We solidified our commitment to the play with the acquisition of a key producer, Antero Resources, announced in January of 2005. XTO Energy will now direct development of approximately 150,000 net acres across the basin, 50% of which is considered to be in the core-area. This provides XTO with upside potential of more than 1 Tcfe. Tighter spacing and re-fracturing opportunities could substantially increase these upsides over time. With post-closing daily gross production

e). Paleozoic Era, Ordovician Period (505 to 438 mya)

Trilobites

A simple crustacean offers a textbook example of evolution's amazing subtlety. Over thousands of millennia, the environment slowly shapes each species. It is only when we retrace the steps that dramatic changes become apparent.

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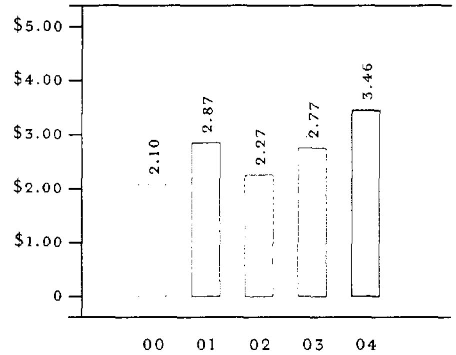
OPERATING CASH FLOW MARGIN

(dollars per Mcfe)



above 130 MMcf, XTO will rank as the second largest producer in the play. We anticipate doubling this production rate by year-end 2006 through an aggressive drilling program. As a hometown producer in the Fort Worth Basin, we envision a decade of development opportunities from the Barnett Shale that should complement our Eastern Region growth activities. At 4 to 6 million acres of potential coverage and only 10% developed, the best is yet to come for this shale play.

Beyond North Texas, our team is assessing shale potential across America. Due to its sizeable acreage holdings in Arkansas, the Company has a position in the Fayetteville Shale play in the Arkoma Basin. We plan to gauge its viability throughout the course of 2005.

Our Proven Strategy Delivers Strong Results

Once again, the Company surpassed benchmarks set just a year ago. Total production grew almost 29% with natural gas increasing 25% to 835 MMcf per day, oil growing by 75% to about 22,700 barrels per day and natural gas liquids up 16% to 7,500 barrels per day. With higher volumes and strong commodity prices, total revenues for XTO hit a record $1.95 billion, besting the 2003 mark of $1.19 billion. Operating cash flow increased to about $1.29 billion, up 62% from the prior year level. Equally important, reported earnings hit $508 million, or $1.53 per share, compared to $0.96 per share in 2003.

Our powerful capital investment program continues to fuel XTO's prosperity. In 2004, we added 2.05 Tcfe of reserves for a total of $2.59 billion. This implies an all-in finding cost of $1.26 per Mcfe, excluding asset retirement obligations of $0.03 per Mcfe. With an operating cash flow margin per Mcfe of $3.46, XTO was able to add 2.7 Mcfe for each Mcfe produced, a leading reinvestment efficiency for the sector. The Company continues to generate one of the lowest drill bit finding costs in the domestic energy complex. For a cost of $0.88 per Mcfe, our development program added 724 Bcfe of reserves, holding true to our historic replacement ratio of about 200%. Overall, XTO Energy's proven reserves increased 40% from year ago levels, to 5.86 Tcfe. Under SEC guidelines, these reserves quantities reflect a present value before income tax, discounted at 10%, of $12.2 billion. As always, since 1986, the outside engineering firm Miller & Lents, Ltd. has prepared the reserve report for the Company.

With so much inventory, why not drill faster?

Our full-cycle exploitation process takes time. With a disciplined timeframe, we can maximize returns, generate upsides and acquire more. Our goal is to balance present value realizations with future growth value.

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Reiterating Our 'Stronger for Longer' Posture

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Simply put, the outlook for robust energy prices endures. Since 2000, oil has averaged almost $31 per barrel while natural gas has exceeded $4.50 per Mcf. Importantly, prices have trended ever higher over the past few years culminating in today's prices of about $54 oil and $7 gas on the NYMEX. Market conjecture is contentious regarding the source and sustainability of these levels. Experts and investors alike discuss geopolitical fears, the OPEC agenda, the Chinese economic blitz, our strained global supply situation – and the list goes on. From our perspective, these higher price levels are grounded in solid fundamentals. Supply and demand are precariously balanced, with demand gradually gaining the upper hand.

On the global oil outlook, with about 82 million barrels per day of capacity, the overhang of supply has finally evaporated. Production in America and the North Sea is declining. The potential of the former Soviet Union nations has peaked in the short term and even OPEC has pushed the limit with only marginal heavy and sour oil remaining in its inventory. Finally, the entire energy complex is showing the fatigue of more than a decade of systemic under-investment. At the same time, global inventories appear to be caught at a low point. New fields and updated industry infrastructure are years away; thus, no quick fix is on the horizon.

Meanwhile, demand for petroleum products continues to grow. Energy consumption grinds upwards in the U.S. as the economy moves ahead. Booming economies in the Far East and Asian sub-continent have accelerated over the past three years, with China's hyper-growth blazing the way. Projections place global oil needs at close to 84 million barrels per day by year end 2005. The daunting outlook for supply and demand makes a 'squeeze' unavoidable.

The scenario for natural gas in North America is equally challenging. Domestic production in 2004 decreased by another 3%, bringing the 3-year loss to above 5 Bcf per day. Even record levels of drilling activity have failed to offset the estimated 25% annual decline in underlying production. Exploration risks have accelerated. Meanwhile, the major integrated companies are directing their efforts to the international arena because of the dearth of sizeable prospects in U.S. basins. Moving forward, the fix for natural gas supplies appears to be liquid natural gas, which is also a vital global commodity facing f). PALEOZOIC ERA, DEVONIAN PERIOD (408 to 360 mya)

Eurypterids

Adapt and Survive

Under the sea, some species seem protected from the constant tide of change. The lobster has adapted little over time, with its success largely due to the same traits it has possessed for ages. Their design has made for an efficient creature capable of a wide variety of functions.

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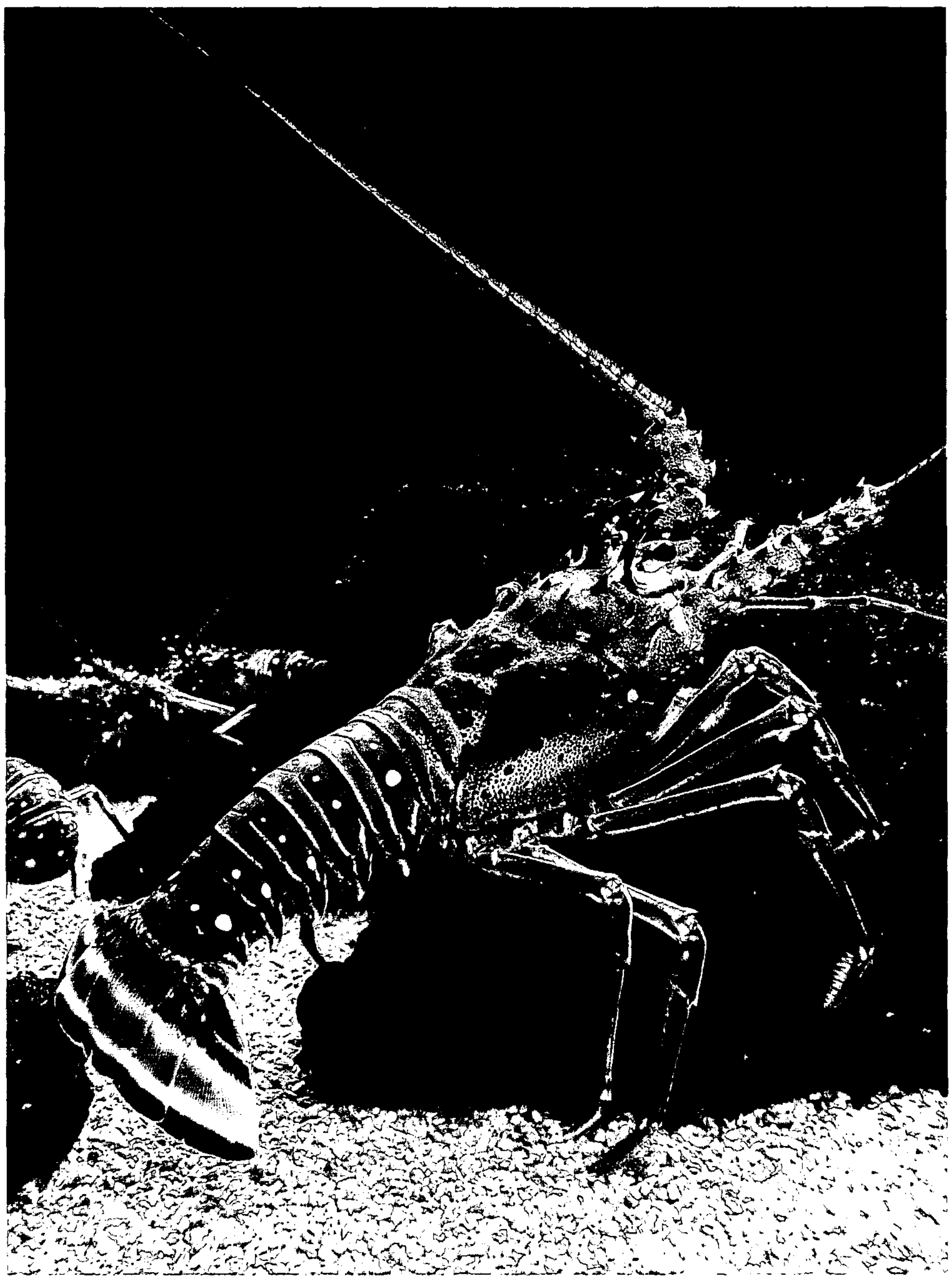
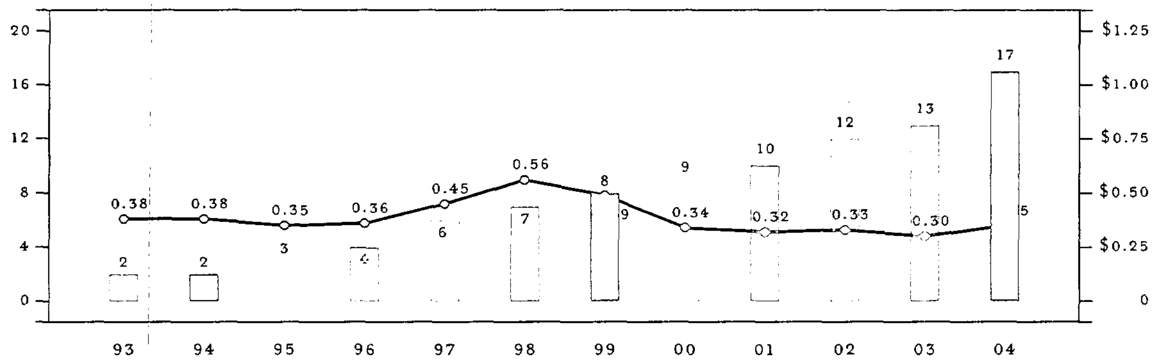


VALUE CREATION

(bars = Mcfe/share line = debt/Mcfe)



increasing demand. LNG will need to be imported in larger quantities to bridge the gap. So today, the behavior in the natural gas markets reflects 'scarcity'. With any anomalies in weather or economic growth, prices are poised to spike again.

All things considered, we believe energy commodities have entered an era of higher prices with continued volatility. Unlike the economic effects of the 1970's, these higher energy prices do not appear to be accelerating inflation and promoting recession. Just the opposite is true. Abroad, emerging nations are devouring commodities at any price to support economic expansion, with the weak U.S. dollar helping their cause. At home, increased efficiencies have cut the real cost of energy for the average consumer to about half the level endured two decades ago. Therefore, more expendable income is available to buffer higher energy costs in our personal pocket-books and in the national economy.

As we move forward into 2005, economists peg global economic growth at about 4%. This contends that the demand for energy should move higher, resulting in energy prices remaining strong. In our view, this 'stronger for longer' posture is a prerequisite for attracting new investment in production and for rationalizing surging demand. Regardless, we believe the days of cheap energy appear to be behind us, while a new, decade-long cycle is upon us. If so, energy companies are set for prolonged prosperity, leading to better valuations in the markets and ultimately, higher stock prices.

Executing on Our Value Creation Strategy

In this supercharged energy environment, XTO is positioned to continue to deliver extraordinary results. The Company's growth projections point toward another year of record production and reserves. Our financial performance is also poised for records in both earnings and cash flow. So, the directive to our team is to stay the course. Maintain discipline in deploying capital. Be diligent in pursuing the right acquisitions to build for the future. And most important, stay focused on creating value for investors. As founders and shareholders, our fundamental principle has been to consistently grow reserves and production per share as we sustain or improve the relative debt level. As illustrated in the graph above, our long-lived proved reserves have increased about 10 times per share since the IPO, reflecting a compounded annual growth rate of about 23%. Importantly, the intrinsic value

The strategy works, but can you scale-up the culture?

We plan for it everyday. Growth provides opportunity. Prosperity provides compelling compensation. And, as founders, we keep the entrepreneurial spirit alive.

of each reserve unit has more than doubled over the same period, from $1 to above $2 today. This simple measure of net asset value has tracked well with our stock price performance which had increased by about 23 times through year-end 2004. Understanding this value creation framework establishes confidence in our plan for the future. Given the Company's current upside development inventory, long-lived production base and free-cash firepower, we can generate profitable growth and create value. In absolute terms, we believe this translates into multiple years of double-digit growth ahead for XTO.

With experience as our guide, we have always considered our strategy both successful and enduring. We had hoped that as an investment XTO would prove timeless. The future will tell, but we are proud of our progress thus far.

As always, we thank our Board of Directors for their stewardship and dedication. We applaud our employees for their hard work and late hours. For our shareholders, we remain committed to building solid underlying value at XTO. . . one well at a time.

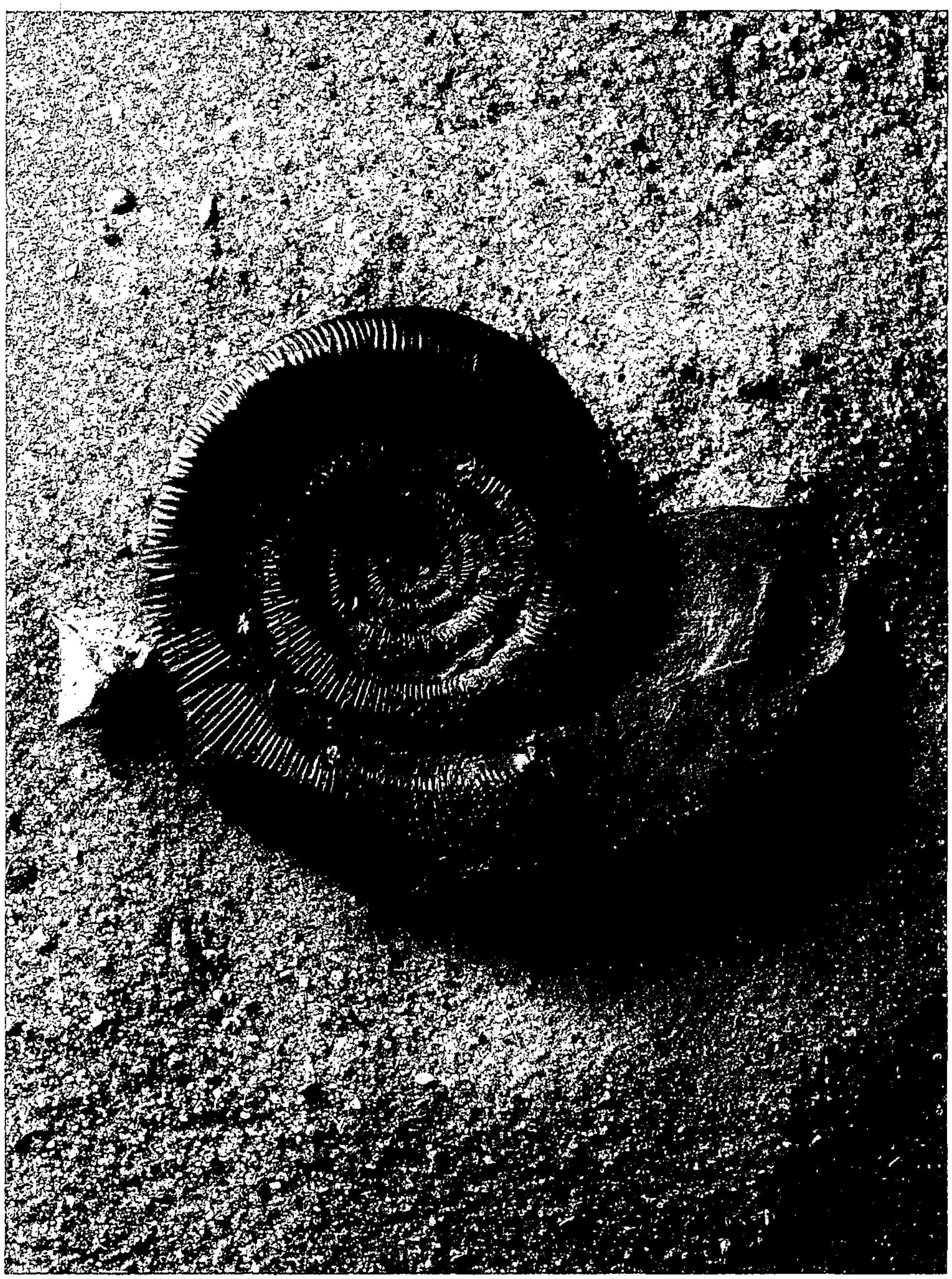
BOB R. SIMPSON
Chairman and Chief Executive Officer

STEFFEN E. PALKO
Vice Chairman and President

March 31, 2005

g). Mesozoic Era, Jurassic Period (208-144 mya)

Ammonite



Shelled cephalopods were the dominant predators of the seas until their disappearance at the end of the Cretaceous period. Today, while there are many species of invertebrates still alive in the world's oceans, the Chambered Nautilus is the only one with an external shell that resembles that of its ancestor — the ammonite.

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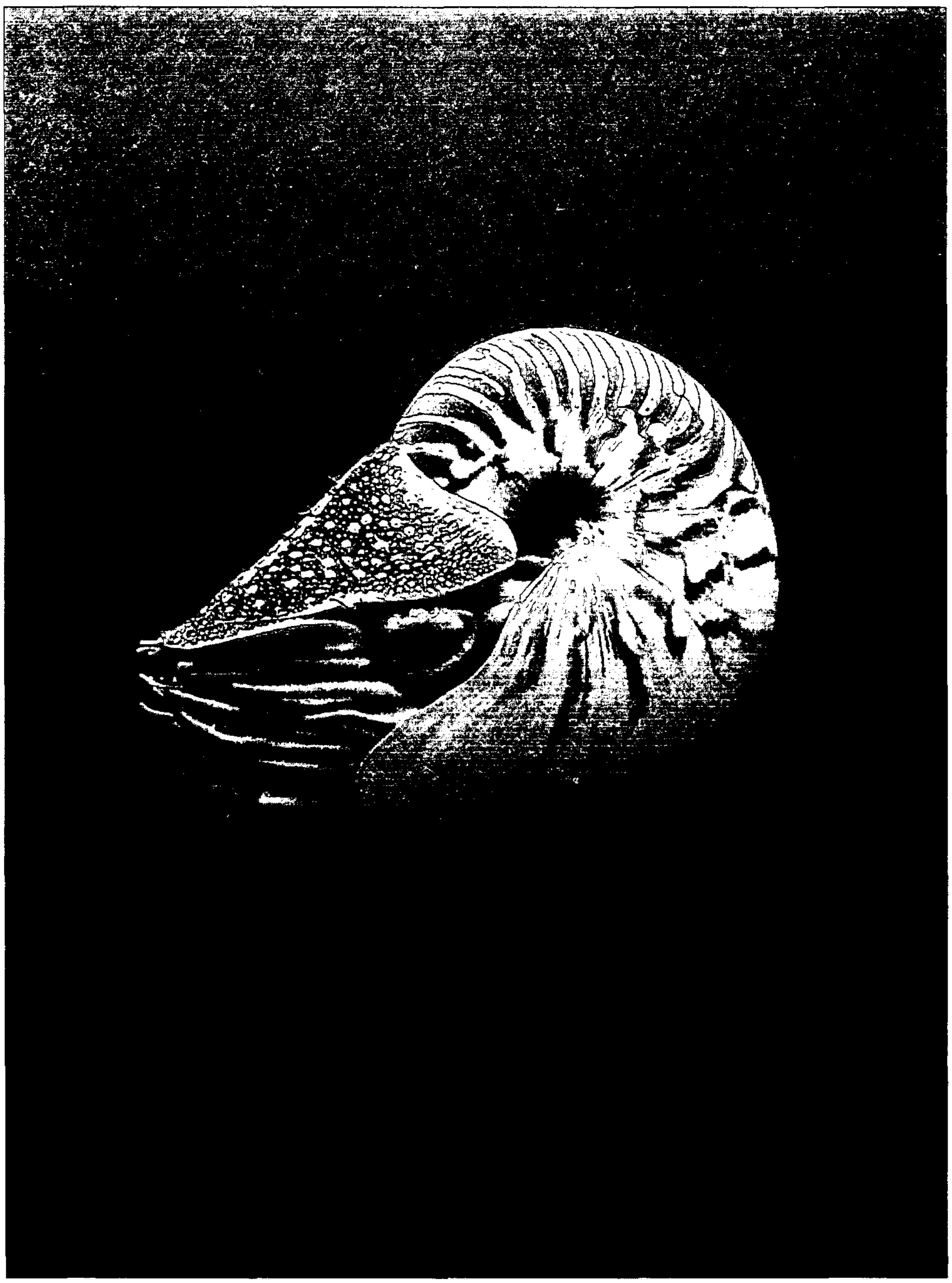

o Non-GAAP Measures

The following terms are considered non-GAAP measures as defined by the Securities and Exchange Commission. Management uses these measures to evaluate the Company's performance versus the performance of other oil and gas producing companies, as well as to evaluate potential acquisitions.

All-in Finding Costs

Total costs incurred [a], excluding the asset retirement obligation accrual. For purposes of evaluating annual costs incurred, management excludes the asset retirement obligation accrual since these estimated costs are related to future activities, and are deducted in the calculation of estimated future net cash flows of proved reserves.

All-in Reserves

The total of proved reserve extensions, additions and discoveries, purchases in place and revisions [a,b]

All-in Reserve Replacement Cost

All-in Finding Costs divided by All-in Reserves

All-in Reserve Replacement Ratio

All-in Reserves divided by production [a,b]

Drill Bit Finding Costs

The total of costs incurred for development, exploration and acquisitions of undeveloped properties [a]

Drill Bit Reserves

The total of proved reserve extensions, additions and discoveries and revisions [a,b]

Drill Bit Reserve Replacement Cost

Drill Bit Finding Costs divided by Drill Bit Reserves

Drill Bit Reserve Replacement Ratio

Drill Bit Reserves divided by production [a,b]

Free Cash Flow

Operating Cash Flow less total maintenance and development expenditures required to maintain current production levels

Operating Cash Flow

Cash provided by operating activities before changes in operating assets and liabilities and exploration expense. Because of exclusion of changes in operating assets and liabilities and exploration expense, this cash flow statistic is different from cash provided by operating activities, as is disclosed under GAAP and reconciled to operating cash flow as follows:

(in millions)	2004	2003	2002	2001	2000
Cash provided by operating activities	$ 1,216.9	$ 794.2	$ 490.8	$ 542.6	$ 377.4
Changes in operating assets and liabilities	58.2	(3.7)	22.9	1.5	(33.8)
Exploration expense	10.5	1.8	2.2	5.5	1.0
Operating cash flow	$ 1,285.6	$ 792.3	$ 515.9	$ 549.6	$ 344.6

Management believes that operating cash flow is a better liquidity indicator for oil and gas producers because of the adjustments made to cash provided by operating activities, explained as follows:

- Adjustment for changes in operating assets and liabilities eliminates fluctuations primarily related to the timing of cash receipts and disbursements, which can vary from period-to-period because of conditions the Company cannot control (for example, the day of the week on which the last day of the month falls), and results in attributing cash flow to operations of the period that provided the cash flow.
- Adjustment for exploration expense is to provide an amount comparable to operating cash flow for full cost companies and to eliminate the effect of a discretionary expenditure that is part of the Company's capital budget.

Operating Cash Flow Margin

Operating Cash Flow divided by production [a,b]

Upsides or Potential Reserves

Reserves beyond proved reserves [a], which includes probable and possible reserves that are potentially recoverable through additional drilling or recovery techniques. Only proved reserves are disclosed in financial statements prepared in accordance with GAAP, and SEC guidelines prohibit disclosure of these potentially recoverable reserves in filings with the SEC. Management believes it is appropriate to disclose these potentially recoverable reserves in certain communications with investors to provide reserve estimates associated with our inventory of future drill well locations.

a As disclosed in Note 15 to Consolidated Financial Statements
b As calculated on a natural gas equivalent (Mcfe) basis

Bbls	1,000 barrels (of oil or NGLs)	MBbl	Thousand barrels (of oil or NGLS)	ROCE	Ratio of net income before interest and taxes divided by average total capital employed for the period
Bcf	Billion cubic feet (of gas)	MMBOE	Million barrels of oil equivalent	ROE	Ratio of net income divided by average stockholders' equity for the period
Bcfe	Billion cubic feet equivalent	Mcf	Thousand cubic feet (of gas)	ROR	Discount rate at which cash flows equal initial investment
BOE	Barrels of oil equivalent	Mcfe	Thousand cubic feet equivalent	Tcfe	Trillion cubic feet equivalent
BOPD	Barrels of oil per day	MMcf	Million cubic feet (of gas)		
CBM	Coal bed methane	MMcfe	Million cubic feet equivalent		
LNG	Liquified natural gas	NGLs	Natural gas liquids		

One barrel of oil is the energy equivalent of six Mcf of natural gas.

2004

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 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: 1-10662

XTO ENERGY INC.

(Exact name of registrant as specified in its charter)

Delaware	75-2347769	810 Houston Street, Fort Worth, Texas	76102
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)	(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code (817) 870-2800

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, $.01 par value, including preferred stock purchase rights	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 be 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. [X]

Indicate by checkmark whether the registrant is an accelerated filer (as defined in Exchange Act Rule 12b-2).
Yes [X] No [ ]

Aggregate market value of the Common Stock based on the closing price on the New York Stock Exchange as of June 30, 2004 (the last business day of its most recently completed second fiscal quarter), held by nonaffiliates of the Registrant on that date was approximately $7.3 billion.

Number of Shares of Common Stock outstanding as of February 25, 2005 (as adjusted for the four-for-three stock split to be effected March 15, 2005) - 347,389,307

DOCUMENTS INCORPORATED BY REFERENCE
(To The Extent Indicated Herein)

XTO ENERGY INC.

2004
ANNUAL REPORT ON FORM 10-K

TABLE *of* CONTENTS

PART I

Items 1 and 2

BUSINESS *and* PROPERTIES

o GENERAL

XTO Energy Inc. and its subsidiaries ("the Company") are engaged in the acquisition, development, exploitation and exploration of producing oil and gas properties, and in the production, processing, marketing and transportation of oil and natural gas. The Company was formerly known as Cross Timbers Oil Company and changed its name to XTO Energy Inc. in June 2001.

On February 15, 2005, our Board of Directors declared a four-for-three stock split to be effected on March 15, 2005. All common stock shares and per share amounts in this Form 10-K have been retroactively restated for the effect of this stock split.

Our corporate internet web site is www.xtoenergy.com. We make available free of charge, on or through the investor relations section of our web site, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission.

We have grown primarily through strategic acquisitions of proved oil and gas reserves, followed by development and exploitation activities and acquisition of additional interests in or near such acquired properties. We expect growth in the immediate future to continue to be accomplished through a combination of acquisitions and development. During 2005, we plan to continue to review strategic acquisition opportunities including property divestitures by major energy related companies, public exploration and development companies and private energy companies. Completion of additional acquisitions will depend on the quality of properties available, commodity prices and competitive factors.

Our corporate headquarters are located in Fort Worth, Texas at 810 Houston Street (telephone 817-870-2800). Our proved reserves are principally located in relatively long-lived fields with well-established production histories concentrated in the following areas:

- Eastern Region, including the East Texas Basin and northwestern Louisiana;
- Barnett Shale of North Texas;
- San Juan and Raton basins of northern New Mexico and southern Colorado;
- Arkoma Basin of Arkansas and Oklahoma;
- Permian Basin of West Texas and southeastern New Mexico;
- Hugoton Field of Oklahoma and Kansas;
- Anadarko Basin of Oklahoma;
- Green River and Powder River basins of Wyoming;
- Uinta Basin of Utah;
- Middle Ground Shoal Field of Alaska's Cook Inlet; and
- South Texas Region.

We use the following volume abbreviations throughout this Form 10-K. "Equivalent" volumes are computed with oil and natural gas liquid quantities converted to Mcf, or natural gas converted to Bbls, on an energy equivalent ratio of one barrel to six Mcf.

– Bbl	Barrel (of oil or natural gas liquids)
– Bcf	Billion cubic feet (of natural gas)
– Bcfe	Billion cubic feet equivalent
– BOE	Barrels of oil equivalent
– Mcf	Thousand cubic feet (of natural gas)
– Mcfe	Thousand cubic feet equivalent
– MMBtu	One million British Thermal Units, a common energy measurement

– Tcf Trillion cubic feet (of natural gas)

– Tcfe Trillion cubic feet equivalent

Our estimated proved reserves at December 31, 2004 were 4.71 Tcf of natural gas, 38.5 million Bbls of natural gas liquids and 152.5 million Bbls of oil, based on December 31, 2004 prices of $5.69 per Mcf for gas, $28.24 per Bbl for natural gas liquids and $41.03 per Bbl for oil. On an energy equivalent basis, our proved reserves were 5.86 Tcfe at December 31, 2004, a 40% increase from proved reserves of 4.18 Tcfe at the prior year end. Increased proved reserves during 2004 were primarily the result of acquisitions and development and exploitation activities. On an Mcfe basis, 72.3% of proved reserves were proved developed reserves at December 31, 2004 . During 2004, our average daily production was 834,572 Mcf of gas, 7,484 Bbls of natural gas liquids and 22,696 Bbls of oil. Fourth quarter 2004 average daily production was 915,905 Mcf of gas, 8,628 Bbls of natural gas liquids and 33,494 Bbls of oil.

Our properties have relatively long reserve lives and highly predictable production profiles. Based on December 31, 2004 proved reserves and projected 2005 production from properties owned as of December 31, 2004, the average reserve-to-production index of our proved reserves is 15.1 years. In general, these properties have extensive production histories and production enhancement opportunities. While the properties are geographically diversified, the major producing fields are concentrated within core areas, allowing for substantial economies of scale in production and cost-effective application of reservoir management techniques gained from prior operations. As of December 31, 2004, we owned interests in 18,104 gross (8,455.8 net) producing wells, and we operated wells representing 88% of the present value of cash flows before income taxes (discounted at 10%) from estimated proved reserves. The high proportion of operated properties allows us to exercise more control over expenses, capital allocation and the timing of development and exploitation activities in our fields.

We have a substantial inventory of between 3,100 and 3,850 potential development drilling locations. Drilling plans are primarily dependent upon product prices, the availability and pricing of drilling equipment and supplies, and gathering, processing and transmission infrastructure.

We employ a disciplined acquisition program refined by senior management to expand our reserve base in core areas and to add new core areas. Our engineers and geologists use their expertise and experience gained through the management of existing core properties to target properties to be acquired with similar geological and reservoir characteristics.

We operate gas gathering systems in several of our core producing areas. We also operate gas processing plants in East Texas, the Hugoton Field and the Cotton Valley Field of Louisiana. Our gas gathering and processing operations are only in areas where we have production and are considered activities that facilitate our natural gas production and sales operations.

We market our gas production and the gas output of our gathering and processing systems. A large portion of our natural gas is processed, and the resultant natural gas liquids are marketed by unaffiliated third parties. We use fixed-price physical sales contracts and futures, forward sales contracts and other price risk management instruments to hedge pricing risks.

○ HISTORY OF THE COMPANY

The Company was incorporated in Delaware in 1990 to ultimately acquire the business and properties of predecessor entities that were created from 1986 through 1989. Our initial public offering of common stock was completed in May 1993.

During 1991, we formed Cross Timbers Royalty Trust by conveying a 90% net profits interest in substantially all of the royalty and overriding royalty interests that we then owned in Texas, New Mexico and Oklahoma, and a 75% net profits interest in seven nonoperated working interest properties in Texas and Oklahoma. Cross Timbers Royalty Trust units are listed on the New York Stock Exchange under the symbol "CRT." From 1996 to 1998, we purchased 1,360,000, or 22.7%, of the outstanding units, at a total cost of $18.7 million. In August 2003, our Board of Directors declared a dividend of 0.0044 units of the trust for each share of our common stock outstanding on September 2, 2003. As a result of this dividend, all of the 1,360,000 trust units were distributed on September 18, 2003.

In December 1998, we formed the Hugoton Royalty Trust by conveying an 80% net profits interest in principally gas-producing operated working interests in the Hugoton area of Kansas and Oklahoma, the Anadarko Basin of Oklahoma and the Green River Basin of Wyoming. These net profits interests were conveyed to the trust in exchange for 40 million units of beneficial interest. We sold 17 million units in the trust's initial public offering in 1999 and 1.3 million units pursuant to an employee incentive plan in 1999 and 2000. We own the remaining 54% of the units, which we account for as producing properties. Hugoton Royalty Trust units are listed on the New York Stock Exchange under the symbol "HGT."

○ INDUSTRY OPERATING ENVIRONMENT

The oil and gas industry is affected by many factors that we generally cannot control. Governmental regulations, particularly in the areas of taxation, energy and the environment, can have a significant impact on operations and profitability. Crude oil prices are determined by global supply and demand. Oil supply is significantly influenced by production levels of OPEC member countries, while demand is largely driven by the condition of worldwide economies, as well as weather. Natural gas prices are generally determined by North American supply and demand. Weather has a significant impact on demand for natural gas since it is a primary heating resource. Its increased use for electrical generation has kept natural gas demand elevated throughout the year, removing some of the seasonal swing in prices. See "Significant Events, Transactions and Conditions – Product Prices" in Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, regarding recent price fluctuations and their effect on our results.

○ BUSINESS STRATEGY

The primary components of our business strategy are:

- acquiring long-lived, operated oil and gas properties, including undeveloped leases,
- increasing production and reserves through aggressive management of operations and through development, exploitation and exploration activities,
- hedging a portion of our production to stabilize cash flow and protect the economic return on development projects and acquisitions, and
- retaining management and technical staff that have substantial experience in our core areas.

Acquiring Long-Lived, Operated Properties. We seek to acquire long-lived, operated producing properties that:

- contain complex multiple-producing horizons with the potential for increases in reserves and production,
- produce from non-conventional sources, including tight natural gas reservoirs, coal bed methane and natural gas-producing shale formations,
- are in core operating areas or in areas with similar geologic and reservoir characteristics, and
- present opportunities to reduce expenses per Mcfe, and lower the rate of potential increases to expenses per Mcfe, through more efficient operations.

We believe that the properties we acquire provide opportunities to increase production and reserves through the implementation of mechanical and operational improvements, workovers, behind-pipe completions, secondary recovery operations, new development wells and other development activities. We also seek to acquire facilities related to gathering, processing, marketing and transporting oil and gas in areas where we own reserves. Such facilities can enhance profitability, reduce costs, and provide marketing flexibility and access to additional markets. The ability to successfully purchase properties is dependent upon, among other things, competition for such purchases and the availability of financing to supplement internally generated cash flow.

We also seek to acquire undeveloped properties that potentially have the same attributes as targeted producing properties.

Increasing Production and Reserves. A principal component of our strategy is to increase production and reserves through aggressive management of operations and low-risk development. We believe that our principal properties possess geologic and reservoir characteristics that make them well suited for production increases through drilling and other development programs. We have generated an inventory of between 3,100 and 3,850 potential drilling locations. Additionally, we review operations and mechanical data on operated properties to determine if actions can be taken to reduce operating costs or increase production. Such actions include installing, repairing and upgrading lifting equipment, redesigning downhole equipment to improve production from different zones, modifying gathering and other surface facilities and conducting restimulations and recompletions. We may also initiate, upgrade or revise existing secondary recovery operations.

Exploration Activities. During 2005, we plan to focus our exploration activities on projects that are near currently owned productive fields. We believe that we can prudently and successfully add growth potential through exploratory activities given improved technology, our experienced technical staff and our expanded base of operations. We have allocated approximately $30 million of our $850 million 2005 development budget for exploration activities.

Hedging Activities. To reduce production price risk, we enter futures contracts, collars and basis swap agreements, as well as fixed price physical delivery contracts. Our policy is to routinely hedge a portion of our production. While there is a risk we may not be able to realize the full benefit of rising prices, management plans to continue its hedging strategy because of the benefits provided by predictable, stable cash flow, including:

- ability to more efficiently plan and execute our development program, which facilitates predictable production growth,
- ability to help assure the economic return on strategic acquisitions,
- ability to enter long-term arrangements with drilling contractors, allowing us to continue development projects when product prices decline,
- more consistent returns on investment, and
- better utilization of our personnel.

Experienced Management and Technical Staff. Most senior management and technical staff have worked together for over 20 years and have substantial experience in our core operating areas. Bob R. Simpson and Steffen E. Palko, co-founders of the Company, were previously executive officers of Southland Royalty Company, one of the largest U.S. independent oil and gas producers prior to its acquisition by Burlington Northern, Inc. in 1985.

Other Strategies. We may also acquire working interests in nonoperated producing properties if such interests otherwise meet our acquisition criteria. We attempt to acquire nonoperated interests in fields where the operators have a significant interest to protect, including potential undeveloped reserves that will be exploited by the operator. We may also acquire nonoperated interests in order to ultimately accumulate sufficient ownership interests to operate the properties.

We also attempt to acquire a portion of our reserves as royalty interests. Royalty interests have few operational liabilities because they do not participate in operating activities and do not bear production or development costs.

Royalty Trusts and Publicly Traded Partnerships. We have created and sold units in publicly traded royalty trusts. Sales of royalty trust units allow us to more efficiently capitalize our mature, lower-growth properties. We may create and distribute or sell interests in additional royalty trusts or publicly traded partnerships in the future.

Business Goals. In January 2005, we announced a strategic goal for 2005 of increasing production by 21% to 23% over 2004 levels. To achieve this growth target, we plan to drill about 735 (560 net) development wells and perform approximately 540 (400 net) workovers and recompletions in 2005.

We have budgeted $850 million for our 2005 development program, which is expected to be funded by cash flow from operations. We plan to spend $400 million in the Eastern Region of East Texas and northwestern Louisiana, $170 million in the Barnett Shale of North Texas, $85 million in the Raton, San Juan and Uinta basins, $85 million for programs in the Permian Basin, and $80 million in the Arkoma Basin and Mid-Continent Region. We expect to spend $30 million for exploration.

While an acquisition budget has not been formalized, we plan to actively review additional acquisition opportunities during 2005. If acquisition, development and exploration expenditures exceed cash flow from operations, we expect to obtain additional funding through our bank credit facilities, issuance of public or private debt or equity, or asset sales. Strategic property acquisitions during 2005 may alter the amount currently budgeted for development and exploration. Our total budget for acquisitions, development and exploration will be adjusted throughout 2005 to focus on opportunities offering the highest rates of return. We also may reevaluate our budget and drilling programs in the event of significant changes in oil and gas prices. Our ability to achieve production goals depends on the success of our planned drilling programs or property acquisitions made in place of a portion of the drilling program.

The weak U.S. dollar, raw material shortages and strong global demand for steel have continued to tighten steel supplies and cause prices to remain high. In response, we have increased our tubular inventory and have negotiated supply contracts with our vendors to support our development program. While we expect to acquire adequate supplies to complete our development program, a further tightening of steel supplies could restrain the program, limiting production growth and increasing development costs.

ACQUISITIONS

During 2001, we acquired predominantly gas-producing properties for a total cost of $242 million. In January 2001, we acquired gas properties in East Texas and Louisiana for $115 million from Herd Producing Company, Inc., and in February 2001, we acquired gas properties in East Texas for $45 million from Miller Energy, Inc. and other owners. In August 2001, we acquired primarily underdeveloped acreage in the Freestone area of East Texas for approximately $22 million. The 2001 acquisitions increased reserves by approximately 248.3 Bcf of natural gas, approximately 50% of which were proved undeveloped.

During 2002, we acquired gas-producing properties for a total cost of $358.1 million. In May 2002, we acquired properties in the Powder River Basin of Wyoming for $101 million. These properties were immediately exchanged with Marathon Oil Company for properties with the same value in East Texas and Louisiana. In July, we purchased gas-producing properties in the San Juan Basin of New Mexico for $43 million and in December 2002, we purchased coal bed methane gas-producing properties located in the San Juan Basin of New Mexico for $153.8 million from J.M. Huber Corporation. The 2002 acquisitions increased reserves by approximately 330.4 Bcf of natural gas, 2.2 million Bbls of natural gas liquids and 449,000 Bbls of oil. Approximately 10% of these reserves were proved undeveloped.

During 2003, we acquired gas-producing properties for a total cost of $629.5 million. In April 2003, we acquired natural gas and coal bed methane producing properties in the Raton Basin of Colorado, the Hugoton Field of southwestern Kansas and the San Juan Basin of New Mexico and Colorado for $381 million from Williams of Tulsa, Oklahoma. In June 2003, we acquired coal bed methane and gas-producing properties in the San Juan Basin of New Mexico and Colorado from Markwest Hydrocarbon, Inc. for $51 million. In October 2003, we announced the completion of property transactions which increased our positions in East Texas, Arkansas and the San Juan Basin of New Mexico for a total cost of $100 million. The 2003 acquisitions increased reserves by approximately 465.7 Bcf of natural gas, 4.5 million Bbls of natural gas liquids and 2.2 million Bbls of oil. Approximately 12% of these reserves were proved undeveloped.

During 2004, we acquired producing properties for a total cost of $1.9 billion. In January 2004, we acquired producing properties in East Texas and northwestern Louisiana for $243 million from multiple parties. From February through April, we purchased $223.1 million of properties located primarily in the Barnett Shale of North Texas and in the Arkoma Basin. Two of these acquisitions were purchases of corporations that primarily owned producing and nonproducing properties. Purchase accounting adjustments related to these acquisitions included a $72.3 million deferred income tax step-up adjustment. During April, we acquired predominantly oil-producing properties in the Permian Basin of West Texas and in the Powder River Basin of Wyoming from ExxonMobil Corporation for $336 million, including a contingent payable of up to $5 million dependent on earnings from one property in the following year. In August, we acquired properties from ChevronTexaco Corporation for a purchase price of $930 million, as adjusted for subsequent purchase of properties that were subject to preferential purchase rights. These properties expand our operations in our Eastern Region, the Permian Basin and Mid-Continent Region and add new coal bed methane properties in the Rocky Mountains and a new operating region in South Texas. All 2004 acquisitions are subject to typical post-close adjustments. Our 2004 acquisitions increased reserves by approximately 716.5 Bcf of natural gas, 2.9 million Bbls of natural gas liquids and 98.2 million Bbls of oil. Approximately 18% of these reserves were proved undeveloped.

In January 2005, we announced an agreement to purchase privately held Antero Resources Corporation, a prominent Barnett Shale producer, for cash and equity consideration valued at approximately $685 million. Consideration includes $337.5 million in cash, 13.3 million shares of our common stock and five-year warrants to purchase another 2 million shares of our common stock at $27 per share. The purchase agreement was amended in February 2005 to include Antero's gas gathering assets and related bank debt of $175 million. The transaction is expected to close April 1, 2005. The booked acquisition cost will include customary non-cash adjustments, including a step-up adjustment for deferred income taxes. The cash consideration for the acquisition will be initially provided through cash flow from operations and existing bank credit facilities.

SIGNIFICANT PROPERTIES

The following table summarizes proved reserves and discounted present value, before income tax, of proved reserves by major operating areas at December 31, 2004:

(IN THOUSANDS)	PROVED RESERVES GAS (MCF)	NATURAL GAS LIQUIDS (BBLS)	OIL (BBLS)	NATURAL GAS EQUIVALENTS (MCFE)	DISCOUNTED PRESENT VALUE BEFORE INCOME TAX OF PROVED RESERVES	
Eastern Region	2,523,826	4,791	8,117	2,601,274	$ 5,442,885	44.5%
San Juan Basin and Rocky Mountain Area	895,802	33,266	12,442	1,170,050	2,253,065	18.4%
Permian Basin and South Texas Region	240,613	399	108,764	895,591	2,019,883	16.5%
Arkoma Basin and Mid-Continent Region	651,624	–	5,010	681,684	1,529,162	12.5%
Hugoton Royalty Trust (a)	281,506	–	2,405	295,936	573,865	4.7%
North Texas Region	117,546	–	23	117,684	205,381	1.7%
Alaska Cook Inlet	–	–	14,986	89,916	197,221	1.6%
Other	3,586	–	759	8,140	15,587	0.1%
Total	4,714,503	38,456	152,506	5,860,275	$ 12,237,049	100.0%

(a) Includes 192,719,000 Mcf of gas and 1,647,000 Bbls of oil and discounted present value before income tax of $403,441,000 related to our ownership of approximately 54% of Hugoton Royalty Trust units at December 31, 2004. The remainder is our retained interests in the properties underlying the trust's net profits interests.

Eastern Region

We began operations in the East Texas area in 1998 with the purchase of 251 Bcfe of reserves in eight major fields. These properties are located in East Texas and northwestern Louisiana and produce primarily from the Rodessa, Travis Peak, Cotton Valley sandstone, Bossier sandstone and Cotton Valley limestone formations between 7,000 feet and 13,000 feet. During 2004, we increased our position in the Eastern Region with the purchase of 102 Bcfe of proved reserves in Franklin, Freestone, Limestone and Anderson counties of Texas and Claiborne Parish of Louisiana. Development in the East Texas area has more than doubled reserves since we began operations, and we now have an interest in more than 375,000 gross (258,000 net) acres and a current development inventory of 1,450 to 1,700 wells. We own an interest in 1,935 gross (1,726.5 net) wells that we operate and 447 gross (72.1 net) wells operated by others. We also own the related gathering facilities. In 2004, we expanded our gathering system to more than 600 miles and our treating capacity to more than 700,000 Mcf per day.

Freestone Trend

The Freestone Trend area is located in the western shelf of the East Texas Basin in Freestone, Robertson, Limestone and Leon counties. This area includes the Freestone, Bald Prairie, Bear Grass, Oaks, Teague, Farrar, Dew and Luna fields and was our most active gas development area in 2004, where 185 gross (166.1 net) gas wells were drilled and 14 workovers were performed. In 2004, we increased our acreage position to 225,000 gross (166,500 net) acres in this area and have a development inventory of 1,100 to 1,300 wells. Initial development was concentrated in the Travis Peak formation, but is now focused on multi-pay development of the deeper horizons, including the Cotton Valley and Bossier sandstones and Cotton Valley limestone. We plan to continue our expansion efforts in this area by drilling approximately 175 wells and performing about 26 workovers in 2005. In 2002, we completed a 27-mile pipeline system that connects the major fields and allows multiple exit points for marketing. During 2004, we continued expansion of the pipeline and gathering systems with the completion of an amine plant and a sour treating facility. We plan to complete an additional sour treating facility during the first half of 2005. These improvements have increased our pipeline capacity to over 700,000 Mcf per day. We will continue to construct and operate infrastructure or contract additional pipeline capacity to support our drilling activity.

Other Eastern Region Fields

Other fields in the Eastern Region include the Opelika, Willow Springs, Whelan, Oak Hill and Carthage fields in the East Texas area and the Middlefork, Oaks/Colquitt, Cotton Valley and Logansport fields in northwestern Louisiana. With our 2004 acquisitions, we increased our position in these areas, which provides opportunities for field extensions and infill drilling. In 2004, we drilled 37 gross (27.0 net) wells and performed 22 workovers in the other Eastern Region fields. In 2005, we plan to drill ten wells in the Carthage area, 27 wells in northwestern Louisiana and 25 wells in various fields and perform 28 workovers and recompletions. As a part of our 2002 acquisition from Marathon, we acquired an interest in a Cotton Valley gas plant that we now operate. This plant processes approximately 38,000 Mcf of gas per day and extracts 1,825 Bbls of natural gas liquids per day, primarily from the surrounding operated wells.

North Texas Region

Barnett Shale

The Barnett Shale is the largest natural gas field in Texas and covers 15 counties. Our operations in the Barnett Shale began in January 2004 with the acquisition of 118 Bcfe of reserves. We have continued to expand our acreage positions and, by year end, had leased more than 80,000 net acres and identified 250 to 300 potential drilling locations. We drilled 20 gross (18.4 net) wells in 2004, ten of which were horizontal wells. In January 2005, we announced the acquisition of Antero Resources Corporation, including 440 Bcfe of proved reserves and a gas gathering system. This acquisition will make us the second largest producer in the Barnett Shale and will increase our net acreage holdings to 148,000 acres. We plan to drill 120 to 130 Barnett Shale wells in 2005.

San Juan Basin and Rocky Mountain Area

Our San Juan Basin and Rocky Mountain Area includes properties in the San Juan and Raton basins of New Mexico and Colorado, as well as properties in the Powder River Basin of Wyoming and the Uinta Basin of Utah. We have now identified 575 to 775 potential drilling locations to develop these complex, multi-pay basins where we own an interest in 1,892 gross (1,625.2 net) operated wells and 2,337 gross (286.4 net) wells operated by others.

San Juan Basin

The San Juan Basin of northwestern New Mexico and southwestern Colorado contains the largest deposit of natural gas reserves in North America. Our San Juan Basin drilling has focused on the Fruitland Coal formation at shallow intervals of 3,000 feet or less and the Mesaverde and Dakota formations at depths of 3,000 to 7,500 feet. We own an interest in 1,194 gross (990.0 net) wells that we operate and 2,288 gross (279.8 net) wells operated by others. In 2004, we participated in the drilling of 102 gross (71.8 net) wells and completed 177 workovers. During 2005, we plan to drill up to 75 wells and perform approximately 200 workovers and recompletions, including installation of as many as 70 wellhead compressors and 130 pumping units.

Raton Basin

In 2003, we acquired natural gas and coal bed methane properties in the Raton Basin of Colorado. The Raton Basin is characterized by shallow prolific coal bed methane production, low development cost, available gas market access points and significant development opportunities. Producing formations include the Raton Coals at depths of 500 to 1,800 feet and the Vermejo Coals at depths of 800 to 2,500 feet. We own an interest in 238 gross (237.9 net) wells that we operate. We drilled 38 gross (38.0 net) wells and performed ten workovers in this area in 2004 and plan to drill 20 wells and perform 30 workovers in 2005.

Rocky Mountains

Hartzog Draw Unit. During 2004, we acquired a 78.6% working interest in this 35,000 acre unit in northeastern Wyoming from ExxonMobil. We have initiated a program to optimize secondary recovery operations and drill additional wells. In the Powder River Basin, coal bed methane development from the shallow Fort Union coal bed zones (Big George), delineated under 12,500 net acres, offers immediate opportunities for new production and reserves. We drilled 31 gross (10.0 net) wells in 2004. We plan to drill approximately 25 to 50 wells and perform 67 workovers in this area in 2005.

Uinta Basin. During 2004, as a part of our ChevronTexaco acquisition, we expanded our coal bed methane operations with the purchase of 67 Bcfe of proved reserves in the Buzzard Bench Field of Emery County, Utah. This property in the Ferron sand and coal play is an offset to the Drunkard's Wash Field. We have identified 100 to 150 potential well locations in this area where we own an interest in 93 gross (70.3 net) operated wells and 5 gross (1.3 net) wells operated by others. We drilled three gross (2.5 net) wells in 2004 and plan to drill 15 wells in 2005.

Permian Basin and South Texas Region

Permian Basin

During 2004, we acquired approximately 80 million BOE of proved reserves in 16 counties in the Permian Basin of West Texas and New Mexico from ChevronTexaco. Primary producing fields in the area include Yates, Goldsmith, Eunice Monument, Fullerton and Puckett. We have a development inventory of between 475 and 575 potential well locations where we plan to use our secondary recovery expertise to enhance operations and expand development opportunities. We also purchased from ExxonMobil operated interests in the Wasson, Russell, Champmon and Bruce fields and nonoperated working interests in the Flanagan and Wasson fields.

Yates Field. The Yates Field, discovered in 1926, is located in southeastern Pecos County, Texas. We own nonoperated interests in 442 gross (127.8 net) wells, and most production is from the San Andres formation. Results have been improved using carbon dioxide injection and horizontal sidetrack wells. In 2005, the operator plans to drill approximately 110 horizontal sidetrack wells.

Goldsmith Field. The Goldsmith Field, located in Ector County, Texas, is a multi-pay zone field including production from the San Andres, Upper and Lower Clearfork, Devonian and Ellenburger formations at depths ranging from 4,000 to 9,000 feet. The field consists of multiple waterflood units in the Clearfork formation and adjacent units are currently being developed on 10 to 20-acre spacing. We plan to drill 17 wells and perform 30 workovers in this area in 2005.

Russell Field. As a result of acquiring additional working interests from ExxonMobil in 2004, we now have a working interest in excess of 97% in most of our Russell Field wells. Producing formations include the Devonian and Clearfork, as well as exploration potential in the Ellenburger and Granite Wash formations. We drilled seven gross (6.8 net) wells in 2004 and began a 3-D seismic study in February 2005. We plan to drill approximately 21 wells and perform 30 workovers in this area in 2005.

University Block 9 Field. The University Block 9 Field is in Andrews County, Texas. We own interests in 81 gross (77.3 net) operated wells. Productive zones include the Wolfcamp, Pennsylvanian and Devonian. Development potential includes proper wellbore utilization, recompletions, infill drilling and waterflood improvement. We drilled four gross (4.0 net) wells in 2004 and performed four workovers. During 2005, we plan to drill up to 13 wells.

Prentice Field. The Prentice Field is in Terry and Yoakum counties, Texas, and produces from the Clearfork and Glorieta formations. This field has been separated into several waterflood units for secondary recovery operations. Development potential exists through infill drilling and waterflood improvement. We operate the Prentice Northeast Unit, where we have a 91.6% working interest in 216 wells. We also own interests in 71 gross (2.9 net) nonoperated wells. During 2004, we continued our 10-acre development program by drilling nine gross (8.2 net) vertical wells and performing two workovers. We plan to continue our expansion of the potential infill area by drilling as many as ten wells in 2005.

Wasson Field. The Wasson Field is in Gaines and Yoakum counties, Texas, and produces from the San Andres formation. We acquired the Mahoney lease in 2004 from ExxonMobil and became operator. This property is being carbon dioxide flooded and recent development has included fracturing and restimulation. The Cornell Unit has development potential that exists through infill drilling and waterflood improvement. We increased our working interest in this unit to 99.8% in 2004 as a result of the ExxonMobil acquisition. In 2004, we drilled three gross (2.1 net) 10-acre infill oil wells and three gross (2.1 net) gas cap wells in the Cornell Unit, and in 2005 we plan to drill 15 oil wells and two gas cap wells.

South Texas Region

We acquired 54 Bcfe of proved reserves in nine South Texas counties as a part of our 2004 ChevronTexaco acquisition. The Fashing Field, located in Atascosa County, primarily produces from the Edwards Limestone reservoir at depths ranging from approximately 10,000 to 11,000 feet. We have identified 20 to 40 potential well locations in this region and plan to drill six wells in 2005.

Arkoma Basin and Mid-Continent Region

The Arkoma Basin extends from central Arkansas into southeastern Oklahoma and is known for low production decline rates, multiple formations and complex geology. We control 40% of Arkansas production from the Arkoma Basin and are the largest natural gas producer in the state with over 600,000 gross acres of leasehold. With the addition of our leasehold acreage in eastern Oklahoma, we have interests in approximately 800,000 gross acres in the Arkoma Basin. We own an interest in 1,261 gross (895.9 net) wells which we operate and 982 gross (169.5 net) wells operated by others. Our fault-block analysis technique has identified trapped hydrocarbons in offsetting and new reservoirs across the basin. During 2004, we drilled 98 gross (51.7 net) wells and completed 43 workovers, 17 of which were stimulation/recompletions and four of which were wellhead compressor installations. We plan to drill approximately 56 wells and perform up to 55 workovers in 2005.

Hugoton Royalty Trust

A substantial portion of properties in western Oklahoma, the Hugoton area and the Green River Basin of the Rocky Mountains are subject to an 80% net profits interest conveyed to the Hugoton Royalty Trust as of December 1998. We sold 45.7% of our Hugoton Royalty Trust units in 1999 and 2000.

Western Oklahoma

We are one of the largest producers in the Major and Woodward counties, Oklahoma area of the Anadarko Basin. We operate 575 gross (489.6 net) wells and have an interest in 139 gross (36.6 net) wells operated by others. Development in Major County focuses on mechanical improvements, restimulations and recompletions to shallower zones and development drilling. During 2004, we participated in the drilling of 12 gross (8.6 net) wells in the northwestern portion of the county, targeting the Mississippian and Chester formations, and performed eight workovers. We plan to drill eight wells and perform ten workovers in Major County during 2005. We also drilled 12 gross (9.5 net) Chester formation wells in Woodward County. In 2005, we plan to drill up to ten wells and to perform as many as five workovers.

We operate a gathering system and pipeline in the Major County area. The system collects gas from over 400 wells through 300 miles of pipeline. Current throughput is approximately 15,000 Mcf per day, 70% of which is produced from Company-operated wells. Gas is processed at a third party plant and then transmitted to an interstate pipeline.

Hugoton Area

The Hugoton Field covers parts of Texas, Oklahoma and Kansas and is one of the largest domestic gas fields with an estimated five million productive acres. We own an interest in 373 gross (350.5 net) operated wells and 78 gross (18.9 net) wells operated by others. During 2004, we continued our restimulation program in the Chase intervals with 33 restimulations. We plan to drill as many as seven wells and perform 50 Chase restimulations during 2005.

Approximately 75% of our Hugoton gas production is delivered to the Tyrone Plant, an operated gas processing plant. Improvements in the Hugoton area have included the acquisition of low pressure gathering lines and installation of lateral compressors that lowered the line pressure and increased production.

Green River Basin

The Green River Basin is located in southwestern Wyoming. We have interests in 195 gross (193.5 net) operated wells and 34 gross (4.3 net) wells operated by others in the Fontenelle Field area. Gas production is from the Frontier, Baxter and Dakota sandstones at depths ranging from 7,500 to 10,000 feet. Development potential for this area includes deepening and opening new producing zones in existing wells, drilling new wells and adding compression to lower line pressures. During 2004, we drilled seven gross (7.0 net) wells and performed 13 workovers. During 2005, we plan to perform seven workovers and drill up to ten wells in the Green River Basin.

Alaska Cook Inlet

We own a 100% working interest in two State of Alaska leases and offshore installations in the Middle Ground Shoal Field of the Cook Inlet. The properties include 27 wells, two platforms set in 70 feet of water about seven miles offshore, and a 50% interest in operated production pipelines and onshore processing facilities. The field has produced more than 130 million Bbls and is separated into East and West flanks by a crestal fault. Waterflooding of the East Flank has been successful, but the West Flank has not been fully developed or efficiently waterflooded. Production is from multiple zones within the Tyonek formation. We drilled two sidetrack wells in 2004 and plan to drill one East Flank well and one West Flank well in 2005.

RESERVES

The following terms are used in our disclosures of oil and natural gas reserves. For the complete detailed definitions of proved, proved developed and proved undeveloped oil and gas reserves applicable to oil and gas registrants, reference is made to Rule 4-10(a)(2)(3)(4) of Regulation S-X of the Securities and Exchange Commission, available at its web site http://www.sec.gov/divisions/corpfin/forms/regsx.htm#gas.

Proved reserves - Estimated quantities of crude oil, natural gas and natural gas liquids which, upon analysis of geologic and engineering data, appear with reasonable certainty to be recoverable in the future from known oil and gas reservoirs under existing economic and operating conditions.

Proved developed reserves - Proved reserves which can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved undeveloped reserves - Proved reserves which are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required.

Estimated future net revenues - Also referred to herein as "estimated future net cash flows." Computational result of applying current prices of oil and gas (with consideration of price changes only to the extent provided by existing contractual arrangements, other than hedge derivatives) to estimated future production from proved oil and gas reserves as of the date of the latest balance sheet presented, less estimated future expenditures (based on current costs) to be incurred in developing and producing the proved reserves.

Present value of estimated future net cash flows - The computational result of discounting estimated future net revenues at a rate of 10% annually. The present value of estimated future net cash flows after income tax is also referred to herein as "standardized measure of discounted future net cash flows" or "standardized measure."

The following are estimated quantities of proved reserves and related cash flows as of December 31, 2004, 2003 and 2002:

	DECEMBER 31		
(IN THOUSANDS)	2004	2003	2002
Proved developed:			
Gas (Mcf)	3,252,711	2,651,259	2,042,661
Natural gas liquids (Bbls)	30,019	28,187	19,367
Oil (Bbls)	134,382	47,882	47,178
Mcfe	4,239,117	3,107,673	2,441,931
Proved undeveloped:			
Gas (Mcf)	1,461,792	992,980	838,520
Natural gas liquids (Bbls)	8,437	6,491	6,066
Oil (Bbls)	18,124	7,549	9,171
Mcfe	1,621,158	1,077,220	929,942
Total proved:			
Gas (Mcf)	4,714,503	3,644,239	2,881,181
Natural gas liquids (Bbls)	38,456	34,678	25,433
Oil (Bbls)	152,506	55,431	56,349
Mcfe	5,860,275	4,184,893	3,371,873
Estimated future net cash flows:			
Before income tax	$ 23,605,059	$ 16,700,605	$ 10,165,876
After income tax	$ 16,238,874	$ 11,558,304	$ 7,148,542
Present value of estimated future net cash flows, discounted at 10%:			
Before income tax	$ 12,237,044	$ 8,607,001	$ 5,281,077
After income tax	$ 8,402,443	$ 5,989,685	$ 3,756,442

Miller and Lents, Ltd., an independent petroleum engineering firm, prepared the estimates of our proved reserves and the future net cash flows (and related present value) attributable to proved reserves at December 31, 2004, 2003 and 2002. As prescribed by the Securities and Exchange Commission, such proved reserves were estimated using oil and gas prices and production and development costs as of December 31 of each such year, without escalation. None of our natural gas liquid proved reserves are attributable to gas plant ownership. Year-end 2004 average realized prices used in the estimation of proved reserves were $5.69 per Mcf for gas, $28.24 per Bbl for natural gas liquids and $41.03 per Bbl for oil. See Note 15 to Consolidated Financial Statements for additional information regarding estimated proved reserves.

In our prior reports, the estimated future net cash flows from proved reserves and related present value amounts were reported before reduction for estimated operated overhead expense. Operated overhead is a component of production expense in the consolidated income statements and is an allocation from general and administrative expense of the costs estimated to support the production function. As part of its periodic review of our filings, the staff of the Securities and Exchange Commission concluded that production expense components for proved reserve disclosures should be consistent with components of production expense recorded in the financial statements. Accordingly, we have restated estimated future net cash flows and the related present value amounts for all years presented, resulting in a reduction to these amounts of approximately 2% at December 31, 2003 and 3% at December 31, 2002.

Estimated future net cash flows, and the related 10% discounted present value, of year-end 2004 proved reserves are significantly higher than at year-end 2003 because of increased reserves related to acquisitions and development and higher oil and natural gas liquids prices used in the estimation of year-end proved reserves. Year-end 2003 product prices were $5.71 per Mcf for gas, $23.17 per Bbl for natural gas liquids and $30.55 per Bbl for oil.

Uncertainties are inherent in estimating quantities of proved reserves, including many factors beyond our control. Reserve engineering is a subjective process of estimating subsurface accumulations of oil and gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and the interpretation thereof. As a result, estimates by different engineers often vary, sometimes significantly. In addition, physical factors such as the results of drilling, testing and production subsequent to the date of an estimate, as well as economic factors such as change in product prices, may justify revision of such estimates. Accordingly, oil and gas quantities ultimately recovered will vary from reserve estimates.

During 2004, we filed estimates of oil and gas reserves as of December 31, 2003 with the U.S. Department of Energy on Form EIA-23 and Form EIA-28. These estimates are consistent with the reserve data reported for the year ended December 31, 2003 in Note 15 to Consolidated Financial Statements, with the exception that Form EIA-23 includes only reserves from properties that we operate.

Exploration and Production Data

For the following data, "gross" refers to the total wells or acres in which we own a working interest and "net" refers to gross wells or acres multiplied by the percentage working interest owned by us. Although many wells produce both oil and gas, a well is categorized as an oil well or a gas well based upon the ratio of oil to gas production.

Producing Wells

The following table summarizes producing wells as of December 31, 2004, all of which are located in the United States:

	Operated Wells		Nonoperated Wells		Total(a)	
	Gross	Net	Gross	Net	Gross	Net
Gas	6,683.5	5,667.9	4,308.5	669.8	10,992.0	6,337.7
Oil	2,027.5	1,643.5	5,084.5	474.6	7,112.0	2,118.1
Total	8,711.0	7,311.4	9,393.0	1,144.4	18,104.0	8,455.8

(a) 672.0 gross (378.5 net) gas wells and 9.0 gross (5.5 net) oil wells are dual completions.

Drilling Activity

The following table summarizes the number of wells drilled during the years indicated. As of December 31, 2004, we were in the process of drilling 284 gross (121.2 net) wells.

	Year Ended December 31					
	2004		2003		2002	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Completed as –						
Gas wells	584	372.0	390	289.5	303	227.2
Oil wells	33	23.9	42	30.0	27	15.5
Non-productive	27	12.4	7	3.0	13	5.9
Total	644	408.3	439	322.5	343	248.6
Exploratory wells:						
Completed as –						
Gas wells	1	1.0	12	10.2	—	—
Oil wells	2	0.4	—	—	—	—
Non-productive	—	—	—	—	3	1.5
Total	3	1.4	12	10.2	3	1.5
Total(a)	647	409.7	451	332.7	346	250.1

(a) Included in totals are 212 gross (27.3 net) wells in 2004, 102 gross (17.66 net) wells in 2003 and 75 gross (11.2 net) wells in 2002, drilled on nonoperated interests.

Acreage

The following table summarizes developed and undeveloped leasehold acreage in which we own a working interest as of December 31, 2004. Acreage related to royalty, overriding royalty and other similar interests is excluded from this summary.

	Developed Acres (a)(b)		Undeveloped Acres	
	Gross	Net	Gross	Net
Texas	811,785	575,617	152,209	117,173
Oklahoma	546,238	381,312	16,946	8,158
Arkansas	577,937	306,590	30,507	22,299
New Mexico	450,044	284,802	33,395	27,825
Kansas	211,253	167,245	–	–
Louisiana	114,659	61,215	160	160
Colorado	107,900	83,875	–	–
Wyoming	72,442	55,506	53,963	51,246
Utah	66,939	42,546	–	–
Other	362,354	9,608	–	–
Total	3,321,551	1,968,316	287,180	226,861

(a) Developed acres are acres spaced or assignable to productive wells.

(b) Certain acreage in Oklahoma and Texas is subject to a 75% net profits interest conveyed to the Cross Timbers Royalty Trust, and in Oklahoma, Kansas and Wyoming is subject to an 80% net profits interest conveyed to the Hugoton Royalty Trust.

Oil and Gas Sales Prices and Production Costs

The following table shows the average sales prices per unit of production and the production expense and taxes, transportation and other expense per Mcfe for quantities produced for the indicated period:

	Year Ended December 31		
	2004	2003	2002
Sales prices:			
Gas (per Mcf)	$ 5.04	$ 4.07	$ 3.49
Natural gas liquids (per Bbl)	$ 26.44	$ 19.99	$ 14.31
Oil (per Bbl)	$ 38.38	$ 28.59	$ 24.24
Production expense per Mcfe	$ 0.66	$ 0.58	$ 0.57
Production and property taxes per Mcfe	$ 0.30	$ 0.21	$ 0.15
Transportation and other expense per Mcfe	$ 0.17	$ 0.16	$ 0.10

Delivery Commitments

Under a production payment sold in 1998, we have committed to deliver 16.0 Bcf (13.0 Bcf net to our interest) beginning approximately September 2006. Delivery of the committed volumes is in East Texas. See Note 8 to Consolidated Financial Statements. The Company's production and reserves are adequate to meet this delivery commitment.

Competition and Markets

We compete with other oil and gas companies in all aspects of our business, including acquisition of producing properties and oil and gas leases, marketing of oil and gas, and obtaining goods, services and labor. Some of our competitors have substantially larger financial and other resources. Factors that affect our ability to acquire producing properties include available funds, available information about the property and our standards established for minimum projected return on investment. Gathering systems are the only practical method for the intermediate transportation of natural gas. Therefore, competition for natural gas delivery is presented by other pipelines and gathering systems. Competition is also presented by alternative fuel sources, including heating oil, imported liquified natural gas and other fossil fuels. Because of the long-lived, high margin nature of our oil and gas reserves and management's experience and expertise in exploiting these reserves, management believes that it effectively competes in the market.

Our ability to market oil and gas depends on many factors beyond our control, including the extent of domestic production and imports of oil and gas, the proximity of our gas production to pipelines, the available capacity in such pipelines, the demand for oil and gas, and the effects of weather and state and federal regulation. We cannot assure that we will always be able to market all of our production at favorable prices. We do not currently believe that the loss of any of our oil or gas purchasers would have a material adverse effect on our operations.

Decreases in oil and gas prices have had and could have in the future an adverse effect on our acquisition and development programs, proved reserves, revenues, profitability, cash flow and dividends. See Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, "Significant Events, Transactions and Conditions - Product Prices."

Federal and State Regulations

There are numerous federal and state laws and regulations governing the oil and gas industry that are often changed in response to the current political or economic environment. Compliance with this regulatory burden is often difficult and costly and may carry substantial penalties for noncompliance. The following are some specific regulations that may affect us. We cannot predict the impact of these or future legislative or regulatory initiatives.

Federal Energy Bill

After failing to pass legislation in 2003 and 2004, Congress is currently considering a new energy bill. The potential effect of this legislation is unknown, but it may include certain tax incentives for oil and gas producers and changes in the federal regulatory framework.

Federal Regulation of Natural Gas

The interstate transportation and certain sales for resale of natural gas, including transportation rates charged and various other matters, is subject to federal regulation by the Federal Energy Regulatory Commission. Federal wellhead price controls on all domestic gas were terminated on January 1, 1993, and none of our gathering systems are currently subject to FERC regulation. We cannot predict the impact of future government regulation on any natural gas facilities.

Although FERC's regulations should generally facilitate the transportation of gas produced from our properties and the direct access to end-user markets, the future impact of these regulations on marketing our production or on our gas transportation business cannot be predicted. We, however, do not believe that we will be affected differently than competing producers and marketers.

Federal Regulation of Oil

Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at market prices. The net price received from the sale of these products is affected by market transportation costs. A significant part of our oil production is transported by pipeline. Under rules adopted by FERC effective January 1995, interstate oil pipelines can change rates based on an inflation index, though other rate mechanisms may be used in specific circumstances. These rules have had little effect on our oil transportation cost.

State Regulation

Oil and gas operations are subject to various types of regulation at the state and local levels. Such regulation includes requirements for drilling permits, the method of developing new fields, the spacing and operations of wells and waste prevention. The production rate may be regulated and the maximum daily production allowable from oil and gas wells may be established on a market demand or conservation basis. These regulations may limit production by well and the number of wells that can be drilled.

We may become a party to agreements relating to the construction or operations of pipeline systems for the transportation of natural gas. To the extent that such gas is produced, transported and consumed wholly within one state, such operations may, in certain instances, be subject to the state's administrative authority charged with regulating pipelines. The rates that can be charged for gas, the transportation of gas, and the construction and operation of such pipelines would be subject to the regulations governing such matters. Certain states have recently adopted regulations with respect to gathering systems, and other states are considering similar regulations. New regulations have not had a material effect on the operations of our gathering systems, but we cannot predict whether any further rules will be adopted or, if adopted, the effect these rules may have on our gathering systems.

Our operations on federal, state or Native American oil and gas leases are subject to numerous restrictions, including nondiscrimination statutes. Such operations must be conducted pursuant to certain on-site security regulations and other permits and authorizations issued by the Bureau of Land Management, Minerals Management Service and other agencies.

Environmental Regulations

Various federal, state and local laws regulating the discharge of materials into the environment, or otherwise relating to the protection of the environment, directly impact oil and gas exploration, development and production operations, and consequently may impact our operations and costs. These laws and regulations govern, among other things, emissions to the atmosphere, discharges of pollutants into waters of the United States, underground injection of waste water, the generation, storage, transportation and disposal of waste materials, and protection of public health, natural resources and wildlife. These laws and regulations may impose substantial liabilities for noncompliance and for any contamination resulting from our operations and may require the suspension or cessation of operations in affected areas. To date, we have not expended any material amounts to comply with such regulations, and management does not currently anticipate that future compliance will have a materially adverse effect on our consolidated financial position or results of operations.

We are committed to environmental protection and believe we are in substantial compliance with applicable environmental laws and regulations. We routinely obtain permits for our facilities and operations in accordance with the applicable laws and regulations. There are no known issues that have a significant adverse effect on the permitting process or permit compliance status of any of our facilities or operations. We have made, and will continue to make, expenditures in our efforts to comply with environmental regulations and requirements. These costs are considered a normal, recurring cost of our ongoing operations and not an extraordinary cost of compliance with government regulations.

Employees

We had 1,356 employees as of December 31, 2004. We consider our relations with our employees to be good.

Executive Officers of the Company

The executive officers of the Company are elected by and serve until their successors are elected by the Board of Directors.

Bob R. Simpson, 56, was a co-founder of the Company with Mr. Palko and has been Chairman and Chief Executive Officer since July 1, 1996. Prior thereto, Mr. Simpson served as Vice Chairman and Chief Executive Officer or held similar positions with the Company since 1986. Mr. Simpson was Vice President of Finance and Corporate Development (1979-1986) and Tax Manager (1976-1979) of Southland Royalty Company.

Steffen E. Palko, 54, was a co-founder of the Company with Mr. Simpson and has been Vice Chairman and President or held similar positions since 1986. Mr. Palko was Vice President - Reservoir Engineering (1984-1986) and Manager of Reservoir Engineering (1982-1984) of Southland Royalty Company.

Louis G. Baldwin, 55, has been Executive Vice President and Chief Financial Officer or held similar positions with the Company since 1986. Mr. Baldwin was Assistant Treasurer (1979-1986) and Financial Analyst (1976-1979) at Southland Royalty Company.

Keith A. Hutton, 46, has been Executive Vice President - Operations or held similar positions with the Company since 1987. From 1982 to 1987, Mr. Hutton was a Reservoir Engineer with Sun Exploration & Production Company.

Vaughn O. Vennerberg II, 50, has been Executive Vice President - Administration or held similar positions with the Company since 1987. Prior to that time, Mr. Vennerberg was employed by Cotton Petroleum Corporation and Texaco Inc. (1979-1986).

Bennie G. Kniffen, 54, has been Senior Vice President and Controller or held similar positions with the Company since 1986. From 1976 to 1986, Mr. Kniffen held the position of Director of Auditing or similar positions with Southland Royalty Company.

Item 3

LEGAL PROCEEDINGS

On October 17, 1997, an action, styled *United States of America ex rel. Grynberg v. Cross Timbers Oil Company, et al.*, was filed in the U.S. District Court for the Western District of Oklahoma by Jack J. Grynberg on behalf of the United States under the *qui tam* provisions of the U.S. False Claims Act against the Company and certain of our subsidiaries. The plaintiff alleges that we underpaid royalties on natural gas produced from federal leases and lands owned by Native Americans in amounts in excess of 20% as a result of mismeasuring the volume of natural gas, incorrectly analyzing its heating content and improperly valuing the natural gas during at least the past ten years. The plaintiff seeks treble damages for the unpaid royalties (with interest, attorney fees and expenses), civil penalties between $5,000 and $10,000 for each violation of the U.S. False Claims Act, and an order for us to cease the allegedly improper measuring practices. This lawsuit against us and similar lawsuits filed by Grynberg against more than 300 other companies have been consolidated in the United States District Court for Wyoming. In October 2002, the court granted a motion to dismiss Grynberg's royalty valuation claims, and Grynberg's appeal of this decision was dismissed for lack of appellate jurisdiction in May 2003. The parties have completed discovery regarding whether the plaintiff has met the jurisdictional prerequisites for maintaining an action under the U.S. False Claims Act. In June 2004, we joined with other defendants in filing a motion to dismiss, contending that the plaintiff has not satisfied the jurisdictional requirements to maintain this action. A hearing on this motion has been scheduled for March 2005. While we are unable to predict the outcome of this case, we believe that the allegations of this lawsuit are without merit and intend to vigorously defend the action. Any potential liability from this claim cannot currently be reasonably estimated, and no provision has been accrued in our financial statements.

In June 2001, we were served with a lawsuit styled *Price, et al. v. Gas Pipelines, et al.* (formerly *Quinque* case). The action was filed in the District Court of Stevens County, Kansas, against us and one of our subsidiaries, along with over 200 natural gas transmission companies, producers, gatherers and processors of natural gas. The plaintiffs seek to represent a class of plaintiffs consisting of all similarly situated gas working interest owners, overriding royalty owners and royalty owners either from whom the defendants had purchased natural gas or who received economic benefit from the sale of such gas since January 1, 1974. The allegations in the case are similar to those in the *Grynberg* case; however, the *Price* case broadens the claims to cover all oil and gas leases (other than the federal and Native American leases that are the subject of the *Grynberg* case). The complaint alleges that the defendants have mismeasured both the volume and heating content of natural gas delivered into their pipelines, resulting in underpayments to the plaintiffs. The plaintiffs assert a breach of contract claim, negligent or intentional misrepresentation, civil conspiracy, common carrier liability, conversion, violation of a variety of Kansas statutes and other common law causes of action. The amount of damages was not specified in the complaint. In February 2002, we, along with one of our subsidiaries, were dismissed from the suit and another subsidiary of the Company was added. A hearing was held in January 2003, and the court held that a class should not be certified. The plaintiffs' counsel has filed an amended class action petition, which reduces the proposed class to only royalty owners, reduces the claims to mismeasurement of volume only, conspiracy, unjust enrichment and accounting, and only applies to gas measured in Kansas, Colorado and Wyoming. The court has set an evidentiary hearing in April 2005 to determine whether the amended class should be certified. While we are unable to predict the outcome of this case, we believe that the allegations of this lawsuit are without merit and intend to vigorously defend the action. Any potential liability from this claim cannot currently be reasonably estimated, and no provision has been accrued in our financial statements.

On August 5, 2003, the *Price* plaintiffs served one of our subsidiaries with a new original class action petition styled *Price, et al. v. Gas Pipelines, et al.* The action was filed in the District Court of Stevens County, Kansas, against natural gas pipeline owners and operators. The plaintiffs seek to represent a class of plaintiffs consisting of all similarly situated gas royalty owners either from whom the defendants had purchased natural gas or measured natural gas since January 1, 1974 to the present. The new petition alleges the same improper analysis of gas heating content that had previously been alleged in the *Price* case discussed above until it was removed from the case by the filing of the amended class action petition. In all other respects, the new petition appears to be identical to the amended class action petition in that it has a proposed class of only royalty owners, alleges conspiracy, unjust enrichment and accounting, and only applies to gas measured in Kansas, Colorado and Wyoming. The court has set an evidentiary hearing in April 2005 to determine whether the amended class should be certified. The amount of damages was not specified in the complaint. While we are unable to predict the outcome of this case, we believe that the allegations of this lawsuit are without merit and intend to vigorously defend the action. Any potential liability from this claim cannot currently be reasonably estimated, and no provision has been accrued in our financial statements.

In September 2004, we were served with a lawsuit styled *Burkett, et al. v. J.M. Huber Corp. and XTO Energy Inc.* The action was filed in the District Court of La Plata County, Colorado against us and J.M. Huber Corporation. The plaintiffs allege that the defendants have deducted in their calculation of royalty payments expenses of compression, gathering, treatment, dehydration, or other costs to place the natural gas produced in a marketable condition at a marketable location. The plaintiffs seek to represent a class consisting of all lessors and their successors in interest who own or have owned mineral interests located in La Plata County, Colorado and that are leased to or operated by Huber or us, except to the extent that the lessors or their successors have expressly authorized deduction of post-production expenses from royalties. We acquired the interests of Huber in producing properties in La Plata County effective October 1, 2002, and have assumed the responsibility for certain liabilities of Huber prior to the effective date, which may include liability for post-production deductions made by Huber. As of December 31, 2004, based on an evaluation of available information, we accrued a $3.1 million estimated liability for this claim in our consolidated financial statements. On February 17, 2005, we agreed to a tentative settlement of approximately $5.1 million, resulting in an additional loss of approximately $2 million to be recorded in first quarter 2005.

In December 2004, the U.S. Environmental Protection Agency issued a Compliance Agreement and Final Order to us, which cited certain violations concerning the discharge of produced water and sanitary wastes into Alaska's Cook Inlet from our two operated production platforms from January 2000 through June 2004. We reported these discharges to the EPA as part of our offshore discharge permit monitoring. We have agreed to pay a monetary penalty of $139,000 and have accrued this amount in our financial statements.

We are involved in various other lawsuits and certain governmental proceedings arising in the ordinary course of business. Our management and legal counsel do not believe that the ultimate resolution of these claims, including the lawsuits described above, will have a material effect on our financial position or liquidity, although an unfavorable outcome could have a material adverse effect on the operations of a given interim period or year.

PART I

Item 4

Submission *of* Matters to a Vote *of* Security Holders

A Special Meeting of the Shareholders of the Company was held on November 16, 2004, to vote on the proposed 2004 Stock Incentive Plan. All common shares in this Item 4 have been retroactively restated for the effect of the four-for-three stock split to be effected on March 15, 2005. A total of 268,690,021 of the Company's shares were present at the meeting in person or by proxy, which represented 77% of our outstanding shares as of September 30, 2004, the record date for the Special Meeting.

Shareholders approved the 2004 Stock Incentive Plan, based on the following vote tabulation:

For	Against	Withheld
212,600,831	55,755,692	333,498

Item 5

MARKET *for* REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS *and* ISSUER PURCHASES *of* EQUITY SECURITIES

Our common stock is listed on the New York Stock Exchange and trades under the symbol "XTO." The following table sets forth quarterly high and low sales prices and cash dividends declared for each quarter of 2004 and 2003 (as adjusted for the four-for-three stock split to be effected on March 15, 2005, the five-for-four stock split effected in March 2004, and the four-for-three stock split effected in March 2003):

	HIGH	LOW	CASH DIVIDEND
2004			
First Quarter	$ 19.512	$ 15.348	$ 0.0075
Second Quarter	22.875	18.315	0.0075
Third Quarter	24.833	19.050	0.0375
Fourth Quarter	27.660	22.350	0.0375
2003			
First Quarter	$ 11.916	$ 10.211	$ 0.0060
Second Quarter	13.494	10.920	0.0060
Third Quarter	12.852	11.148	0.0060 (a)
Fourth Quarter	17.580	12.558	0.0060

(a) In September 2003, we distributed as a dividend to our shareholders all of the Cross Timbers Royalty Trust units owned by the Company. This dividend was recorded at a market value of $28.2 million, or approximately $0.09 per common share.

The determination of the amount of future dividends, if any, to be declared and paid is at the sole discretion of the Board of Directors and will depend on our financial condition, earnings and cash flow from operations, the level of our capital expenditures, our future business prospects and other matters the Board of Directors deems relevant.

On February 15, 2005, the Board of Directors declared a quarterly dividend of $0.05 per common share payable on April 15, 2005 to stockholders of record on March 31, 2004. As a result of the four-for-three stock split to be effected on March 15, 2005, this represents a 33% increase in our dividend rate. On February 23, 2005, we had 1,054 stockholders of record.

The following summarizes purchases of our common stock during fourth quarter 2004:

MONTH	TOTAL NUMBER OF SHARES PURCHASED	AVERAGE PRICE PAID PER SHARE	TOTAL NUMBER OF SHARES PURCHASED AS PART OF PUBLICLY ANNOUNCED PLANS OR PROGRAMS (b)	MAXIMUM NUMBER OF SHARES THAT MAY YET BE PURCHASED UNDER THE PLANS OR PROGRAMS (b)
October	–	$ –	–	
November	696 (a)	$ 27.26	–	
December	33,600	$ 24.18	33,600	
Total	34,296	$ 24.24	33,600	19,966,400

(a) During the quarter ended December 31, 2004, the Company purchased shares of common stock as treasury shares to pay income tax withholding obligations in conjunction with vesting of performance shares under the 1998 Stock Incentive Plan. These share purchases were not part of a publicly announced program to purchase common shares.

(b) The Company has a repurchase program approved by the Board of Directors for the repurchase of up to 20,000,000 shares of the Company's common stock. The repurchase program was announced on August 18, 2004.

Item 6

SELECTED FINANCIAL DATA

The following table shows selected financial information for each of the years in the five-year period ended December 31, 2004. Significant producing property acquisitions in each of the years presented, other than 2000, affect the comparability of year-to-year financial and operating data. See Items 1 and 2, Business and Properties, "Acquisitions." All weighted average shares and per share data have been adjusted for the four-for-three stock split to be effected on March 15, 2005, the five-for-four stock split effected in March 2004, the four-for-three stock split effected in March 2003 and the three-for-two stock splits effected in June 2001 and September 2000. This information should be read in conjunction with Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations and the Consolidated Financial Statements at Item 15(a).

(IN THOUSANDS EXCEPT PRODUCTION, PER SHARE AND PER UNIT DATA)	2004	2003	2002	2001	2000
Consolidated Income Statement Data					
Revenues:					
Gas and natural gas liquids	$ 1,613,135	$ 1,040,370	$ 681,147	$ 710,348	$ 456,814
Oil and condensate	318,800	135,058	115,324	116,939	128,194
Gas gathering, processing and marketing	18,380	12,982	11,622	12,832	16,123
Other	(2,714)	1,145	2,070	(1,371)	(280)
Total Revenues	$ 1,947,601	$ 1,189,555	$ 810,163	$ 838,748	$ 600,851
Earnings available to common stock	$ 507,882 (a)	$ 288,279 (b)	$ 186,059 (c)	$ 248,816 (d)	$ 115,235 (e)
Per common share:					
Basic	$ 1.53	$ 0.96 (f)	$ 0.67	$ 0.91 (g)	$ 0.49
Diluted	$ 1.51	$ 0.95 (f)	$ 0.66	$ 0.90 (g)	$ 0.46
Weighted average common shares outstanding	332,907	299,665	277,834	272,234	237,179
Cash dividends declared per common share	$ 0.0900	$ 0.0240 (h)	$ 0.0180	$ 0.0165	$ 0.0100
Consolidated Statement of Cash Flows Data					
Cash provided (used) by:					
Operating activities	$ 1,216,892	$ 794,181	$ 490,842	$ 542,615	$ 377,421
Investing activities	$ (2,518,261)	$ (1,135,234)	$ (736,817)	$ (610,923)	$ (133,884)
Financing activities	$ 1,304,074	$ 333,094	$ 254,119	$ 67,680	$ (241,833)
Consolidated Balance Sheet Data					
Property and equipment, net	$ 5,624,378	$ 3,312,067	$ 2,370,965	$ 1,841,387	$ 1,357,374
Total assets	$ 6,110,372	$ 3,611,134	$ 2,648,193	$ 2,132,327	$ 1,591,904
Long-term debt	$ 2,042,732	$ 1,252,000	$ 1,118,170	$ 856,000	$ 769,000
Stockholders' equity	$ 2,599,373	$ 1,465,642	$ 907,786	$ 821,050	$ 497,367
Operating Data					
Average daily production:					
Gas (Mcf)	834,572	668,436	513,925	416,927	343,871
Natural gas liquids (Bbls)	7,484	6,463	5,068	4,385	4,430
Oil (Bbls)	22,696	12,943	13,033	13,637	12,941
Mcfe	1,015,654	784,877	622,532	525,062	448,098
Average sales price:					
Gas (per Mcf)	$ 5.04	$ 4.07	$ 3.49	$ 4.51	$ 3.38
Natural gas liquids (per Bbl)	$ 26.44	$ 19.99	$ 14.31	$ 15.41	$ 19.61
Oil (per Bbl)	$ 38.38	$ 28.59	$ 24.24	$ 23.49	$ 27.07
Production expense (per Mcfe)	$ 0.66	$ 0.58	$ 0.57	$ 0.57	$ 0.53
Taxes, transportation and other expense (per Mcfe)	$ 0.47	$ 0.37	$ 0.25	$ 0.33	$ 0.35
Proved reserves:					
Gas (Mcf)	4,714,503	3,644,239	2,881,181	2,235,478	1,769,683
Natural gas liquids (Bbls)	38,456	34,678	25,433	20,299	22,012
Oil (Bbls)	152,506	55,431	56,349	54,049	58,445
Mcfe	5,860,275	4,184,893	3,371,873	2,681,566	2,252,425
Other Data					
Ratio of earnings to fixed charges (i)	8.9	6.9	5.6	7.7	2.8

(a) Includes pre-tax effects of a derivative fair value loss of $11.9 million, stock-based incentive compensation of $89.5 million and special bonuses totaling $11.7 million related to the ChevronTexaco and ExxonMobil acquisitions. Stock-based incentive compensation includes cash compensation of $22.3 million related to cash-equivalent performance shares.

(b) Includes pre-tax effects of a derivative fair value loss of $10.2 million, a non-cash contingency gain of $1.7 million, non-cash incentive compensation of $53.1 million, a $9.6 million loss on extinguishment of debt, a $16.2 million non-cash gain on the distribution of Cross Timbers Royalty Trust units, and a $1.8 million after-tax gain on adoption of the new accounting standard for asset retirement obligation.

(c) Includes pre-tax effects of a derivative fair value gain of $2.6 million, gain on settlement with Enron Corporation of $2.1 million, non-cash incentive compensation of $27 million and an $8.5 million loss on extinguishment of debt.

(d) Includes pre-tax effects of a derivative fair value gain of $54.4 million and non-cash incentive compensation of $9.6 million, and an after-tax charge of $44.6 million for the cumulative effect of accounting change.

(e) Includes pre-tax effects of a derivative fair value loss of $55.8 million, a gain of $43.2 million on significant asset sales, and non-cash incentive compensation expense of $26.1 million.

(f) Before cumulative effect of accounting change, earnings per share were $0.95 basic and $0.94 diluted.

(g) Before cumulative effect of accounting change, earnings per share were $1.08 basic and $1.06 diluted.

(h) Excludes the September 2003 distribution of all of the Cross Timbers Royalty Trust units owned by the Company to its stockholders as a dividend with a market value of approximately $0.09 per common share.

(i) For purposes of calculating this ratio, earnings are before income tax and fixed charges. Fixed charges include interest costs and the portion of rentals considered to be representative of the interest factor.

PART II

Item 7

MANAGEMENT'S DISCUSSION *and* ANALYSIS *of* FINANCIAL CONDITION *and* RESULTS *of* OPERATIONS

The following discussion and analysis should be read in conjunction with Item 6, Selected Financial Data, and the Consolidated Financial Statements at Item 15(a). Unless otherwise indicated, throughout this discussion the term "Mcfe" refers to thousands of cubic feet of gas equivalent quantities produced for the indicated period, with oil and natural gas liquid quantities converted to Mcf on an energy equivalent ratio of one barrel to six Mcf.

OVERVIEW

Our business is to produce and sell natural gas, natural gas liquids and crude oil from our predominantly southwestern and central U.S. properties, most of which we operate. Because we consider our gathering, processing and marketing as ancillary functions to our production of natural gas, natural gas liquids and crude oil, we have determined that our business comprises only one industry segment.

In 2004, we achieved the following record financial and operating results:

- Average daily gas production was 835,000 Mcf, a 25% increase from 2003, average daily oil production was 22,696 Bbls, a 75% increase from 2003, and average daily natural gas liquids production was 7,484 Bbls, a 16% increase from 2003.
- Year-end proved reserves were 5.86 Tcfe, a 40% increase from year-end 2003.
- Net income was $507.9 million, a 76% increase from 2003, and earnings per basic common share was $1.53, a 59% increase from 2003.
- Cash flow from operating activities was $1.22 billion, a 53% increase from 2003.
- Stockholders' equity was $2.6 billion, a 77% increase from year-end 2003.
- The debt-to-capitalization ratio improved to 44% at year-end from 46% at year-end 2003.

We achieve production and proved reserve growth primarily through producing property acquisitions, followed by low-risk development generally funded by cash flow from operating activities. Funding sources for our acquisitions include proceeds from sales of public and private equity and debt, bank borrowings, cash flow from operating activities, or a combination of these sources. Maintaining or improving our debt-to-capitalization ratio is a primary consideration in selecting our method of acquisition financing.

During 2004, we acquired $1.9 billion of producing properties with proved reserves of 716.5 Bcf of natural gas, 2.9 million Bbls of natural gas liquids and 98.2 million Bbls of oil. In January 2005, we announced an agreement to acquire Antero Resources Corporation, a prominent producer in the Barnett Shale of North Texas, for cash and equity consideration of approximately $685 million. The agreement was amended in February to include Antero's gas gathering assets and related bank debt of $175 million.

Our goal for 2005 is to increase production by 21% to 23%. To achieve future production and reserve growth, we will continue to pursue acquisitions that meet our criteria, and to complete development projects included in our inventory of between 3,100 and 3,850 potential development drilling locations. Our 2005 development budget is $850 million. While an acquisition budget has not been formalized, we plan to actively review additional acquisition opportunities during 2005. We cannot ensure that we will be able to find properties that meet our acquisition criteria and that we can purchase such properties on acceptable terms.

The weak U.S. dollar, raw material shortages and strong global demand for steel have continued to tighten steel supplies and cause prices to remain high. In response, we have increased our tubular inventory and have negotiated supply contracts with our vendors to support our development program. While we expect to acquire adequate supplies to complete our development program, a further tightening of steel supplies could restrain the program, limiting production growth and increasing development costs.

Sales prices for our natural gas and oil production are influenced by supply and demand conditions over which we have little or no control, including weather and regional and global economic conditions. To provide predictable production growth, we hedge a portion of our production at prices that ensure stable cash flow margins to fund our operating commitments and development program. As of February 25, 2005, we have hedged approximately 25% of our 2005 projected gas production at an average NYMEX price of $5.90 per Mcf and about 45% of our crude oil production at an average NYMEX price of $38.37 per Bbl. Our average realized price on hedged production will be lower than these average NYMEX prices because of location, quality and other adjustments.

The combined effect of higher product prices, a 25% increase in gas production and a 75% increase in oil production resulted in a 64% increase in total revenues to $1.95 billion in 2004 from $1.19 billion in 2003. On an Mcfe produced basis, total revenues were $5.24 in 2004, a 26% increase from $4.15 in 2003.

We analyze, on an Mcfe produced basis, expenses that generally trend changes in production:

	2004	2003	Increase (Decrease)
Production	$ 0.66	$ 0.58	14%
Taxes, transportation and other	0.47	0.37	27%
Depreciation, depletion and amortization	1.09	0.99	10%
Accretion of discount in asset retirement obligation	0.02	0.02	–
General and administrative, excluding stock-based incentive compensation	0.20	0.19	5%
Interest	0.25	0.22	14%
	$ 2.69	$ 2.37	14%

Production expense rose 14% primarily because of the 75% increase in oil production, which is more expensive to produce than natural gas. Taxes, transportation and other expense generally is based on product revenues, and the 27% increase in this expense per Mcfe is primarily caused by increased product prices. The 10% increase in depreciation, depletion and amortization resulted from higher acquisition and development costs. The 5% increase in general and administrative expense is because of increased personnel and other costs related to Company growth.

Significant expenses that generally do not trend with production include:

Stock-based incentive compensation. This is a component of general and administrative expense and primarily relates to the vesting of performance shares when the common stock price reaches specified target levels. Incentive compensation was $89.5 million in 2004, a 69% increase from the comparable 2003 expense of $53.1 million. Included in 2004 incentive compensation is $22.3 million of cash compensation related to vesting of cash-equivalent performance shares. Otherwise, stock-based incentive compensation was non-cash. Increased incentive compensation is because of the 56% increase in the common stock price during 2004 and the resulting increased value of vested awards. After adjusting for the effect of the May 2004 and April 2003 common stock offerings, stock-based incentive compensation was approximately 3% of the increase in market capitalization during each of 2004 and 2003. Including stock-based incentive compensation, general and administrative expense increased $57.4 million, or 53%.

Derivative fair value (gain) loss. This is the net realized and unrealized gain or loss on derivative financial instruments that do not qualify for hedge accounting treatment and fluctuates based on changes in the fair value of underlying commodities. Derivative fair value losses of $11.9 million in 2004 and $10.2 million in 2003 were primarily related to the ineffective portion of hedge derivatives caused by the effect of increasing oil and gas prices on hedges in areas without basis or location differential contracts.

Our primary sources of liquidity are cash flow from operating activities, borrowings under our revolving credit facility with commercial banks and public and private offerings of equity and debt. In January 2004, Standard & Poors upgraded our corporate credit rating to investment grade and all liens on producing properties and other collateral were irrevocably released as security for our revolving credit agreement with commercial banks. As a result, Moody's upgraded our existing senior notes to Ba1 from Ba2 and confirmed our Ba1 senior implied rating. In March 2004, Moody's upgraded our issuer rating and senior implied rating to Baa3.

In February 2004, we fully repaid our revolving credit agreement and entered a new five-year revolving credit agreement with commercial banks that matures in February 2009. The agreement currently provides for a maximum commitment amount of $1 billion, and an interest rate based on the London Interbank Offered Rate plus 1%. On December 31, 2004, borrowings under the revolving credit agreement with commercial banks were $146 million at a weighted average interest rate of 3.49%, with unused borrowing capacity of $854 million. In November 2004, we borrowed $300 million under a five-year bank term loan due April 2010 with an initial interest rate of LIBOR plus 0.75%. Other terms and conditions are substantially the same as our existing revolving credit agreement.

Our consolidated financial position and results of operations are significantly affected by our critical accounting policies and estimates. We utilize the successful efforts method of oil and gas accounting that requires expensing of unsuccessful exploratory well costs, as well as exploratory geological and geophysical costs. All acquisition, development and successful exploratory well costs are generally capitalized and expensed through depreciation, depletion and amortization, which is computed on the unit-of-production method. If conditions indicate our properties may be impaired, we estimate future net cash flows from the applicable properties and compare this estimate to our total net cost of the properties. If the property cost cannot be recovered from the estimated future net cash flows, we must write down the property cost to the discounted present value of such future net cash flows. To date, our impairment of producing properties has been limited to a $2 million provision recorded in 1998. While we do not expect significant impairment provisions in the near future, any prolonged significant decline in commodity prices could require an impairment adjustment to our property cost. The amounts we record for depreciation, depletion and amortization and impairment are dependent upon our estimates of proved oil and gas reserves. Our proved reserve estimates are subject to potentially significant revisions based on subsequent drilling results and production data, changes in prices and costs, as well as other factors.

Significant Events, Transactions and Conditions

The following events, transactions and conditions affect the comparability of results of operations and financial condition for each of the years ended December 31, 2004, 2003 and 2002 and may impact future operations and financial condition.

Acquisitions. We acquired producing and undeveloped properties at a total cost of $2.0 billion in 2004, $629.5 million in 2003 and $358.1 million in 2002, which were funded by a combination of proceeds from sales of common stock and senior notes, bank borrowings and cash flow from operating activities. The following are the significant acquisitions:

Closing Date		Seller	Amount (in millions)	Acquisition Area
2004	January	Multiple parties	$ 243	East Texas and northwestern Louisiana
	February-April	Multiple parties	223	Barnett Shale of North Texas and Arkoma Basin
	May	ExxonMobil Corporation	336	Permian Basin of West Texas and Powder River Basin of Wyoming
	August	ChevronTexaco Corporation	930	Eastern Region, Permian Basin, Mid-Continent, Rocky Mountains and South Texas
2003	May	Williams of Tulsa, Oklahoma	381	Raton Basin of Colorado, Hugoton field of southwestern Kansas and San Juan Basin of New Mexico and Colorado
	June	Markwest Hydrocarbon, Inc.	51	San Juan Basin of New Mexico and Colorado
	October	Multiple parties	100	East Texas, Arkansas and San Juan Basin of New Mexico
2002	May	Marathon Oil Company	101	East Texas and Louisiana
	July	Marathon Oil Company	43	San Juan Basin of New Mexico
	December	J.M. Huber Corporation	154	San Juan Basin of Colorado

In January 2005, we announced an agreement to purchase privately held Antero Resources Corporation, a prominent Barnett Shale producer, for cash and equity consideration valued at approximately $685 million. Consideration includes $337.5 million in cash, 13.3 million shares of our common stock and five-year warrants to purchase another 2 million shares of our common stock at $27.00 per share. The purchase agreement was amended in February 2005 to include Antero's gas gathering assets and related bank debt of $175 million. The transaction is expected to close April 1, 2005. The booked acquisition cost will include customary non-cash adjustments, including a step-up for deferred taxes. The cash consideration for the acquisition will be initially provided through cash flow from operations and existing bank credit facilities.

2004, 2003 and 2002 Development and Exploration Programs. Gas development focused on the East Texas area and the Arkoma and San Juan basins during 2004, 2003 and 2002. Oil development was concentrated in Alaska and in the Permian Basin during all three years. Development costs totaled $572.1 million in 2004, $445.9 million in 2003 and $352.1 million in 2002. Exploration activity in 2004 was primarily geological and geophysical analysis, including seismic studies, of undeveloped properties. Exploration activity in 2003 and 2002 consisted primarily of drilling successful wells in East Texas. Exploratory costs were $15 million in 2004, $16.1 million in 2003 and $4.2 million in 2002. Our development and exploration activities are generally funded by cash flow from operations.

2005 Acquisition, Development and Exploration Program. We have budgeted $850 million for our 2005 development and exploration program, which we expect to fund by cash flow from operations. While an acquisition budget has not been formalized, we plan to continue to actively review additional acquisition opportunities during 2005. If acquisition, development and exploration expenditures exceed cash flow from operations, we expect to obtain additional funding through our bank credit facilities, public or private issuance of debt or equity, or asset sales. The cost of 2005 property acquisitions may alter the amount currently budgeted for development and exploration. Our total budget for acquisitions, development and exploration will be adjusted throughout 2005 to focus on opportunities offering the highest rates of return.

As of December 31, 2004, we have an inventory of between 3,100 and 3,850 potential drilling locations. We plan to drill about 735 (560 net) development wells and perform approximately 540 (400 net) workovers and recompletions in 2005. Drilling plans are dependent upon product prices and the availability of drilling equipment.

Product Prices. In addition to supply and demand, oil and gas prices are affected by seasonal, political and other conditions we generally cannot control or predict.

Gas. Natural gas prices are dependent upon North American supply and demand, which is affected by weather and economic conditions. Natural gas competes with alternative energy sources as a fuel for heating and the generation of electricity. The winter of 2001-2002 was one of the warmest on record, resulting in higher than average gas storage levels and lower gas prices in 2002. Prices climbed in fourth quarter 2002 as a result of low levels of drilling activity, increased industrial demand, colder weather and international instability. Colder than normal weather, record low gas storage levels and continued increasing demand caused gas prices to remain relatively high during the first five months of 2003. With diminished demand related to higher prices, natural gas prices were lower during the summer months, then rose with cooler weather in the fall and early winter. Forecasts for continued production declines, increasing natural gas demand and larger than projected storage withdrawals supported higher prices in the first six months of 2004. Mild summer weather and increased gas storage inventories led to declining gas prices in August and early September. Natural gas prices rose again in mid-September because of reduced gas production as a result of hurricanes in the Gulf of Mexico. Gas prices remained relatively high for the remainder of 2004 because of sporadic colder weather and lower gas supplies. With moderate temperatures and favorable supply, prices were lower in January 2005, but rose in February as a result of colder weather in the U.S. Northeast and Europe. Prices will continue to be affected by weather, the recovery of the domestic economy, increases in the level of North American production and import levels of liquified natural gas. In any case, management expects natural gas prices to remain volatile. As described under "Hedging Activities" below, we use commodity price hedging instruments to reduce our exposure to gas price fluctuations. The following are comparative average gas prices for the last three years:

	Year Ended December 31		
(per Mcf)	2004	2003	2002
Average NYMEX price	$ 6.14	$ 5.39	$ 3.22
Average realized sales price	$ 5.04	$ 4.07	$ 3.49
Average realized sales price excluding hedging	$ 5.56	$ 4.86	$ 2.98

At February 25, 2005, the average NYMEX gas price for the following 12 months was $7.23 per MMBtu. As computed on an energy equivalent basis, our proved reserves were 80% natural gas at December 31, 2004. After considering hedges in place as of February 25, 2005, we estimate that a $0.10 per Mcf increase or decrease in the average gas sales price would result in approximately a $25 million change in 2005 annual operating cash flow before income taxes.

Oil. Crude oil prices are generally determined by global supply and demand. Oil prices declined in 2002 because of lagging demand caused by a global recession. Rising uncertainties in the Middle East led to higher prices late in 2002. During 2003, unusually low storage levels, the war in Iraq and production discipline by OPEC maintained oil prices at relatively high levels. Oil prices continued to increase in early 2004 because of increasing demand and low crude stocks. Despite increased production by OPEC members, oil prices exceeded $55 per Bbl in October because of continued instability in the Middle East and Nigeria and hurricanes in the Gulf of Mexico. With mild winter weather and an ample supply of oil stocks, prices declined in late 2004 but rebounded in January and February 2005 following global supply outages, colder weather in the U.S. Northeast and Europe and continued disruptions of Iraqi exports. As described under "Hedging Activities" below, we use commodity price hedging instruments to reduce our exposure to oil price fluctuations. The following are comparative average oil prices for the last three years:

	Year Ended December 31		
(per Bbl)	2004	2003	2002
Average NYMEX price	$ 41.38	$ 31.08	$ 26.10
Average realized sales price	$ 38.38	$ 28.59	$ 24.24
Average realized sales price excluding hedging	$ 40.24	$ 29.40	$ 24.52

At February 25, 2005, the average NYMEX oil price for the following 12 months was $50.62 per Bbl. After considering hedges in place as of February 25, 2005, we estimate that a $1.00 per barrel increase or decrease in the average oil sales price would result in approximately a $6 million change in 2005 annual operating cash flow before income taxes.

Hedging Activities. We enter futures contracts, collars and basis swap agreements, as well as fixed price physical delivery contracts, to hedge our exposure to product price volatility. Our policy is to routinely hedge a portion of our production. While there is a risk we may not be able to realize the full benefit of rising prices, management plans to continue its hedging strategy because of the benefits of more predictable production growth and cash flows.

In 2004, all hedging activities decreased gas revenue by $156.1 million and decreased oil revenue by $15.5 million, while in 2003, all hedging activities decreased gas revenue by $193 million and decreased oil revenue by $3.9 million, and in 2002, hedging activities increased gas revenue by $95.4 million and decreased oil revenue by $1.3 million.

The following summarizes our January 2005 through December 2005 NYMEX hedging positions at February 25, 2005, excluding basis adjustments which are separately hedged. Our average daily production was 915,905 Mcf of gas and 33,494 Bbls of oil in fourth quarter 2004. Prices to be realized for hedged production will be less than these NYMEX prices because of location, quality and other adjustments. See Note 8 to the Consolidated Financial Statements.

Futures Contracts and Swap Agreements
for January through December 2005 Production

Natural Gas		Crude Oil	
Mcf per Day	Average NYMEX Price per Mcf	Bbl per Day	Average NYMEX Price per Bbl
250,000	$ 5.90	10,000	$ 35.91
		5,000	$ 43.28

Derivative Fair Value Gain/Loss. We record in our income statements realized and unrealized derivative fair value gains and losses related to derivatives that do not qualify for hedge accounting, as well as the ineffective portion of hedge derivatives. We recorded an $11.9 million loss is 2004, a $10.2 million loss in 2003 and a $2.6 million gain in 2002 related to changes in fair value of these non-hedge derivatives. The 2004 loss includes a $12.5 million loss on the ineffective portion of hedge derivatives, or approximately 8% of total hedge derivative losses, while the 2003 loss includes a $7.3 million loss on the ineffective portion of hedge derivatives, or approximately 4% of total hedge derivative losses. Netted in the 2002 derivative fair value gain is a $2.9 million loss on the ineffective portion of hedge derivatives, or approximately 2% of total hedge derivative losses. These ineffective hedge derivative losses are primarily because of increasing oil and gas prices and their effect on hedges of production in areas without corresponding basis or location differential swap contracts.

Unrealized derivative gains and losses associated with effective cash flow hedges are recorded in stockholders' equity as accumulated other comprehensive income (loss). At December 31, 2004, we have an unrealized pre-tax loss of $45.1 million in accumulated other comprehensive income (loss) related to the fair value of derivatives designated as cash flow hedges of gas and crude oil price risk. This fair value loss is expected to be reclassified into earnings through December 2005. The actual reclassification to earnings will be based on mark-to-market prices at contract settlement date.

Stock-based Incentive Compensation. Incentive compensation generally results from vesting of performance share awards as our common stock price increases. Incentive compensation totaled $89.5 million in 2004, $53.1 million in 2003 and $27 million in 2002, which relates to increases in our stock price of 56% in 2004, 53% in 2003 and 41% in 2002. Included in 2004 incentive compensation is $22.3 million cash compensation related to vesting of cash-equivalent performance shares. Otherwise, stock-based compensation was non-cash. After adjusting for the effects of the May 2004 and April 2003 common stock offerings, stock-based incentive compensation was approximately 3% of the increase in market capitalization during each of 2004, 2003 and 2002. As of December 31, 2004, outstanding performance shares comprise 397,500 shares that vest when the common stock price reaches $28.13, 2,533 shares that vest when the common stock price reaches $28.50, and 397,500 shares that vest when the common stock price reaches $31.88. Based on management's estimated probable vesting period, $2.8 million of related stock incentive compensation was accrued at December 31, 2004. All performance shares vested in February 2005 when these target stock prices were attained, resulting in the remaining related non-cash compensation of $21.1 million to be recorded in first quarter 2005.

In December 2004, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 123 (Revised 2004), which requires companies to record compensation expense for all stock awards at fair value effective July 1, 2005. Accordingly, we will begin recording compensation related to stock options in third quarter 2005. See "Accounting Pronouncements" below.

Cross Timbers Royalty Trust Distribution. In August 2003, our Board of Directors declared a dividend of 0.0044 units of Cross Timbers Royalty Trust for each share of our common stock outstanding on September 2, 2003. This dividend, totaling 1,360,000 units, was distributed on September 18, 2003, after which we no longer own any Cross Timbers Royalty Trust units. We recorded this dividend at $28.2 million, or approximately $0.09 per common share, based on the fair market value of the units on the distribution date. After considering the cost of the units, we recorded a gain on distribution of $16.2 million.

Extinguishment of Debt. We purchased and canceled $9.7 million of our 9¼% senior subordinated notes in April 2002, and redeemed the remaining $115.3 million of the 9¼% notes in June 2002. In November 2002, we purchased and canceled $11.8 million of our 8¾% senior subordinated notes and redeemed the remaining $163.2 million of the 8¾% notes in May 2003. As a result of these transactions, we recorded a total pre-tax loss on extinguishment of debt of $9.6 million in 2003 and $8.5 million in 2002, which includes the effects of redemption premium paid and expensing related deferred debt costs.

Enron Corporation Bankruptcy and Settlement. In December 2001, after Enron Corporation filed for bankruptcy, we had recorded a $21.4 million receivable from Enron and a $43.3 million Btu swap contract payable to Enron. In December 2002, we paid Enron Corporation $6 million in settlement of all claims, resulting in recognition of $14.1 million in gas revenue and a $2.1 million gain.

Cumulative Effect of Accounting Change for Asset Retirement Obligation. On January 1, 2003, we adopted SFAS No. 143 by recording a long-term liability for asset retirement obligation of $75.3 million, an increase in property cost of $60.7 million, a reduction of accumulated depreciation, depletion and amortization of $17.3 million and a cumulative effect of accounting change gain, net of tax, of $1.8 million.

Impairment Provision. We evaluate possible impairment of producing properties when conditions warrant. This evaluation is based on an assessment of recoverability of net property costs from estimated future net cash flows from those properties. Estimated future net cash flows are based on management's best estimate of projected oil and gas reserves and prices. We have not recorded impairment of producing properties since a $2 million provision was recorded in 1998. If oil and gas prices significantly decline, we may be required to record impairment provisions for producing properties in the future, which could be material.

Investment Grade Ratings. In January 2004, Standard & Poors upgraded our corporate credit rating to investment grade and all liens on producing properties and other collateral were irrevocably released as security for our revolving credit agreement with commercial banks. As a result, Moody's upgraded our existing senior notes to Ba1 from Ba2 and confirmed our Ba1 senior implied rating. In March 2004, Moody's upgraded our issuer rating and senior implied rating to Baa3.

Senior Note Offering. In April 2002, we sold $350 million of 7½% senior notes due April 2012, and in April 2003, we sold $400 million of 6¼% senior notes due April 2013. In January 2004, we sold $500 million of 4.9% senior notes due February 2014. In September 2004, we sold $350 million of 5% senior notes due in January 2015. Proceeds from the senior notes were used to fund property acquisitions, redeem senior subordinated notes and reduce bank debt.

Common Stock Transactions. In April 2003, we completed a public offering of 23 million shares of common stock at $11.25 per share, with net proceeds of approximately $248 million. The proceeds and net proceeds from the concurrent sale of senior notes were used to fund our producing property acquisition from Williams, to redeem our 8¾% senior subordinated notes and to reduce bank debt. In May 2004, we completed a public offering of 31.7 million shares of common stock at $18.92 per share. Net proceeds of $580 million were used to reduce bank borrowings that funded our producing property acquisitions from ExxonMobil Corporation and our deposit on the ChevronTexaco acquisition.

Shelf Registration Statement. In February 2005, we filed a shelf registration statement with the Securities and Exchange Commission to potentially offer securities which could include debt securities, preferred stock, common stock, or warrants to purchase debt or stock. The total face amount of securities that can be offered is $2.5 billion, at prices and on terms to be determined at the time of sale. Net proceeds from the sale of such securities will be used for general corporate purposes, including reduction of bank debt.

Results of Operations

2004 Compared to 2003

For the year 2004, net income was $507.9 million compared with net income of $288.3 million for 2003. Earnings for 2004 include the net after-tax effects of stock-based incentive compensation of $55.5 million, special bonuses totaling $11.7 million related to acquisitions announced in second quarter 2004, and a $7.4 million derivative fair value loss. Earnings for 2003 include the net after-tax effects of non-cash incentive compensation of $34.5 million, loss on extinguishment of debt of $6.2 million, a $6.6 million derivative fair value loss, a non-cash contingency gain of $1.1 million, a non-cash gain of $10.5 million resulting from the distribution of Cross Timbers Royalty Trust units as a dividend to common stockholders and a $1.8 million gain on the cumulative effect of the accounting change for adoption of SFAS No. 143 for asset retirement obligation.

Revenues for 2004 were $1.95 billion, or 64% higher than 2003 revenues of $1.19 billion. Gas and natural gas liquids revenue increased $572.8 million, or 55%, because of a 25% increase in gas production and a 24% increase in gas prices from an average of $4.07 per Mcf in 2003 to $5.04 in 2004, as well as a 32% increase in natural gas liquids prices from an average price of $19.99 per Bbl in 2003 to $26.44 in 2004 and a 16% increase in natural gas liquids production (see "Significant Events, Transactions and Conditions – Product Prices – Gas" above). Increased production was attributable to the 2004 acquisition and development program.

Oil revenue increased $183.7 million, or 136%, primarily because of a 75% increase in production, primarily due to acquisitions, and a 34% increase in oil prices from an average of $28.59 per Bbl in 2003 to $38.38 in 2004 (see "Significant Events, Transactions and Conditions – Product Prices – Oil" above). Gas gathering, processing and marketing revenues increased $5.4 million primarily because of higher natural gas liquids prices and margins.

Expenses for 2004 totaled $1.03 billion as compared with total 2003 expenses of $687.9 million. Most expenses increased in 2004 because of increased production from acquisitions and development and related Company growth. Production expense increased $81 million, or 49%, primarily because of increased production and maintenance.

The production expense per Mcfe increase from $0.58 in 2003 to $0.66 in 2004 is primarily attributable to the 75% increase in oil production, which is more expensive to produce than natural gas. Taxes, transportation and other expense, which is generally based on product revenue, increased 66%, or $69.4 million, primarily because of significantly higher oil and gas prices and increased production. Taxes, transportation and other per Mcfe increased 27% from $0.37 in 2003 to $0.47 in 2004 primarily due to higher product prices. Exploration expense increased $8.7 million primarily because of 2004 seismic studies conducted in the Barnett Shale and East Texas.

Depreciation, depletion and amortization (DD&A) increased $122.7 million, or 43%, primarily because of increased production and higher acquisition costs. On an Mcfe basis, DD&A increased from $0.99 in 2003 to $1.09 in 2004 because of higher acquisition and development costs.

General and administrative expense increased $57.4 million, or 53%, primarily because of an increase of $36.4 million in stock-based incentive compensation from $53.1 million to $89.5 million, of which $67.2 million is non-cash. General and administrative expense for the year also includes a total of $11.7 million in special bonuses related to the ChevronTexaco and ExxonMobil acquisitions announced in second quarter 2004 and other increased expenses from Company growth. Excluding stock-based incentive compensation, general and administrative expense per Mcfe increased 5% from $0.19 in 2003 to $0.20 in 2004.

The derivative fair value loss for 2004 was $11.9 million compared to the 2003 derivative fair value loss of $10.2 million. This loss is primarily related to the ineffective portion of hedge derivatives as well as the effect of higher gas prices on the fair value of Btu swap contracts. See Note 7 to Consolidated Financial Statements.

Interest expense increased $29.9 million, or 47%, primarily because of a 46% increase in the weighted average borrowings to partially fund property acquisitions. Interest expense per Mcfe increased 14% from $0.22 in 2003 to $0.25 in 2004.

2003 Compared to 2002

For the year 2003, net income was $288.3 million compared with net income of $186.1 million for 2002. Earnings for 2003 include the net after-tax effects of non-cash incentive compensation of $34.5 million, loss on extinguishment of debt of $6.2 million, a $6.6 million derivative fair value loss, a non-cash contingency gain of $1.1 million, a non-cash gain of $10.5 million resulting from the distribution of Cross Timbers Royalty Trust units as a dividend to common stockholders and a $1.8 million gain on the cumulative effect of the accounting change for adoption of SFAS No. 143 for asset retirement obligation. Earnings for 2002 include a $17.5 million after-tax charge for non-cash incentive compensation, a $5.5 million after-tax charge for extinguishment of debt, a $1.3 million after-tax gain on a settlement with Enron Corporation and a $1.7 million after-tax derivative fair value gain.

Revenues for 2003 were $1.19 billion, or 47% higher than 2002 revenues of $810.2 million. Gas and natural gas liquids revenue increased $359.2 million, or 53%, because of a 30% increase in gas production and a 17% increase in gas prices from an average of $3.49 per Mcf in 2002 to $4.07 in 2003, as well as a 40% increase in natural gas liquids prices from an average price of $14.31 per Bbl in 2002 to $19.99 in 2003 and a 28% increase in natural gas liquids production (see "Significant Events, Transactions and Conditions – Product Prices – Gas" above). Increased production was attributable to the 2003 acquisition and development program.

Oil revenue increased $19.7 million, or 17%, primarily because of an 18% increase in oil prices from an average of $24.24 per Bbl in 2002 to $28.59 in 2003 (see "Significant Events, Transactions and Conditions – Product Prices – Oil" above). A 1% decrease in production was the result of natural decline, partially offset by development. Gas gathering, processing and marketing revenues increased $1.4 million primarily because of higher natural gas liquids prices and margins. Other revenues of $2.1 million in 2002 represent the gain on a settlement with Enron Corporation.

Expenses for 2003 totaled $687.9 million as compared with total 2002 expenses of $461.3 million. Most expenses increased in 2003 because of increased production from acquisitions and development and related Company growth. Production expense increased $35.7 million, or 28%, because of higher production related to acquisitions and development. Production expense per Mcfe increased slightly from $0.57 in 2002 to $0.58 in 2003 because of increased fuel costs. Taxes, transportation and other increased 83%, or $47.4 million, primarily because of significantly higher oil and gas prices, increased production, higher transportation fuel prices and higher property taxes related to drilling and acquisitions. Taxes, transportation and other per Mcfe increased 48% from $0.25 in 2002 to $0.37 in 2003 primarily due to higher product prices.

DD&A increased $79.9 million, or 39%, primarily because of increased production and higher acquisition costs. On an Mcfe basis, DD&A increased from $0.90 in 2002 to $0.99 in 2003 because of higher acquisition and development costs.

General and administrative expense increased $45.6 million, or 73%, because of an increase of $26.1 million in stock-based incentive compensation and increased expenses from Company growth. Excluding this non-cash incentive compensation, general and administrative expense per Mcfe increased 27% from $0.15 in 2002 to $0.19 in 2003.

The derivative fair value loss for 2003 was $10.2 million compared to 2002 derivative fair value gain of $2.6 million. The 2003 loss is primarily related to the effect of higher gas prices on the fair value of Btu swap contracts and the ineffective portion of hedge derivatives. The 2002 gain is primarily the result of declining gas prices on derivatives that do not qualify for hedge accounting. See Note 7 to Consolidated Financial Statements.

Interest expense increased $10.2 million, or 19%, primarily because of a 24% increase in the weighted average borrowings to partially fund property acquisitions, offset by a 6% decrease in the weighted average interest rate. Interest expense per Mcfe decreased 8% from $0.24 in 2002 to $0.22 in 2003 because higher production offset increased borrowings.

During 2003, we recognized a $9.6 million loss on extinguishment of debt related to the redemption of our $8\frac{3}{4}$% senior subordinated notes, compared with the recognition in 2002 of an $8.5 million loss on extinguishment of debt primarily related to the redemption of our $9\frac{1}{4}$% senior subordinated notes. See Note 3 to Consolidated Financial Statements. During 2003, we also recognized a $16.2 million gain on the distribution of Cross Timbers Royalty Trust units as a dividend to common stockholders.

Liquidity and Capital Resources

Our primary sources of liquidity are cash flow from operating activities, borrowings against the revolving credit facility, occasional producing property sales (including sales of royalty trust units) and private or public offerings of equity and debt. Other than for operations, our cash requirements are generally for the acquisition, exploration and development of oil and gas properties, and debt and dividend payments. Exploration and development expenditures and dividend payments have generally been funded by cash flow from operations. We believe that our sources of liquidity are adequate to fund our cash requirements in 2005.

Cash provided by operating activities was $1.22 billion in 2004, compared with cash provided by operating activities of $794.2 million in 2003 and $490.8 million in 2002. Increased cash provided by operating activities from 2003 to 2004 and from 2002 to 2003 was primarily because of increased prices and production from acquisitions and development activity. Cash provided by operating activities was decreased by changes in operating assets and liabilities of $58.2 million in 2004 and $22.9 million in 2002 and was increased by changes in operating assets and liabilities of $3.7 million in 2003. Changes in operating assets and liabilities are primarily the result of timing of cash receipts and disbursements. Cash provided by operating activities was also reduced by exploration expense of $10.5 million in 2004, $1.8 million in 2003 and $2.2 million in 2002. Cash provided by operating activities is largely dependent upon the prices received for oil and gas production. As of February 2005, we have hedged approximately 25% of our projected 2005 gas production and about 45% of our projected 2005 crude oil production. See "Significant Events, Transactions and Conditions - Product Prices" above.

We do not have any investments in unconsolidated entities or persons that could materially affect the liquidity or the availability of capital resources.

Financial Condition

Total assets increased 69% from $3.6 billion at December 31, 2003 to $6.1 billion at December 31, 2004, primarily because of Company growth related to acquisitions and development. As of December 31, 2004, total capitalization was $4.6 billion, of which 44% was long-term debt. Capitalization at December 31, 2003 was $2.7 billion, of which 46% was long-term debt. The decrease in the debt-to-capitalization ratio from year-end 2003 to 2004 is primarily because of our earnings for the year.

Working Capital

We generally maintain low cash and cash equivalent balances because we use available funds to reduce bank debt. Short-term liquidity needs are satisfied by bank commitments under the loan agreement (see "Financing" below). Because of this, and since our principal source of operating cash flows (i.e., proved reserves to be produced in the following year) cannot be reported as working capital, we often have low or negative working capital. Working capital decreased from a negative position of $59.4 million at December 31, 2003 to negative working capital of $64 million at December 31, 2004. Excluding the effects of current derivative and deferred tax assets and liabilities, working capital decreased $19.2 million. This decrease is because of increased accounts payable and accrued liabilities primarily related to increased production and drilling liabilities, partially offset by increased accounts receivable related to increased revenues. Any cash settlement of hedge derivatives should generally be offset by increased or decreased cash flows from our sales of related production. Therefore, we believe that most of the changes in derivative fair value assets and liabilities are offset by changes in value of our oil and gas reserves. This offsetting change in value of oil and gas reserves, however, is not recorded in the financial statements.

None of our derivative contracts have margin requirements or collateral provisions that could require funding prior to the scheduled cash settlement date. When the monthly cash settlement amount under our hedge derivatives is calculated, if market prices are higher than the fixed contract prices, we are required to pay the contract counterparties. While this payment will ultimately be funded by higher prices received from sale of our production, production receipts lag payments to the counterparties by as much as 55 days. Any interim cash needs are funded by borrowings under our revolving credit agreement.

Most of our receivables are from a diverse group of companies including major energy companies, pipeline companies, local distribution companies and end-users in various industries. We currently have greater concentrations of credit with several A- or better rated integrated energy companies. Financial and commodity-based futures and swap contracts expose us to the credit risk of nonperformance by the counterparty to the contracts. This exposure is diversified among major investment grade financial institutions, and we have master netting agreements with counterparties that provide for offsetting payables against receivables from separate derivative contracts. Letters of credit or other appropriate forms of security are obtained as considered necessary to limit risk of loss.

Financing

In February 2004, we entered a five-year revolving credit agreement with commercial banks that matures in February 2009. The agreement currently provides for a maximum commitment amount of $1 billion, and an interest rate based on the London Interbank Offered Rate ("LIBOR") plus 1%. The agreement requires us to maintain a debt-to-total capitalization ratio of not more than 60%. On December 31, 2004, borrowings under the revolving credit agreement with commercial banks were $146 million at a weighted average interest rate of 3.49%, and with unused borrowing capacity of $854 million.

In November 2004, we entered a new $300 million five-year term loan due April 2010 with an initial interest rate of LIBOR plus 0.75%. Other terms and conditions are substantially the same as our existing revolving credit agreement. As of December 31, 2004, borrowings under the term loan were $300 million.

In February 2005, we filed a shelf registration statement with the Securities and Exchange Commission to potentially offer securities which could include debt securities, preferred stock, common stock or warrants to purchase debt or stock. The total face amount of securities that can be offered is $2.5 billion, at prices and on terms to be determined at the time of sale. Net proceeds from the sale of such securities will be used for general corporate purposes, including reduction of bank debt.

Capital Expenditures

In 2004, exploration and development cash expenditures totaled $610 million compared with $461.6 million in 2003. We have budgeted $850 million for the 2005 development and exploration program. As we have done historically, we expect to fund the 2005 development program with cash flow from operations. Since there are no material long-term commitments associated with this budget, we have the flexibility to adjust our actual development expenditures in response to changes in product prices, industry conditions and the effects of our acquisition and development programs.

The weak U.S. dollar, raw material shortages and strong global demand for steel have continued to tighten steel supplies and cause prices to remain high. In response, we have increased our tubular inventory and have negotiated supply contracts with our vendors to support our development program. While we expect to acquire adequate supplies to complete our development program, a further tightening of steel supplies could restrain the program, limiting production growth and increasing development costs.

While an acquisition budget has not been formalized, we plan to actively review additional acquisition opportunities during 2005. If acquisition, development and exploration expenditures exceed cash flow from operations, we expect to obtain additional funding through our bank credit facilities, issuance of public or private debt or equity, or asset sales. There are no restrictions under our revolving credit agreement that would affect our ability to use our remaining borrowing capacity for acquisitions of producing properties.

To date, we have not spent significant amounts to comply with environmental or safety regulations, and we do not expect to do so during 2005. However, new regulations, enforcement policies, claims for damages or other events could result in significant future costs.

Dividends

The Board of Directors declared quarterly dividends of $0.0045 per common share each quarter of 2002, $0.006 per common share each quarter of 2003, $0.0075 per common share for first and second quarter 2004 and $0.0375 per common share for the remainder of 2004. In February 2005, the Board increased the dividend rate 33% by declaring a first quarter 2005 dividend of $0.05 per common share after the four-for-three stock split is effected on March 15, 2005. In August 2003, the Board also declared a dividend of 0.0044 units of Cross Timbers Royalty Trust for each share of our common stock outstanding on September 2, 2003. The market value at the date of distribution was approximately $0.09 per common share. Our ability to pay dividends is dependent upon our financial condition, earnings and cash flow from operations, the level of our capital expenditures, our future business prospects and other matters our Board of Directors deems relevant.

Income Taxes

We have estimated that all our net operating loss carryforwards will be fully utilized as of December 31, 2004. Although our alternative minimum tax credit carryforwards of $37.8 million have no expiration date, we expect to utilize these carryforwards in 2005.

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

The following summarizes our significant obligations and commitments to make future contractual payments as of December 31, 2004. We have not guaranteed the debt or obligations of any other party, nor do we have any other arrangements or relationships with other entities that could potentially result in unconsolidated debt or losses.

		Payments Due by Year					
(in thousands)	Total	2005	2006	2007	2008	2009	After 2009
Long-term debt	$ 2,046,000	$ –	$ –	$ –	$ –	$ 146,000	$ 1,900,000
Operating leases	151,123	30,200	23,882	22,806	18,605	15,964	39,666
Drilling contracts	99,085	99,085	–	–	–	–	–
Transportation contracts	137,341	21,935	22,463	19,741	18,804	18,030	36,368
Purchase obligations	10,300	10,300	–	–	–	–	–
Derivative contract liabilities at December 31, 2004 fair value	86,713	75,534	11,179	–	–	–	–
Total	$ 2,530,562	$ 237,054	$ 57,524	$ 42,547	$ 37,409	$ 179,994	$ 1,976,034

Long-Term Debt. At December 31, 2004, borrowings were $146 million under our senior bank revolving credit facility due in February 2009, as reflected in the table above. Borrowings of $300 million under our term bank facility are due in April 2010, and our senior notes, totaling $1.6 billion at December 31, 2004, are due in 2012 through 2015. For further information regarding long-term debt, see Note 3 to Consolidated Financial Statements.

Transportation Contracts. We have entered firm transportation contracts with various pipelines. Under these contracts we are obligated to transport minimum daily gas volumes or pay for any deficiencies at a specified reservation fee rate. As calculated on a monthly basis, our failure to deliver these minimum volumes to the pipeline requires us to pay the pipeline for any deficiency. Our production committed to these pipelines is expected to exceed the minimum daily volumes provided in the contracts. We have generally delivered at least minimum volumes under these firm transportation contracts, therefore avoiding payment for deficiencies.

Purchase Obligations. We have agreed to acquire an airplane for $17.1 million, either through purchase or lease, and have made an initial payment of $6.8 million in 2004. We currently expect to take delivery of the airplane in the first half of 2005. This obligation is reflected as a purchase in the table above, net of the amount paid in 2004.

Derivative Contracts. We have entered into futures contracts and swaps to hedge our exposure to oil and natural gas price fluctuations. As of December 31, 2004, market prices generally exceeded the fixed prices specified by these contracts, resulting in a derivative fair value current liability of $75.5 million and long-term liability of $11.2 million. If market prices are higher than the contract prices when the cash settlement amount is calculated, we are required to pay the contract counterparties. While such payments generally will be funded by higher prices received from the sale of our production, production receipts may be received as much as 55 days after payment to counterparties and can result in draws on our revolving credit facility. See Note 8 to Consolidated Financial Statements.

POST-RETIREMENT PLANS

We have a retiree medical plan that provides retired employees and directors with health care benefits similar to those provided employees. Employees and directors are eligible to receive benefits when their combined age and years of qualified service total 60, with a minimum age of 45 and a minimum of five years of service. Otherwise, retirement benefits are only provided through our defined contribution 401(k) plan. Post-retirement medical benefits are not prefunded but are paid when incurred. Our periodic benefit cost recorded for 2004 was $632,000 and is expected to be approximately $1 million in 2005. Future benefit costs will be affected by fluctuations in interest rates and health care cost trends. We do not currently anticipate that retiree medical plan costs will be significant in relation to the Company's future financial position, results of operations or cash flows.

RELATED PARTY TRANSACTIONS

A firm, partially owned by one of our directors, has performed property acquisition advisory services for the Company. We paid this firm total fees of $8.8 million in 2004 and $2.4 million in 2002, and there were no amounts payable at December 31, 2004 or 2003. No fees were paid to this firm in 2003. This same director-related company represented the seller of properties for acquisitions totaling approximately $186 million that we closed in January 2004. In February 2005, this firm was acquired by another company with which we expect to continue to have a relationship.

A portion of the producing properties obtained in the ChevronTexaco acquisition were considered nonstrategic and marked for disposition at the time of purchase. In August 2004, we exchanged $37.8 million of these properties for 19,000 net contiguous acres in our new core operating area, the Barnett Shale of North Texas, and $25.4 million in other consideration. This exchange was with companies either wholly or majority owned by the adult children and a brother of Bob R. Simpson, Chairman and Chief Executive Officer of the Company. In connection with this exchange, we granted these companies an option to purchase other properties included in the ChevronTexaco acquisition. On March 1, 2005, these companies purchased the properties for an adjusted purchase price of $11.5 million. Lehman Brothers Inc. provided a fairness opinion to the Board of Directors on the value of properties exchanged and sold.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Our financial position and results of operations are significantly affected by accounting policies and estimates related to our oil and gas properties, proved reserves, asset retirement obligation and commodity prices and risk management, as summarized below.

Oil and Gas Property Accounting

Oil and gas exploration and production companies may elect to account for their property costs using either the "successful efforts" or "full cost" accounting method. Under the successful efforts method, unsuccessful exploratory well costs, as well as all exploratory geological and geophysical costs, are expensed. Under the full cost method, all exploration costs are capitalized, regardless of success. Selection of the oil and gas accounting method can have a significant impact on a company's financial results. We use the successful efforts method of accounting and generally pursue acquisitions and development of proved reserves as opposed to exploration activities.

In accordance with Statement of Financial Accounting Standards No. 144, we evaluate possible impairment of producing properties when conditions indicate that the properties may be impaired. Such conditions include a significant decline in product prices which we believe to be other than temporary or a significant downward revision in estimated proved reserves for a field or area. Our estimates of cash flows are based on the latest available proved reserve and production information and management's estimates of future product prices and costs, based on available information such as forward strip prices and industry forecasts and analysis. An impairment provision must be recorded to adjust the net book value of the property to its estimated fair value if the net book value exceeds the estimated future net cash flows from the property. The estimated fair value of the property is generally calculated as the discounted present value of future net cash flows.

The impairment assessment process is primarily dependent upon the estimate of proved reserves. Any overstatement of estimated proved reserve quantities would result in an overstatement of estimated future net cash flows, which could result in an understated assessment of impairment. The subjectivity and risks associated with estimating proved reserves are discussed under "Oil and Gas Reserves" below. Prediction of product prices is subjective since prices are largely dependent upon supply and demand resulting from global and national conditions generally beyond our control. However, management's assessment of product prices for purposes of impairment is consistent with that used in its business plans and investment decisions. While there is judgment involved in management's estimate of future product prices, the potential impact on impairment is not currently significant since current and projected product prices are substantially higher than our net acquisition and development costs per Mcfe. Because of this, our historical impairment of producing properties has been limited to a $2 million provision in 1998, and we do not currently expect significant future impairment unless product prices were to decline and remain at levels substantially below current levels. We believe that a sensitivity analysis regarding the effect of changes in assumptions on estimated impairment is impracticable to provide because of the number of assumptions and variables involved which have interdependent effects on the potential outcome.

Oil and Gas Reserves

Our proved oil and gas reserves are estimated by independent petroleum engineers. Reserve engineering is a subjective process that is dependent upon the quality of available data and the interpretation thereof, including evaluations and extrapolations of well flow rates and reservoir pressure. Estimates by different engineers often vary, sometimes significantly. In addition, physical factors such as the results of drilling, testing and production subsequent to the date of an estimate, as well as economic factors such as changes in product prices, may justify revision of such estimates. Because proved reserves are required to be estimated using prices at the date of the evaluation, estimated reserve quantities can be significantly impacted by changes in product prices.

Proved reserves, as defined by the Financial Accounting Standards Board and adopted by the Securities and Exchange Commission, are limited to reservoir areas that indicate economic producibility through actual production or conclusive formation tests, and generally cannot extend beyond the immediately adjoining undrilled portion. Although improved technology often can identify possible or probable reserves other than by drilling, these reserves cannot be estimated and disclosed.

Depreciation, depletion and amortization of producing properties is computed on the unit-of-production method based on estimated proved oil and gas reserves. While total DD&A expense for the life of a property is limited to the property's total cost, proved reserve revisions result in a change in timing of when DD&A expense is recognized. Downward revisions of proved reserves result in an acceleration of DD&A expense, while upward revisions tend to lower the rate of DD&A expense recognition. As shown in Note 15 to the Consolidated Financial Statements, net upward revisions occurred to proved reserves on an Mcfe basis in 2002 and 2003, resulting in a decrease of DD&A expense of approximately 4%, or $8 million, in 2002 and 1%, or $2 million, in 2003. Net downward revisions of proved reserves on an Mcfe basis occurred in 2004, resulting in an increase in DD&A expense of approximately 2%, or $7 million. Based on proved reserves at December 31, 2004, we estimate that a 1% change in proved reserves would increase or decrease 2005 DD&A expense by approximately $4 million.

During 2004, development and exploration activities resulted in extensions, additions, discoveries and net revisions of proved reserves that were 195% of our 2004 production. Over the last five years, our proved reserve extensions, additions, discoveries and net revisions averaged 220% of our production for this period. Our proved reserve extensions, additions and discoveries in 2004 included an increase of 637.6 Bcfe in proved undeveloped reserves, or approximately 80% of our total extensions, additions and discoveries, which are expected to be developed within three years. Over the past four years, approximately 80% of our proved reserves extensions, additions and discoveries were proved undeveloped reserves which were generally reclassified to proved developed reserves within three years. Development of our proved undeveloped reserves is not subject to significant uncertainties such as regulatory approvals, and we believe that we have adequate resources to develop these reserves, dependent on commodity prices not declining significantly. We believe that reserve additions, comparable to these historical reserve additions, are attainable in the near term future, subject to product prices and development costs remaining at levels to ensure economic viability.

The standardized measure of discounted future net cash flows and changes in such cash flows, as reported in Note 15 to Consolidated Financial Statements, are prepared using assumptions required by the Financial Accounting Standards Board and the Securities and Exchange Commission. Such assumptions include using year-end oil and gas prices and year-end costs for estimated future development and production expenditures. Discounted future net cash flows are calculated using a 10% rate. Changes in any of these assumptions could have a significant impact on the standardized measure. Accordingly, the standardized measure does not represent management's estimated current market value of proved reserves.

Asset Retirement Obligation

Effective January 1, 2003, we adopted SFAS No. 143, *Accounting for Asset Retirement Obligations*. Our asset retirement obligation primarily represents the estimated present value of the amount we will incur to plug, abandon and remediate our producing properties (including removal of our offshore platforms in Alaska) at the end of their productive lives, in accordance with applicable state laws. We determine our asset retirement obligation by calculating the present value of estimated cash flows related to the liability. The retirement obligation is recorded as a liability at its estimated present value as of the asset's inception, with an offsetting increase to producing properties. Periodic accretion of discount of the estimated liability is recorded as an expense in the income statement.

Our liability is determined using significant assumptions, including current estimates of plugging and abandonment costs, annual inflation of these costs, the productive lives of wells and our risk-adjusted interest rate. Changes in any of these assumptions can result in significant revisions to the estimated asset retirement obligation. For example, as we analyze actual plugging and abandonment information, we may revise our estimates of current costs, the assumed annual inflation of these costs and/or the assumed productive lives of our wells. During 2004, we increased our estimated asset retirement obligation by $6 million, or approximately 6% of the asset retirement obligation at December 31, 2003, based on a review of current plugging and abandonment costs. Revisions to the asset retirement obligation are recorded with an offsetting change to producing properties, resulting in prospective changes to depreciation, depletion and amortization expense and accretion of discount. Because of the subjectivity of assumptions and the relatively long lives of most of our wells, the costs to ultimately retire our wells may vary significantly from prior estimates.

Commodity Prices and Risk Management

Commodity prices significantly affect our operating results, financial condition, cash flows and ability to borrow funds. Current market oil and gas prices are affected by supply and demand as well as seasonal, political and other conditions which we generally cannot control. Oil and gas prices and markets are expected to continue their historical volatility. See "Significant Events, Transactions and Conditions – Product Prices" above.

We attempt to reduce our price risk on a portion of our production by entering into financial instruments such as futures contracts, collars and basis swap agreements, as well as fixed price physical delivery contracts. While these instruments secure a certain price and, therefore, a certain cash flow, there is the risk that we may not be able to realize the full benefit of rising prices. These contracts also expose us to credit risk of nonperformance by the contract counterparties, all of which are major investment grade financial institutions. We attempt to limit our credit risk by obtaining letters of credit or other appropriate forms of security. We also have sold call options as part of our hedging program. Call options, however, do not provide a hedge against declining prices, and there is the risk that the call sales proceeds will be less than the benefit a higher sales price would have provided.

While our price risk management activities decrease the volatility of cash flows, they may obscure our reported financial condition. As required under generally accepted accounting principles, we record derivative financial instruments at their fair value, representing projected gains and losses to be realized upon settlement of these contracts in subsequent periods when related production occurs. These gains and losses are generally offset by increases and decreases in the market value of our proved reserves, which are not reflected in the financial statements. Derivatives that provide effective cash flow hedges are designated as hedges, and, to the extent the hedge is determined to be effective, we defer related unrealized fair value gains and losses in accumulated other comprehensive income until the hedged transaction occurs. See "Derivatives" under Note 1 to Consolidated Financial Statements regarding our accounting policy related to derivatives.

See also "Commodity Price Risk" under Item 7A, Quantitative and Qualitative Disclosures about Market Risk, for the effect of price changes on derivative fair value gains and losses.

Accounting Pronouncements

In December 2004, the Financial Accounting Standards Board issued SFAS No. 153, *Exchanges of Nonmonetary Assets, an Amendment of APB Opinion No. 29*, which provides that all nonmonetary asset exchanges that have commercial substance must be measured based on the fair value of the assets exchanged, and any resulting gain or loss recorded. An exchange is defined as having commercial substance if it results in a significant change in expected future cash flows. Exchanges of operating interests by oil and gas producing companies to form a joint venture continue to be exempted. APB Opinion 29 previously exempted all exchanges of similar productive assets from fair value accounting, therefore resulting in no gain or loss recorded for such exchanges. We must implement SFAS 153 for any nonmonetary asset exchanges occurring on or after January 1, 2006. This change in accounting is currently not expected to have a significant effect on our reported financial position or earnings.

In December 2004, the FASB issued Staff Position FAS 109-1 that concluded that the special tax deduction allowed under the American Jobs Creation Act of 2004 should be accounted for as a "special deduction" instead of a tax rate reduction as provided by SFAS 109. Accordingly, any tax relief the Company receives under the new tax law will be recorded as a reduction of current tax when realized, rather than an immediate reduction to its accrued deferred income tax liability.

Also in December 2004, the FASB issued SFAS No. 123 (Revised 2004), *Share-Based Payment*, which requires that compensation related to all stock-based awards, including stock options, be recognized in the financial statements. This pronouncement replaces SFAS No. 123, *Accounting for Stock-Based Compensation*, and supersedes APB Opinion No. 25, *Accounting for Stock Issued to Employees*, and will be effective beginning July 1, 2005. We have previously recorded stock compensation pursuant to the intrinsic value method under APB No. 25, whereby no compensation was recognized for most stock option awards. We expect that stock option grants will continue to be a significant part of employee compensation, and, therefore, SFAS No. 123R will have a significant impact on our financial statements. For the pro forma effect of recording compensation for all stock awards at fair value, utilizing the Black-Scholes method, see *Stock-Based Compensation* in Note 1 to Consolidated Financial Statements. We are currently considering alternative valuation methods to determine stock award fair value for grants after June 30, 2005. We plan to use the modified prospective application method of adopting SFAS No. 123R, whereby the estimated fair value of unvested stock awards granted prior to July 1, 2005 will be recognized as compensation expense in periods subsequent to June 30, 2005, based on the estimated service period. The fair value of awards granted prior to July 1, 2005 will be the same value as determined under the Black–Scholes method for our pro forma disclosure. As of February 22, 2005, all stock options outstanding at that date vested when the common stock price closed above the target price level of $31.88, resulting in no compensation expense to be recognized after June 30, 2005 related to these awards.

In February 2005, the staff of the Securities and Exchange Commission sent a letter to oil and gas registrants regarding situations that require additional financial statement disclosures, pending final resolution of accounting treatment. The following are items related to registrants using the successful efforts method of accounting:

- Companies may enter concurrent commodity buy/sale arrangements, or transactions in contemplation of other transactions, often to assure that the commodity is available at a specific location. Pending resolution of accounting questions with the Emerging Issues Task Force, the Commission staff has requested additional disclosures for any such material arrangements, including separate disclosure on the face of the income statement of any related proceeds and costs reported on a gross basis. These disclosures are not applicable to us since we have not entered any significant transactions of this nature.
- Statement of Financial Accounting Standards No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies*, specifies that drilling costs for completed exploratory wells should be expensed if the related reserves cannot be classified as proved within one year unless certain criteria are met. Rather than specifying this one-year requirement, a proposed FASB Staff Position has been issued that provides guidance for evaluating whether sufficient progress is being made to determine whether reserves can be classified as proved. Pending approval of the FASB Staff Position, the Commission staff has requested additional disclosures be included in registrants' financial statements regarding their accounting policy for capitalization of exploratory drilling costs, as well as disclosure of capitalized exploratory drilling cost amounts included in the financial statements. As disclosed in Note 1 to Consolidated Financial Statements, we generally pursue development of proved reserves as opposed to exploration activities, and our drill well costs are generally transferred to producing properties within one month of the well completion date. Disclosure of changes in capitalized exploratory well costs is included in Note 15 to Consolidated Financial Statements.

Production Imbalances

We have gas production imbalance positions that are the result of partial interest owners selling more or less than their proportionate share of gas on jointly owned wells. Imbalances are generally settled by disproportionate gas sales over the remaining life of the well, or by cash payment by the overproduced party to the underproduced party. We use the entitlement method of accounting for natural gas sales. Accordingly, revenue is deferred for gas deliveries in excess of our net revenue interest, while revenue is accrued for the undelivered volumes. Production imbalances are generally recorded at the estimated sales price in effect at the time of production. The consolidated balance sheets include the following amounts related to production imbalances:

	December 31			
	2004		2003	
(in thousands)	Amount	Mcf	Amount	Mcf
Accounts receivable - current underproduction	$ 30,780	8,116	$ 23,949	7,135
Accounts payable - current overproduction	(24,087)	(6,388)	(19,366)	(5,900)
Net current gas underproduction balancing receivable	$ 6,693	1,728	$ 4,583	1,235
Other assets - noncurrent underproduction	$ 17,723	4,868	$ 19,385	6,148
Other long-term liabilities - noncurrent overproduction	(33,262)	(9,063)	(29,776)	(9,353)
Net long-term gas overproduction balancing payable	(15,539)	(4,195)	(10,391)	(3,205)
Other assets - noncurrent carbon dioxide underproduction	1,985	12,480	1,977	12,354
Net long-term overproduction balancing payable	$ (13,554)		$ (8,414)	

Certain information included in this annual report and other materials filed or to be filed by us with the Securities and Exchange Commission, as well as information included in oral statements or other written statements made or to be made by us, contain projections and forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934, as amended, and Section 27A of the Securities Act of 1933, as amended, relating to our operations and the oil and gas industry. Such forward-looking statements may be or may concern, among other things, capital expenditures, capital budget, cash flow, drilling activity, drilling locations, acquisition and development activities and funding thereof, production and reserve growth, pricing differentials, reserve potential, operating costs, operating margins, production activities, oil, gas and natural gas liquids reserves and prices, hedging activities and the results thereof, liquidity, debt repayment, unused borrowing capacity, estimated stock award vesting periods, completion of pipelines and processing facilities, regulatory matters and competition. Such forward-looking statements are based on management's current plans, expectations, assumptions, projections and estimates and are identified by words such as "expects," "intends," "plans," "projects," "predicts," "anticipates," "believes," "estimates," "goal," "should," "could," "assume," and similar words that convey the uncertainty of future events. These statements are not guarantees of future performance and involve certain risks, uncertainties and assumptions that are difficult to predict. Therefore, actual results may differ materially from expectations, estimates, or assumptions expressed in, forecasted in, or implied in such forward-looking statements. Some of the risk factors that could cause actual results to differ materially are discussed below.

Oil and Gas Price Fluctuations. Our results of operations depend upon the prices we receive for our oil and gas. Historically, the markets for oil and gas have been volatile and are likely to remain volatile in the future. We routinely hedge a portion of our production to reduce the effects of price volatility (see "Hedging Arrangements" below). Otherwise, the prices we receive depend upon factors beyond our control, including political instability in oil-producing regions, weather conditions, ability of OPEC to agree upon and maintain oil prices and production levels, consumer demand, worldwide economic conditions and the price and availability of alternative fuels. Moreover, government regulations, such as regulation of gas transportation and price controls, can affect product prices in the long term. These external factors and the volatile nature of the energy markets make it difficult to reliably estimate future prices of oil and gas. To the extent we have not hedged our production, any decline in oil and gas prices adversely affects our financial condition. If the oil and gas industry experiences significant price declines, we may, among other things, be unable to meet our financial obligations, make planned capital expenditures or reach production growth targets.

Debt Level. We have substantial debt and may incur more. If we are unsuccessful in increasing production from existing reserves or developing new reserves, we may lack the funds to pay principal and interest on our debt obligations. Our indebtedness also affects our ability to finance future operations and capital needs and may preclude pursuit of other business opportunities.

Capital Requirements. We make, and will continue to make, substantial capital expenditures for the acquisition, development, production, exploration and abandonment of our oil and gas reserves. We intend to finance our capital expenditures primarily through cash flow from operations, bank borrowings and public or private offerings of equity and debt. Lower oil and gas prices, however, may reduce cash flow available to pay down bank borrowings or other debt.

Competitive Industry. The oil and gas industry is highly competitive. We compete with major oil companies, independent oil and gas businesses, and individual producers and operators. In addition, there is competition from alternative energy sources, such as heating oil, imported liquified natural gas and other fossil fuels. Some of our competitors have financial, technological and other resources substantially greater than ours. These companies may be able to pay more for development prospects and productive oil and gas properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. We also compete with these companies for technical, managerial and other professional personnel. Our ability to develop and exploit our oil and gas properties and to acquire additional properties in the future will depend upon our ability to hire and retain qualified personnel, conduct operations, implement advanced technologies, evaluate and select suitable properties, and consummate transactions in this highly competitive environment.

Reserve Replacement. Our success depends upon finding, acquiring and developing oil and gas reserves that are economically recoverable. Unless we are able to successfully explore for, develop or acquire proved reserves, our proved reserves will decline through depletion and our financial assets and annual revenues will decline unless prices substantially increase. We cannot assure the success of our exploration, development and acquisition activities.

Hedging Arrangements. To reduce our exposure to fluctuations in the prices of oil and gas, we currently and may in the future enter into hedging arrangements for a portion of our oil and gas production. These hedging arrangements expose us to risk of financial loss in some circumstances, including when production is less than expected, the counterparty to the hedging contract defaults on its contract obligations, or there is a change in the expected differential between the underlying price in the hedging agreements and actual prices received. In addition, these hedging arrangements may limit the benefit we would otherwise receive from increases in prices for oil and gas.

Reserve Estimates. Estimating our proved reserves involves many uncertainties, including factors beyond our control. Petroleum engineers consider many factors and make assumptions in estimating oil and gas reserves and future net cash flows. Lower oil and gas prices generally cause lower estimates of proved reserves. Ultimately, actual production, revenues and expenditures relating to our reserves will vary from any estimates, and these variations may be material.

Acquiring Producing Properties. We constantly evaluate opportunities to acquire oil and gas properties and frequently engage in bidding and negotiation for these acquisitions. If successful in this process, we may alter or increase our capitalization through the issuance of additional debt or equity securities, the sale of production payments or other measures. Any change in capitalization affects our risk profile. Acquisitions may also alter the nature of our business. This could occur when the character of acquired properties is substantially different from our existing properties in terms of operating or geologic characteristics.

Drilling Activities. Our drilling activities subject us to many risks, including the risk that we will not find commercially productive reservoirs. Drilling for oil and gas can be unprofitable, not only from dry wells, but from productive wells that do not produce sufficient revenues to return a profit. Also, title problems, weather conditions, governmental requirements and shortages or delays in the delivery of equipment and services can delay our drilling operations or result in their cancellation. Shortages of equipment, including pipe, can lead to a delay or suspension of drilling and can significantly increase the cost of drilling. The cost of drilling, completing and operating wells is often uncertain, and we cannot assure that new wells will be productive or that we will recover all or any portion of our investment.

Marketability of Production. The marketability of our production depends in part upon the availability, proximity and capacity of pipelines, gas gathering systems and processing facilities. Any significant change in market factors affecting these infrastructure facilities could harm our business. We deliver some of our oil and gas through gathering systems and pipelines that we do not own. These facilities may not be available to us in the future or access may be limited for extended periods due to maintenance or other curtailment.

Growth through Acquisitions. Our business strategy has emphasized growth through strategic acquisitions, but we may not be able to continue to identify properties for acquisition or we may not be able to make acquisitions on terms that we consider economically acceptable. There is intense competition for acquisition opportunities in our industry. Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. Our strategy of completing acquisitions is dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. Our ability to pursue our growth strategy may be hindered if we are not able to obtain financing or regulatory approvals. Our ability to grow through acquisitions and manage growth will require us to continue to invest in operational, financial and management information systems and to attract, retain, motivate and effectively manage our employees. The inability to effectively manage the integration of acquisitions could reduce our focus on subsequent acquisitions and current operations, which, in turn, could negatively impact our earnings and growth. Our financial position and results of operations may fluctuate significantly from period to period, based on whether or not significant acquisitions are completed in particular periods.

Governmental Regulations. Extensive federal, state and local regulation of the oil and gas industry significantly affects our operations. In particular, our oil and natural gas exploration, development and production, and our storage and transportation of liquid hydrocarbons, are subject to stringent environmental regulations. These regulations have increased the costs of planning, designing, drilling, installing, operating and abandoning oil and natural gas wells and other related facilities. These regulations may become more demanding in the future. Matters subject to regulation include discharge permits for drilling operations, drilling bonds, spacing of wells, unitization and pooling of properties, environmental protection, reports concerning operations, and taxation.

Under these laws and regulations, we could be liable for personal injuries, property damage, oil spills, discharge of hazardous materials, reclamation costs, remediation and clean-up costs, and other environmental damages. Failure to comply with these laws and regulations also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Further, these laws and regulations could change in ways that substantially increase our costs. Any of these liabilities, penalties, suspensions, terminations or regulatory changes could make it more expensive for us to conduct our business or cause us to limit or curtail some of our operations.

We currently own, lease or expect to acquire, and have in the past owned or leased, numerous properties that have been used for the exploration and production of oil and natural gas for many years. Although we have used operating and disposal practices that were standard in the industry at the time, petroleum hydrocarbons or wastes may have been disposed or released on or under the properties owned or leased by us or on or under other locations where such wastes were taken for disposal. In addition, petroleum hydrocarbons or wastes may have been disposed or released by prior operators of properties that we are acquiring as well as by current third party operators of properties in which we have an ownership interest. Properties impacted by any such disposal or releases could be subject to costly and stringent investigatory or remedial requirements under environmental laws, some of which impose strict joint and several liability without regard to fault or the legality of the original conduct. These laws include the federal Comprehensive Environmental Response, Compensation, and Liability Act, also known as "CERCLA" or the "Superfund" law, the federal Resource Conservation and Recovery Act and analogous state laws. Under these laws and any implementing regulations, we could be required to remediate contaminated properties and take actions to compensate for damages to natural resources. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury or property damages allegedly caused by the release of petroleum hydrocarbons or wastes into the environment. We currently do not expect any remedial obligations imposed under environmental laws to have a significant effect on our operations.

Our operations in the coastal waters of Cook Inlet of Alaska are subject to the federal Oil Pollution Act, which imposes a variety of requirements related to the prevention of oil spills and liability for damages resulting from such spills in United States waters. The Oil Pollution Act imposes strict joint and several liability on responsible parties for oil removal costs and a variety of public and private damages, including natural resource damages. Liability limits for offshore facilities require a responsible party to pay all removal costs, plus up to $75 million in other damages. These liability limits do not apply, however, if the spill was caused by gross negligence or willful misconduct of the party, if the spill resulted from violation of a federal safety, construction or operation regulation, or if the party failed to report the spill or cooperate fully in any resulting cleanup. The Oil Pollution Act also requires a responsible party at an offshore facility to submit proof of its financial ability to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill. We believe our operations are in substantial compliance with Oil Pollution Act requirements.

The Department of Transportation, through the Office of Pipeline Safety and Research and Special Programs Administration, has implemented a series of rules requiring operators of natural gas and hazardous liquid pipelines to develop integrity management plans for pipelines that, in the event of a failure, could impact certain high consequence areas. These rules also require operators to conduct baseline integrity assessments of all applicable pipeline segments located in the high consequence areas. We are currently in the process of identifying all of our pipeline segments that may be subject to these rules and are developing integrity management plans for all covered pipeline segments. We do not expect to incur significant costs in achieving compliance with these rules.

Operating Hazards and Uninsured Risks. Our operations are subject to inherent hazards and risks inherent in drilling for, producing and transporting oil and natural gas, such as fire, natural disasters, explosions, blowouts, formations with abnormal pressures, failure of oilfield drilling and service tools, uncontrollable flows of underground gas, oil and formation water, pipeline ruptures or cement failures and environmental hazards such as gas leaks and oil spills. Any of these events could cause a loss of hydrocarbons, pollution or other environmental damage, clean-up responsibilities, regulatory investigations and penalties, suspension of operations, personal injury claims, loss of life, damage to our properties, or damage to the property of others. In addition, our liability for environmental hazards may include conditions created by the previous owners of properties that we purchase or lease or by acquired companies prior to the date we acquire them. As protection against operating hazards, we maintain insurance coverage against some, but not all, potential losses. We do not believe that insurance coverage for all environmental damages that could occur is available at a reasonable cost. We believe that our insurance is adequate and customary for companies of similar size and operation, but losses could occur for uninsured risks or in amounts exceeding existing coverage. The occurrence of an event that is not fully covered by insurance could adversely affect our financial condition and results of operations.

PART II

Item 7A

Quantitative *and* Qualitative Disclosures About Market Risk

We only enter derivative financial instruments in conjunction with our hedging activities. These instruments principally include commodity futures, collars, swaps and option agreements and interest rate swap agreements. These financial and commodity-based derivative contracts are used to limit the risks of fluctuations in interest rates and natural gas and crude oil prices. Gains and losses on these derivatives are generally offset by losses and gains on the respective hedged exposures.

Our Board of Directors has adopted a policy governing the use of derivative instruments, which requires that all derivatives used by us relate to an underlying, offsetting position, anticipated transaction or firm commitment, and prohibits the use of speculative, highly complex or leveraged derivatives. The policy also requires review and approval by the Chairman, the Executive Vice President - Administration and the Senior Vice President - Marketing of all risk management programs using derivatives and all derivative transactions. These programs are also reviewed at least quarterly by our internal risk management committee and annually by the Board of Directors.

Hypothetical changes in interest rates and prices chosen for the following estimated sensitivity effects are considered to be reasonably possible near-term changes generally based on consideration of past fluctuations for each risk category. It is not possible to accurately predict future changes in interest rates and product prices. Accordingly, these hypothetical changes may not necessarily be an indicator of probable future fluctuations.

Interest Rate Risk

We are exposed to interest rate risk on short-term and long-term debt carrying variable interest rates. At December 31, 2004, our variable rate debt had a carrying value of $446 million, which approximated its fair value, and our fixed rate debt had a carrying value of $1.60 billion and an approximate fair value of $1.69 billion. We attempt to balance the benefit of lower cost variable rate debt that has inherent increased risk with more expensive fixed rate debt that has less market risk. This is accomplished through a mix of bank debt with short-term variable rates and fixed rate senior and subordinated debt, as well as the occasional use of interest rate swaps.

The following table shows the carrying amount and fair value of long-term debt and the hypothetical change in fair value that would result from a 100-basis point change in interest rates. Unless otherwise noted, the hypothetical change in fair value could be a gain or a loss depending on whether interest rates increase or decrease.

(in thousands)	Carrying Amount	Fair Value (a)	Hypothetical Change in Fair Value
December 31, 2004			
Long-term debt	$(2,042,732)	$ (2,133,818)	$ 115,205
December 31, 2003			
Long-term debt	$(1,252,000)	$ (1,275,285)	$ 51,085

(a) Fair value is based upon current market quotes and is the estimated amount required to purchase our long-term debt on the open market. This estimated value does not include any redemption premium.

Commodity Price Risk

We hedge a portion of our price risks associated with our crude oil and natural gas sales. As of December 31, 2004, we had outstanding gas futures contracts, swap agreements and gas basis swap agreements. These contracts and agreements had a net fair value loss of approximately $30.8 million at December 31, 2004 and a net fair value loss of $84.7 million at December 31, 2003. Of the December 31, 2004 fair value, a $34.8 million loss has been determined based on the exchange-trade value of NYMEX contracts, and a $4 million gain has been determined based on the broker bid and ask quotes for basis contracts. These fair values approximate amounts confirmed by the counterparties. The aggregate effect of a hypothetical 10% change in gas prices would result in a change of approximately $47.9 million in the fair value of gas futures contracts and swap agreements at December 31, 2004. As of December 31, 2004, outstanding oil futures contracts and differential swaps had a net fair value loss of $22.1 million. The aggregate effect of a hypothetical 10% change in oil prices would result in a change of approximately $20.6 million in the fair value of these oil futures and differential swaps at December 31, 2004. None of our derivative contracts have margin requirements or collateral provisions that could require funding prior to the scheduled cash settlement date. See Note 8 to Consolidated Financial Statements.

Because most of our futures contracts and swap agreements have been designated as hedge derivatives, changes in their fair value generally are reported as a component of accumulated other comprehensive income (loss) until the related sale of production occurs. At that time, the realized hedge derivative gain or loss is transferred to product revenues in the consolidated income statement.

We had a physical delivery contract to sell 35,500 Mcf per day from 2002 through July 2005 at a price of approximately 10% of the average NYMEX futures price for intermediate crude oil. Because this gas sales contract was priced based on crude oil, which is not clearly and closely associated with natural gas prices, it was accounted for as a non-hedge derivative financial instrument. This contract (referred to as the Enron Btu swap contract) was terminated in December 2001 in conjunction with the bankruptcy filing of Enron Corporation. In November 2001, we entered derivative contracts to effectively defer until 2005 and 2006 any cash flow impact related to 25,000 Mcf of daily gas deliveries in 2002 that were to be made under the Enron Btu swap contract. The net fair value loss on these contracts at December 31, 2004 was $19.1 million. The effect of a hypothetical 10% change in gas prices would result in a change of approximately $5.6 million in the fair value of these contracts, while a 10% change in crude oil prices would result in a change of approximately $3.7 million. Since the contracts are not hedge derivatives, changes in their fair value are recognized in our consolidated income statement as a derivative fair value gain or loss.

PART II

Item 8

FINANCIAL STATEMENTS *and* SUPPLEMENTARY DATA

PAGE

The following financial statements and supplementary information are included under Item 15(a):

Item 9

Changes in *and* Disagreements with Accountants on Accounting *and* Financial Disclosure

There have been no changes in accountants or any disagreements with accountants on any matter of accounting principles or practices or financial statement disclosures during the two years ended December 31, 2004.

PART II

Item 9A

Controls *and* Procedures

a) Evaluation of Disclosure Controls and Procedures

We performed an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Exchange Act Rules 13a-15 and 15d-15 as of the end of the period covered by this report. Based upon that evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that our disclosure controls and procedures are effective in timely alerting them to material information relating to the Company required to be included in our periodic filings with the Securities and Exchange Commission. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within our Company have been detected.

b) Management's Report on Internal Control over Financial Reporting

Our management's report on internal control over financial reporting is set forth in Item 8 of this Annual Report on Form 10-K and is incorporated by reference herein.

c) Changes in Internal Control over Financial Reporting

There were no changes in our internal controls over financial reporting during the quarter ended December 31, 2004 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

PART II

Item 9B

Other Information

None.

Except for the portion of Item 10 relating to Executive Officers of the Registrant which is included in Part I of this Report or is included below, the information called for by Items 10 through 14 is incorporated by reference to the Company's Notice of Annual Meeting and Proxy Statement to be filed with the Securities and Exchange Commission no later than April 29, 2005.

Item 10. Directors and Executive Officers of the Registrant

We have a Code of Business Conduct and Ethics that applies to all directors, officers and employees, including the chief executive officer and senior financial officers. We also have a Code of Ethics for the Chief Executive Officer and Senior Financial Officers. You can find our Code of Business Conduct and Ethics and our Code of Ethics for the Chief Executive Officer and Senior Financial Officers on our web site at http://www.xtoenergy.com. You can also obtain a free copy of these materials by contacting us at 810 Houston Street, Fort Worth, Texas 76102, Attn: Corporate Secretary. Any amendments to or waivers from these codes that apply to our executive officers will be posted on the Company's web site or by other appropriate means in accordance with the rules of the Securities and Exchange Commission.

Item 11. Executive Compensation

Item 12. Security Ownership of Certain Beneficial Owners and Management

Item 13. Certain Relationships and Related Transactions

Item 14. Principal Accountant Fees and Services

PART IV

Item 15

EXHIBITS *and* FINANCIAL STATEMENT SCHEDULES

All other financial statement schedules have been omitted because they are not applicable or the required information is presented in the financial statements or the notes to consolidated financial statements.

(b) Exhibits

See Index to Exhibits at page 80 for a description of the exhibits filed as a part of this report. Documents filed prior to June 1, 2001, were filed with the Securities and Exchange Commission under our prior name, Cross Timbers Oil Company.

(IN THOUSANDS, EXCEPT SHARES)	DECEMBER 31 2004	2003
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 9,700	$ 6,995
Accounts receivable, net	333,134	193,666
Derivative fair value	14,713	11,351
Current income tax receivable	9,089	4,503
Deferred income tax benefit	22,613	32,455
Other	47,716	12,193
Total Current Assets	436,965	261,163
Property and Equipment, at cost – successful efforts method:		
Producing properties	6,871,245	4,253,221
Undeveloped properties	61,170	12,627
Other	106,031	70,494
Total Property and Equipment	7,038,446	4,336,342
Accumulated depreciation, depletion and amortization	(1,414,068)	(1,024,275)
Net Property and Equipment	5,624,378	3,312,067
Other Assets:		
Derivative fair value	–	646
Other	49,029	37,258
Total Other Assets	49,029	37,904
TOTAL ASSETS	$ 6,110,372	$ 3,611,134
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 415,350	$ 218,710
Payable to royalty trusts	9,823	4,848
Derivative fair value	75,534	96,653
Other	259	346
Total Current Liabilities	500,966	320,557
Long-term Debt	2,042,732	1,252,000
Other Long-term Liabilities:		
Derivative fair value	11,179	18,044
Deferred income taxes payable	756,369	426,730
Asset retirement obligation	159,948	93,379
Other	39,805	34,782
Total Other Long-term Liabilities	967,301	572,935
Commitments and Contingencies (Note 6)		
Stockholders' Equity:		
Common stock ($.01 par value, 500,000,000 shares authorized, 348,428,489 and 312,335,137 shares issued)	3,484	3,123
Additional paid-in capital	1,410,135	753,120
Treasury stock, at cost (1,250,266 and -0- shares)	(24,917)	–
Retained earnings	1,239,553	762,640
Accumulated other comprehensive income (loss)	(28,882)	(53,241)
Total Stockholders' Equity	2,599,373	1,465,642
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 6,110,372	$ 3,611,134

See accompanying notes to consolidated financial statements.

(IN THOUSANDS, EXCEPT PER SHARE DATA)	YEAR ENDED DECEMBER 31 2004	2003	2002
REVENUES			
Gas and natural gas liquids	$ 1,613,135	$ 1,040,370	$ 681,147
Oil and condensate	318,800	135,058	115,324
Gas gathering, processing and marketing	18,380	12,982	11,622
Other	(2,714)	1,145	2,070
Total Revenues	1,947,601	1,189,555	810,163
EXPENSES			
Production	245,892	164,864	129,182
Taxes, transportation and other	174,007	104,654	57,225
Exploration	10,513	1,811	2,186
Depreciation, depletion and amortization	406,749	284,006	204,109
Accretion of discount in asset retirement obligation	7,592	5,330	–
Gas gathering and processing	6,586	9,350	9,114
General and administrative	165,092	107,675	62,114
Derivative fair value (gain) loss	11,889	10,201	(2,599)
Total Expenses	1,028,320	687,891	461,331
OPERATING INCOME	919,281	501,664	348,832
OTHER INCOME (EXPENSE)			
Gain on distribution of royalty trust units	–	16,216	–
Loss on extinguishment of debt	–	(9,601)	(8,528)
Interest expense, net	(93,661)	(63,769)	(53,555)
Total Other Expense	(93,661)	(57,154)	(62,083)
INCOME BEFORE INCOME TAX AND CUMULATIVE EFFECT OF ACCOUNTING CHANGE	825,620	444,510	286,749
Income Tax Expense	317,738	158,009	100,690
NET INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	507,882	286,501	186,059
Cumulative effect of accounting change, net of tax	–	1,778	–
NET INCOME	$ 507,882	$ 288,279	$ 186,059
EARNINGS PER COMMON SHARE			
Basic:			
Net income before cumulative effect of accounting change	$ 1.53	$ 0.95	$ 0.67
Cumulative effect of accounting change, net of tax	–	0.01	–
Net income	$ 1.53	$ 0.96	$ 0.67
Diluted:			
Net income before cumulative effect of accounting change	$ 1.51	$ 0.94	$ 0.66
Cumulative effect of accounting change, net of tax	–	0.01	–
Net income	$ 1.51	$ 0.95	$ 0.66
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING	332,907	299,665	277,834

See accompanying notes to consolidated financial statements.

(IN THOUSANDS)	YEAR ENDED DECEMBER 31 2004	2003	2002
OPERATING ACTIVITIES			
Net income	$ 507,882	$ 288,279	$ 186,059
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	406,749	284,006	204,109
Accretion of discount in asset retirement obligation	7,592	5,330	–
Non-cash incentive compensation	67,184	53,123	26,990
Deferred income tax	272,672	157,715	100,368
Gain on distribution of royalty trust units	–	(16,216)	–
Non-cash derivative fair value loss	6,652	10,771	6,890
Cumulative effect of accounting change, net of tax	–	(1,778)	–
Loss on extinguishment of debt	–	9,601	8,528
Non-cash settlement gain with Enron Corporation, and related revenue	–	–	(16,142)
Other non-cash items	6,366	(386)	(3,084)
Changes in operating assets and liabilities (a)	(58,205)	3,736	(22,876)
Cash Provided by Operating Activities	1,216,892	794,181	490,842
INVESTING ACTIVITIES			
Proceeds from sale of property and equipment	25,265	–	149
Property acquisitions	(1,905,109)	(653,742)	(358,087)
Development and capitalized exploration costs	(599,458)	(459,762)	(370,558)
Other property and asset additions	(38,959)	(21,730)	(8,321)
Cash Used by Investing Activities	(2,518,261)	(1,135,234)	(736,817)
FINANCING ACTIVITIES			
Proceeds from long-term debt	3,883,423	1,835,000	1,156,000
Payments on long-term debt	(3,093,000)	(1,701,170)	(893,830)
Net proceeds from common stock offering	580,272	247,972	–
Dividends	(19,824)	(6,640)	(4,984)
Senior note offering and debt costs	(13,869)	(7,797)	(8,381)
Proceeds from exercise of stock options and warrants	7,973	16,248	23,745
Payments upon exercise of stock options	(13,030)	(18,183)	(1,440)
Subordinated note redemption costs	–	(7,139)	(3,794)
Purchases of treasury stock and other	(27,871)	(25,197)	(13,197)
Cash Provided by Financing Activities	1,304,074	333,094	254,119
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	2,705	(7,959)	8,144
Cash and Cash Equivalents, January 1	6,995	14,954	6,810
Cash and Cash Equivalents, December 31	$ 9,700	$ 6,995	$ 14,954
(a) Changes in Operating Assets and Liabilities			
Accounts receivable	$ (131,817)	$ (49,628)	$ (19,088)
Other current assets	(39,791)	(5,523)	2,758
Other operating assets	4,153	1,103	4,293
Enron Btu swap contract	–	–	(43,272)
Current liabilities	109,250	57,784	32,433
	$ (58,205)	$ 3,736	$ (22,876)

See accompanying notes to consolidated financial statements.

XTO Energy Inc. Consolidated Statements of Stockholders' Equity

(in thousands, except per share amounts)	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balances, December 31, 2001	$ 2,933	$ 483,481	$(64,714)	$ 328,712	$ 70,638	$ 821,050
Net income	–	–	–	186,059	–	186,059
Change in hedge derivative fair value, net of applicable income tax of $51,543	–	–	–	–	(95,723)	(95,723)
Hedge derivative contract settlements reclassified into earnings from accumulated other comprehensive income, net of applicable income tax of $19,647	–	–	–	–	(36,488)	(36,488)
Comprehensive income						53,848
Issuance/vesting of performance shares	22	25,596	(10,276)	–	–	15,342
Stock option and warrant exercises, including income tax benefits	61	24,071	(35)	–	–	24,097
Treasury stock purchases	–	–	(1,536)	–	–	(1,536)
Common stock dividends ($0.018 per share)	–	–	–	(5,015)	–	(5,015)
Balances, December 31, 2002	3,016	533,148	(76,561)	509,756	(61,573)	907,786
Net income	–	–	–	288,279	–	288,279
Change in hedge derivative fair value, net of applicable income tax of $65,850	–	–	–	–	(122,293)	(122,293)
Hedge derivative contract settlements reclassified into earnings from accumulated other comprehensive income, net of applicable income tax of $70,337	–	–	–	–	130,625	130,625
Comprehensive income						296,611
Issuance/vesting and forfeiture of performance shares	45	51,080	(23,124)	–	–	28,001
Stock option exercises, including income tax benefits	44	22,919	–	–	–	22,963
Treasury stock purchases	–	–	(2,296)	–	–	(2,296)
Common stock offering	230	247,742	–	–	–	247,972
Fair value of royalty trust unit distribution	–	–	–	(28,151)	–	(28,151)
Common stock dividends ($0.024 per share)	–	–	–	(7,244)	–	(7,244)
Cancellation of treasury stock	(212)	(101,769)	101,981	–	–	–
Balances, December 31, 2003	3,123	753,120	–	762,640	(53,241)	1,465,642
Net income	–	–	–	507,882	–	507,882
Change in hedge derivative fair value, net of applicable income tax of $51,063	–	–	–	–	(85,023)	(85,023)
Hedge derivative contract settlements reclassified into earnings from accumulated other comprehensive income, net of applicable income tax of $63,485	–	–	–	–	109,382	109,382
Comprehensive income						532,241
Issuance/vesting of performance shares	25	64,358	(24,105)	–	–	40,278
Stock option exercises, including income tax benefits	19	12,702	–	–	–	12,721
Treasury stock purchases	–	–	(812)	–	–	(812)
Common stock offering	317	579,955	–	–	–	580,272
Common stock dividends ($0.09 per share)	–	–	–	(30,969)	–	(30,969)
Balances, December 31, 2004	$ 3,484	$1,410,135	$(24,917)	$ 1,239,553	$ (28,882)	$ 2,599,373

See accompanying notes to consolidated financial statements.

1. Organization and Summary of Significant Accounting Policies

XTO Energy Inc., a Delaware corporation, was organized under the name Cross Timbers Oil Company in October 1990 to ultimately acquire the business and properties of predecessor entities that were created from 1986 through 1989. Cross Timbers Oil Company completed its initial public offering of common stock in May 1993 and changed its name to XTO Energy Inc. in June 2001.

The accompanying consolidated financial statements include the financial statements of XTO Energy Inc. and all of its wholly owned subsidiaries. All significant intercompany balances and transactions have been eliminated in the consolidation. In preparing the accompanying financial statements, management has made certain estimates and assumptions that affect reported amounts in the financial statements and disclosures of contingencies. Actual results may differ from those estimates. Certain amounts presented in prior period financial statements have been reclassified for consistency with current period presentation.

All common stock shares and per share amounts in the accompanying financial statements have been adjusted for the four-for-three stock split to be effected on March 15, 2005, the five-for-four stock split effected March 17, 2004 and the four-for-three stock split effected on March 18, 2003.

We are an independent oil and gas company with production and exploration concentrated in Texas, Oklahoma, Arkansas, Kansas, New Mexico, Colorado, Wyoming, Alaska, Utah and Louisiana. We also gather, process and market gas, transport and market oil and conduct other activities directly related to our oil and gas producing activities.

Property and Equipment

We follow the successful efforts method of accounting, capitalizing costs of successful exploratory wells and expensing costs of unsuccessful exploratory wells. Exploratory geological and geophysical costs are expensed as incurred. All developmental costs are capitalized. We generally pursue acquisition and development of proved reserves as opposed to exploration activities. A significant portion of the property costs reflected in the accompanying consolidated balance sheets are from acquisitions of producing properties from other oil and gas companies. Producing properties balances include costs of $139.4 million at December 31, 2004 and $80.6 million at December 31, 2003 related to wells in process of drilling. Drill well costs are transferred to producing properties generally within one month of the well completion date. See Note 15 for information regarding exploratory well costs. Inventory held for future use on our producing properties totaled $34.7 million at December 31, 2004 and $6.5 million at December 31, 2003, and is included in other current assets on the consolidated balance sheet.

Depreciation, depletion and amortization of producing properties is computed on the unit-of-production method based on estimated proved oil and gas reserves. Other property and equipment is generally depreciated using the straight-line method over estimated useful lives which range from 3 to 40 years. Repairs and maintenance are expensed, while renewals and betterments are generally capitalized.

If conditions indicate that long-term assets may be impaired, the carrying value of property is compared to management's future estimated pre-tax cash flow from properties generally aggregated on a field-level basis. If impairment is necessary, the asset carrying value is written down to fair value. Cash flow pricing estimates are based on existing proved reserve and production information and pricing assumptions that management believes are reasonable. Impairment of individually significant undeveloped properties is assessed on a property-by-property basis, and impairment of other undeveloped properties is assessed and amortized on an aggregate basis.

Asset Retirement Obligation

Effective January 1, 2003, we adopted Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*. SFAS No. 143 provides that, if the fair value for asset retirement obligation can be reasonably estimated, the liability should be recognized in the period when it is incurred. Oil and gas producing companies incur this liability upon acquiring or drilling a well. Under the method prescribed by SFAS No. 143, the retirement obligation is recorded as a liability at its estimated present value at the asset's inception, with an offsetting increase to producing properties on the balance sheet. Periodic accretion of discount of the estimated liability is recorded as an expense in the income statement. Prior to adoption of SFAS No. 143, we accrued for any estimated asset retirement obligation, net of estimated salvage value, as part of our calculation of depletion, depreciation and amortization. This method resulted in recognition of the obligation over the life of the property on a unit-of-production basis, with the estimated obligation netted in property cost as part of the accumulated depreciation, depletion and amortization balance. See Note 5.

Royalty Trusts

We created Cross Timbers Royalty Trust in February 1991 and Hugoton Royalty Trust in December 1998 by conveying defined net profits interests in certain of our properties. Units of both trusts are traded on the New York Stock Exchange. We make monthly net profits payments to each trust based on revenues and costs from the related underlying properties. We own 54.3% of Hugoton Royalty Trust, which is the portion we retained following our sale of units in 1999 and 2000. The cost of our interest in Hugoton Royalty Trust is included in producing properties. We owned 22.7% of Cross Timbers Royalty Trust as a result of units we purchased on the open market from 1996 through 1998. In August 2003, our Board of Directors declared a dividend of 0.0044 units of Cross Timbers Royalty Trust for each share of our common stock outstanding on September 2, 2003. Our Cross Timbers Royalty Trust units were distributed to our common stockholders on September 18, 2003, after which we no longer own any Cross Timbers Royalty Trust units. We recorded this dividend at $28.2 million, the fair market value of the units on the date of distribution, resulting in a gain on distribution of $16.2 million. Amounts due the trusts, net of amounts retained by our ownership of trust units, are deducted from our revenues, taxes, production expenses and development costs.

Cash and Cash Equivalents

Cash equivalents are considered to be all highly liquid investments having an original maturity of three months or less.

Income Taxes

We record deferred income tax assets and liabilities to recognize timing differences between recognition of income for financial statement and income tax reporting purposes. Deferred income tax assets are calculated using enacted tax rates applicable to taxable income in the years when we anticipate these timing differences will reverse. The effect of changes in tax rates is recognized in the period of enactment. See *New Accounting Pronouncements* below.

Other Assets

Other assets primarily include deferred debt costs that are amortized to interest expense over the term of the related debt (Note 3) and the long-term portion of gas balancing receivable (see *Revenue Recognition and Gas Balancing* below). We do not have any goodwill or significant intangible assets that are subject to potential impairment assessment. Other assets are presented net of accumulated amortization of $13.3 million at December 31, 2004 and $19. 8 million at December 31, 2003.

Derivatives

We use derivatives to hedge against changes in cash flows related to product price and interest rate risks, as opposed to their use for trading purposes. SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, requires that all derivatives be recorded on the balance sheet at fair value. We generally determine the fair value of futures contracts and swap contracts based on the difference between the derivative's fixed contract price and the underlying market price at the determination date. The fair value of call options and collars are generally determined under the Black-Scholes option-pricing model. Most values are confirmed by counterparties to the derivative.

Realized and unrealized gains and losses on derivatives that are not designated as hedges, as well as on the ineffective portion of hedge derivatives, are recorded as a derivative fair value gain or loss in the income statement. Unrealized gains and losses on effective cash flow hedge derivatives, as well as any deferred gain or loss realized upon early termination of effective hedge derivatives, are recorded as a component of accumulated other comprehensive income (loss). When the hedged transaction occurs, the realized gain or loss, as well as any deferred gain or loss, on the hedge derivative is transferred from accumulated other comprehensive income (loss) to earnings. Realized gains and losses on commodity hedge derivatives are recognized in oil and gas revenues, and realized gains and losses on interest hedge derivatives are recorded as adjustments to interest expense. Settlements of derivatives are included in cash flows from operating activities.

To summarize, we record our derivatives at fair value in our consolidated balance sheets. Gains and losses resulting from changes in fair value and upon settlement are recorded as follows:

Derivative Type	Fair Value Gains / Losses	Financial Statement Classification
Non-hedge derivatives and Hedge derivatives – ineffective portion	Unrealized and Realized	Derivative fair value (gain) loss in the Consolidated Income Statements
Hedge derivatives – effective portion	Unrealized	Accumulated other comprehensive income in Stockholders' Equity in the Consolidated Balance Sheets
	Realized	Hedged item as classified in the Consolidated Income Statements (e.g., gas revenue, oil revenue or interest expense)

To designate a derivative as a cash flow hedge, we document at the hedge's inception our assessment that the derivative will be highly effective in offsetting expected changes in cash flows from the item hedged. This assessment, which is updated at least quarterly, is generally based on the most recent relevant historical correlation between the derivative and the item hedged. The ineffective portion of the hedge is calculated as the difference between the change in fair value of the derivative and the estimated change in cash flows from the item hedged. If, during the derivative's term, we determine the hedge is no longer highly effective, hedge accounting is prospectively discontinued and any remaining unrealized gains or losses on the effective portion of the derivative are reclassified to earnings as oil or gas revenue or interest expense when the underlying transaction occurs. If it is determined that the designated hedge transaction is not likely to occur, any unrealized gains or losses are recognized immediately in the income statement as a derivative fair value gain or loss.

In conjunction with our hedging activities, we occasionally sell natural gas call options. Because sold options do not provide protection against declining prices, they do not qualify for hedge or loss deferral accounting. The opportunity loss, related to gas prices exceeding the fixed gas prices effectively provided by selling the call options, is recognized as a derivative fair value loss, rather than deferring the loss and recognizing it as reduced gas revenue when the hedged production occurs, as prescribed by hedge accounting.

Physical delivery contracts that are not expected to be net cash settled are deemed to be normal sales and therefore are not accounted for as derivatives. However, physical delivery contracts that have a price not clearly and closely associated with the asset sold are not a normal sale and must be accounted for as a non-hedge derivative (Note 8).

Revenue Recognition and Gas Balancing

Oil, gas and natural gas liquids revenues are recognized when the products are sold and delivery to the purchaser has occurred. At times we may sell more or less than our entitled share of gas production. When this happens, we use the entitlement method of accounting for gas sales, based on our net revenue interest in production. Accordingly, revenue is deferred for gas deliveries in excess of our net revenue interest, while revenue is accrued for the undelivered volumes. Production imbalances are generally recorded at the estimated sales price in effect at the time of production. The consolidated balance sheets include the following amounts related to production imbalances:

	December 31			
	2004		2003	
(in thousands)	Amount	Mcf	Amount	Mcf
Accounts receivable - current underproduction	$ 30,780	8,116	$ 23,949	7,135
Accounts payable - current overproduction	(24,087)	(6,388)	(19,366)	(5,900)
Net current gas underproduction balancing receivable	$ 6,693	1,728	$ 4,583	1,235
Other assets - noncurrent underproduction	$ 17,723	4,868	$ 19,385	6,148
Other long-term liabilities - noncurrent overproduction	(33,262)	(9,063)	(29,776)	(9,353)
Net long-term gas overproduction balancing payable	(15,539)	(4,195)	(10,391)	(3,205)
Other assets - noncurrent carbon dioxide underproduction	1,985	12,480	1,977	12,354
Net long-term overproduction balancing payable	$ (13,554)		$ (8,414)	

Gas Gathering, Processing and Marketing Revenues

We market our gas, as well as some gas produced by third parties, to brokers, local distribution companies and end-users. Gas gathering and marketing revenues are recognized in the month of delivery based on customer nominations. Gas processing and marketing revenues are recorded net of cost of gas sold of $98.3 million for 2004, $66.3 million for 2003 and $55.6 million for 2002. These amounts are net of intercompany eliminations.

Other Revenues

Other revenues result from and are related to our ongoing major operations. These revenues include various gains and losses, including from lawsuits and other disputes, as well as from other than significant sales of property and equipment.

Loss Contingencies

We account for loss contingencies in accordance with SFAS No. 5, *Accounting for Contingencies*. Accordingly, when management determines that it is probable that an asset has been impaired or a liability has been incurred, we accrue our best estimate of the loss if it can be reasonably estimated. Our legal costs related to litigation are expensed as incurred. See Note 6.

Interest

Interest expense includes amortization of deferred debt costs and is presented net of interest income of $402,000 in 2004, $553,000 in 2003 and $836,000 in 2002, and net of capitalized interest of $2.6 million in 2004, $2.2 million in 2003 and $4.3 million in 2002. Interest is capitalized as producing property cost based on the weighted average interest rate and the cost of wells in process of drilling. Included in accounts payable and accrued liabilities is accrued interest of $26.6 million at December 31, 2004 and $11.5 million at December 31, 2003.

Stock-Based Compensation

In accordance with Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees*, no compensation is recorded for stock options or other stock-based awards that are granted to employees or non-employee directors with an exercise price equal to or above the common stock price on the grant date. Compensation related to performance share grants with time vesting conditions is based on the fair value of the award at the grant date and recognized over the vesting period. Compensation related to performance shares with price target vesting is recognized over the estimated vesting period if management believes it is able to reasonably estimate a vesting date or, if earlier, when the price target is reached. See *New Accounting Pronouncements* below and Note 12.

As required to be disclosed pursuant to SFAS No. 148, *Accounting for Stock-Based Compensation—Transition and Disclosure*, the following is the pro forma effect of recording stock-based compensation at the estimated fair value of awards on the grant date, as prescribed by SFAS No. 123, *Accounting for Stock-Based Compensation*:

	Year Ended December 31		
(in thousands, except per share data)	2004	2003	2002
Net income as reported	$ 507,882	$ 288,279	$ 186,059
Add stock-based compensation expense included in the income statement, net of related tax effects	56,368	34,530	17,543
Deduct stock-based employee compensation expense determined under fair value method for all awards, net of related tax effects	(76,859)	(33,498)	(19,762)
Pro forma net income	$ 487,391	$ 289,311	$ 183,840
Earnings per common share:			
Basic - as reported	$ 1.53	$ 0.96	$ 0.67
Basic - pro forma	$ 1.46	$ 0.96	$ 0.66
Diluted - as reported	$ 1.51	$ 0.95	$ 0.66
Diluted - pro forma	$ 1.45	$ 0.95	$ 0.65

Earnings per Common Share

In accordance with SFAS No. 128, *Earnings Per Share*, we report basic earnings per common share, which excludes the effect of potentially dilutive securities, and diluted earnings per common share, which includes the effect of all potentially dilutive securities unless their impact is antidilutive. See Note 10.

Segment Reporting

In accordance with SFAS No. 131, *Disclosures about Segments of an Enterprise and Related Information*, we evaluated how the Company is organized and managed, and have identified only one operating segment, which is the exploration and production of oil, natural gas and natural gas liquids. We consider our gathering, processing and marketing functions as ancillary to our oil and gas producing activities. All of our assets are located in the United States, and all revenues are attributable to United States customers.

Our production is sold to various purchasers, based on their credit rating and location of our production. For the year ended December 31, 2004, sales to each of two purchasers were approximately 20% and 13% of total revenues. For the year ended December 31, 2003, sales to each of three purchasers were approximately 25%, 15% and 12% of total revenues. For the year ended December 31, 2002, sales to each of two purchasers were approximately 10% of total revenues. We believe that alternative purchasers are available, if necessary, to purchase production at prices substantially similar to those received from these significant purchasers. We currently have greater concentrations of credit with several A- or better rated integrated energy companies.

New Accounting Pronouncements

In December 2004, the Financial Accounting Standards Board issued SFAS No. 153, *Exchanges of Nonmonetary Assets, an Amendment of APB Opinion No. 29*, which provides that all nonmonetary asset exchanges that have commercial substance must be measured based on the fair value of the assets exchanged, and any resulting gain or loss recorded. An exchange is defined as having commercial substance if it results in a significant change in expected future cash flows. Exchanges of operating interests by oil and gas producing companies to form a joint venture continue to be exempted. APB Opinion 29 previously exempted all exchanges of similar productive assets from fair value accounting, therefore resulting in no gain or loss recorded for such exchanges. We must implement SFAS 153 for any nonmonetary asset exchanges occurring on or after January 1, 2006. This change in accounting is currently not expected to have a significant effect on our reported financial position or earnings.

In December 2004, the FASB issued Staff Position FAS 109-1 that concluded that the special tax deduction allowed under the American Jobs Creation Act of 2004 should be accounted for as a "special deduction" instead of a tax rate reduction as provided by SFAS 109. Accordingly, any tax relief the Company receives under the new tax law will be recorded as a reduction of current tax when realized, rather than an immediate reduction to its accrued deferred income tax liability.

Also in December 2004, the FASB issued SFAS No. 123 (Revised 2004), *Share-Based Payment*, which requires that compensation related to all stock-based awards, including stock options, be recognized in the financial statements. This pronouncement replaces SFAS No. 123, *Accounting for Stock-Based Compensation*, and supersedes APB Opinion No. 25, *Accounting for Stock Issued to Employees*, and will be effective beginning July 1, 2005. We have previously recorded stock compensation pursuant to the intrinsic value method under APB No. 25, whereby no compensation was recognized for most stock option awards. We expect that stock option grants will continue to be a significant part of employee compensation, and, therefore, SFAS No. 123R will have a significant impact on our financial statements. For the pro forma effect of recording compensation for all stock awards at fair value, utilizing the Black-Scholes method, see *Stock-Based Compensation* above. We are currently considering alternative valuation methods to determine stock award fair value for grants after June 30, 2005. We plan to use the modified prospective application method of adopting SFAS No. 123R, whereby the estimated fair value of unvested stock awards granted prior to July 1, 2005 will be recognized as compensation expense in periods subsequent to June 30, 2005, based on the estimated service period. The fair value of awards granted prior to July 1, 2005 will be the same value as determined under the Black–Scholes method for our pro forma disclosure under *Stock-Based Compensation* above. As of February 22, 2005, all stock options outstanding at that date vested when the common stock price closed above the target price level of $31.88, resulting in no compensation expense to be recognized after June 30, 2005 related to these awards.

2. Related Party Transactions

A firm, partially owned by one of our directors, has performed property acquisition advisory services for the Company. We paid this firm total fees of $8.8 million in 2004 and $2.4 million in 2002, and there were no amounts payable at December 31, 2004 or 2003. No fees were paid to this firm in 2003. This same director-related company represented the seller of properties for acquisitions totaling approximately $186 million that we closed in January 2004. In February 2005, this firm was acquired by another company with which we expect to continue to have a relationship.

A portion of the producing properties obtained in the ChevronTexaco acquisition (Note 13) were considered nonstrategic and marked for disposition at the time of purchase. In August 2004, we exchanged $37.8 million of these properties for 19,000 net contiguous acres in our new core operating area, the Barnett Shale of North Texas, and $25.4 million in other consideration. This exchange was with companies either wholly or majority owned by the adult children and a brother of Bob R. Simpson, Chairman and Chief Executive Officer of the Company. In connection with this exchange, we granted these companies an option to purchase other properties included in the ChevronTexaco acquisition. On March 1, 2005, these companies purchased the properties for an adjusted purchase price of $11.5 million. Lehman Brothers Inc. provided a fairness opinion to the Board of Directors on the value of properties exchanged and sold.

3. Debt

Our long-term debt consists of the following:

(IN THOUSANDS)	DECEMBER 31 2004	DECEMBER 31 2003
BANK DEBT:		
Revolving credit agreement due February 2009, 3.49% at December 31, 2004	$ 146,000	$ 502,000
Term loan due April 2010, 3.17% at December 31, 2004	300,000	–
SENIOR NOTES:		
$7\frac{1}{2}$%, due April 15, 2012	350,000	350,000
$6\frac{1}{4}$%, due April 15, 2013	400,000	400,000
4.9%, due February 1, 2014, net of discount	497,012	–
5%, due January 31, 2015, net of discount	349,720	–
Total long-term debt	$ 2,042,732	$ 1,252,000

Other than borrowings under our revolving credit agreement, no debt matures within five years. Before the February 2009 maturity, we may renegotiate the revolving credit agreement to increase the borrowing commitment and extend the maturity.

Bank Debt

In February 2004, we fully repaid our revolving facility and entered a new five-year revolving credit agreement with commercial banks that matures in February 2009. The agreement currently provides for a maximum commitment amount of $1 billion, and an interest rate based on London Interbank Offered Rates ("LIBOR") plus 1%. The loan agreement provides the option of borrowing at floating interest rates based on the prime rate, certificate of deposit rates, or LIBOR. Interest is paid at maturity, or quarterly if the term is for a period of 90 days or more. We also incur a commitment fee on unused borrowing commitments, which was 0.20% at February 2005. The agreement requires us to maintain a ratio of debt-to-total capitalization of not more than 60%. Borrowings under the loan agreement may be prepaid at any time without penalty. The weighted average interest rate on bank debt was 2.6% during 2004 and 2003 and 3.2% during 2002.

In November 2004, we entered a $300 million five-year term loan due April 2010 with an initial interest rate of LIBOR plus 0.75%. Other terms and conditions are substantially the same as our revolving credit agreement.

Senior Notes

In April 2002, we sold $350 million of $7\frac{1}{2}$% senior notes due in April 2012, with interest payable each April 15 and October 15. Net proceeds of $341.6 million were used to finance property transactions (Note 13), to redeem our $9\frac{1}{4}$% senior subordinated notes and to reduce bank debt.

In April 2003, we sold $400 million of $6\frac{1}{4}$% senior notes due in April 2013, with interest payable each April 15 and October 15. Net proceeds of $393.4 million, combined with proceeds from the concurrent sale of common stock (Note 9), were used to finance our producing property acquisition from units of Williams of Tulsa, Oklahoma (Note 13), to redeem our $8\frac{3}{4}$% senior subordinated notes and to reduce bank debt.

In January 2004, we sold $500 million of 4.9% senior notes that were issued at 99.34% of par to yield 4.98% to maturity. The notes mature on February 1, 2014 and interest is payable each February 1 and August 1. Net proceeds of $490 million were used to fund our January 2004 property acquisitions of $243 million (Note 13) and to reduce bank debt.

In September 2004, we sold $350 million of 5% notes that were issued at 99.918% of par to yield 5.011% to maturity pursuant to Rule 144A under the Securities Act of 1933, which allows unregistered transactions with qualified institutional buyers. Through March 14, 2005, noteholders can exchange these notes with notes that were registered with the Securities and Exchange Commission in February 2005. The notes are due in January 2015 and interest is payable each January 31 and July 31. Net proceeds of $347 million were used to reduce bank debt associated with our 2004 acquisitions.

The senior notes require no sinking fund. We may redeem all or a part of the senior notes at any time at a price of 100% of their principal balance plus accrued interest and a make-whole premium payment. The make-whole premium is calculated as any excess over the principal balance of the present value of remaining principal and interest payments at the U.S. Treasury rate for a comparable maturity plus no more than 0.15%.

Subordinated Debt

In April 1997, we sold $125 million of 9¼% senior subordinated notes due April 2007, and in October 1997, we sold $175 million of 8¾% senior subordinated notes due November 2009. Under the terms of an agreement with a bank counterparty, we purchased and canceled $9.7 million of 9¼% senior subordinated notes in April 2002, and we purchased and canceled $11.8 million of 8¾% senior subordinated notes in November 2002. In June 2002, we redeemed the remaining $115.3 million 9¼% notes at a redemption price of 104.625%, or $120.6 million, plus accrued interest of $1.8 million. In May 2003, we redeemed the remaining $163.2 million of our 8¾% senior subordinated notes at a redemption price of 104.375%, or $170.3 million, plus accrued interest of approximately $700,000. As a result of these transactions, we recorded a loss on extinguishment of debt of $8.5 million in 2002 and $9.6 million in 2003.

4. Income Tax

The following reconciles our income tax expense to the amount calculated at the statutory federal income tax rate:

(IN THOUSANDS)	2004	2003	2002
Income tax expense at the federal statutory rate (35%)	$ 288,967	$ 155,579	$ 100,362
State and local income taxes and other	28,771	2,430	328
Income tax expense	$ 317,738	$ 158,009	$ 100,690

Components of income tax expense are as follows:

(IN THOUSANDS)	2004	2003	2002
Current income tax	$ 45,066	$ 294	$ 322
Deferred income tax	184,927	148,304	121,396
Net operating loss carryforwards (added) used	87,745	9,411	(21,028)
Income tax expense	$ 317,738	$ 158,009	$ 100,690

Deferred tax assets and liabilities are the result of temporary differences between the financial statement carrying values and tax bases of assets and liabilities. Our net deferred tax assets and liabilities are recorded as a current asset of $22.6 million and a long-term liability of $756.4 million at December 31, 2004 and as a current asset of $32.5 million and a long-term liability of $426.7 million at December 31, 2003. Significant components of net deferred tax assets and liabilities are:

	December 31	
(IN THOUSANDS)	2004	2003
Deferred tax assets:		
Net operating loss carryforwards	$ –	$ 84,001
Alternative minimum tax credit carryforwards	37,762	429
Derivative fair value loss	31,217	40,144
Other	11,427	6,304
Total deferred tax assets	80,406	130,878
Deferred tax liabilities:		
Property and equipment	801,610	509,877
Derivative fair value gain	5,297	4,199
Other	7,255	11,077
Total deferred tax liabilities	814,162	525,153
Net deferred tax liabilities	$ (733,756)	$ (394,275)

We have estimated that all our net operating loss carryforwards will be fully utilized as of December 31, 2004. While our alternative minimum tax credit carryforwards do not have an expiration date, we expect to fully utilize them in 2005.

5. Asset Retirement Obligation

Effective January 1, 2003, we adopted SFAS No. 143, *Accounting for Asset Retirement Obligations*, recording a cumulative effect of accounting change gain, net of tax, of $1.8 million. Our asset retirement obligation primarily represents the estimated present value of the amount we will incur to plug, abandon and remediate our producing properties (including removal of our offshore platforms in Alaska) at the end of their productive lives, in accordance with applicable state laws. We determine our asset retirement obligation by calculating the present value of estimated cash flows related to the liability. The following is a summary of the asset retirement obligation activity for the years ended December 31, 2004 and 2003:

(IN THOUSANDS)	2004	2003
Asset retirement obligation, January 1	$ 93,379	$ 75,256
Revisions in the estimated cash flows	5,978	–
Liability incurred upon acquiring and drilling wells	53,886	13,879
Liability settled upon plugging and abandoning wells	(887)	(1,086)
Accretion of discount expense	7,592	5,330
Asset retirement obligation, December 31	$ 159,948	$ 93,379

Based on the same assumptions used in the calculation of our asset retirement obligation at January 1, 2003, we estimate that this obligation would have been $62.2 million at January 1, 2002 if we had adopted SFAS No. 143 as of that date. The estimated pro forma effect of earlier adoption on 2002 net income and earnings per share is not material.

6. Commitments and Contingencies

Leases

We lease compressors, offices, vehicles, aircraft and certain other equipment in our primary locations under noncancelable operating leases. Commitments related to these lease payments are not recorded in the accompanying consolidated balance sheets. As of December 31, 2004, minimum future lease payments for all noncancelable lease agreements (including the sale and operating leaseback agreements described below) were as follows:

(IN THOUSANDS)	
2005	$ 30,200
2006	23,882
2007	22,806
2008	18,605
2009	15,964
Remaining	39,666
Total	$ 151,123

Amounts incurred under operating leases (including renewable monthly leases) were $34.6 million in 2004, $31.7 million in 2003 and $26.6 million in 2002.

In March 1996, we sold our Tyrone gas processing plant and related gathering system for $28 million and entered an agreement to lease the facility from the buyers for an initial term of eight years at annual rentals of $4 million with fixed renewal options for an additional 13 years at a total cost of $7.8 million. This transaction was recorded as a sale and operating leaseback, with no gain or loss on the sale. In March 2004, we extended the lease until March 2006.

In November 1996, we sold a gathering system in Major County, Oklahoma for $8 million and entered an agreement to lease the facility from the buyers for an initial term of eight years, with fixed renewal options for an additional ten years. This transaction was recorded as a sale and operating leaseback, with a deferred gain of $3.4 million on the sale. The deferred gain is amortized over the lease term based on pro rata rentals and is recorded in other long-term liabilities in the accompanying consolidated balance sheets. The deferred gain balance at December 31, 2004 was $600,000. In November 2004, we extended the lease until November 2006.

Under each of the above sale and leaseback transactions, we do not have the right or option to purchase, nor does the lessor have the obligation to sell, the facility at any time. However, if the lessor decides to sell the facility at the end of the initial term or any renewal period, the lessor must first offer to sell it to us at its fair market value. Additionally, we have the right of first refusal of any third party offers to buy the facility after the initial term.

Transportation Contracts

We have entered firm transportation contracts with various pipelines. Under these contracts we are obligated to transport minimum daily gas volumes or pay for any deficiencies at a specified reservation fee rate. As calculated on a monthly basis, our failure to deliver these minimum volumes to the pipeline requires us to pay the pipeline for any deficiency. Our production committed to these pipelines is expected to exceed the minimum daily volumes provided in the contracts. We have generally delivered at least minimum volumes under our firm transportation contracts, therefore avoiding payment for deficiencies. As of December 31, 2004, maximum commitments under our transportation contracts were as follows:

(IN THOUSANDS)	
2005	$ 21,935
2006	22,463
2007	19,741
2008	18,804
2009	18,030
Remaining	36,368
Total	$ 137,341

Guarantees

Under the terms of some of our operating leases for compressors, airplanes and vehicles, we have various residual value guarantees and other payment provisions upon our election to return the equipment under certain specified conditions. As of December 31, 2004, we estimate the total contingent payable under these guarantees does not exceed $5 million. Guarantees related to leases entered during 2004 and 2003 were not material.

Employment Agreements

Two executive officers have year-to-year employment agreements with us. The agreements are automatically renewed each year-end unless terminated by either party upon thirty days notice prior to each December 31. Under these agreements, the officers receive a minimum annual salary of $625,000 and $450,000, respectively, and are entitled to participate in any incentive compensation programs administered by the Board of Directors. The agreements also provide that, in the event the officer terminates his employment for good reason, as defined in the agreement, we terminate the employee without cause or a change in control of the Company occurs, the officer is entitled to a lump-sum payment of three times the officer's most recent annual compensation, including any special bonuses or other compensation required to be designated as a bonus under the rules and regulations of the Securities and Exchange Commission. In addition, the officer is entitled to receive a payment sufficient to make the officer whole for any excise tax on excess parachute payments imposed by the Internal Revenue Code.

Commodity Commitments

We have entered into futures contracts, collars and swap agreements that effectively fix gas and oil prices. See Note 8.

Drilling Contracts

As of December 31, 2004, we have contracts to use 32 drilling rigs in 2005 with total commitments of $99.1 million. Early termination of these contracts at December 31, 2004 would have required us to pay maximum penalties of $34.7 million.

Litigation

On October 17, 1997, an action, styled *United States of America ex rel. Grynberg v. Cross Timbers Oil Company, et al.*, was filed in the U.S. District Court for the Western District of Oklahoma by Jack J. Grynberg on behalf of the United States under the *qui tam* provisions of the U.S. False Claims Act against the Company and certain of our subsidiaries. The plaintiff alleges that we underpaid royalties on natural gas produced from federal leases and lands owned by Native Americans in amounts in excess of 20% as a result of mismeasuring the volume of natural gas, incorrectly analyzing its heating content and improperly valuing the natural gas during at least the past ten years. The plaintiff seeks treble damages for the unpaid royalties (with interest, attorney fees and expenses), civil penalties between $5,000 and $10,000 for each violation of the U.S. False Claims Act, and an order for us to cease the allegedly improper measuring practices. This lawsuit against us and similar lawsuits filed by Grynberg against more than 300 other companies have been consolidated in the United States District Court for Wyoming. In October 2002, the court granted a motion to dismiss Grynberg's royalty valuation claims, and Grynberg's appeal of this decision was dismissed for lack of appellate jurisdiction in May 2003. The parties have completed discovery regarding whether the plaintiff has met the jurisdictional prerequisites for maintaining an action under the U.S. False Claims Act. In June 2004, we joined with other defendants in filing a motion to dismiss, contending that the plaintiff has not satisfied the jurisdictional requirements to maintain this action. A hearing on this motion has been scheduled for March 2005. While we are unable to predict the outcome of this case, we believe that the allegations of this lawsuit are without merit and intend to vigorously defend the action. Any potential liability from this claim cannot currently be reasonably estimated, and no provision has been accrued in our financial statements.

In June 2001, we were served with a lawsuit styled *Price, et al. v. Gas Pipelines, et al.* (formerly *Quinque* case). The action was filed in the District Court of Stevens County, Kansas, against us and one of our subsidiaries, along with over 200 natural gas transmission companies, producers, gatherers and processors of natural gas. The plaintiffs seek to represent a class of plaintiffs consisting of all similarly situated gas working interest owners, overriding royalty owners and royalty owners either from whom the defendants had purchased natural gas or who received economic benefit from the sale of such gas since January 1, 1974. The allegations in the case are similar to those in the *Grynberg* case; however, the *Price* case broadens the claims to cover all oil and gas leases (other than the federal and Native American leases that are the subject of the *Grynberg* case). The complaint alleges that the defendants have mismeasured both the volume and heating content of natural gas delivered into their pipelines, resulting in underpayments to the plaintiffs. The plaintiffs assert a breach of contract claim, negligent or intentional misrepresentation, civil conspiracy, common carrier liability, conversion, violation of a variety of Kansas statutes and other common law causes of action. The amount of damages was not specified in the complaint. In February 2002, we, along with one of our subsidiaries, were dismissed from the suit and another subsidiary of the Company was added. A hearing was held in January 2003, and the court held that a class should not be certified. The plaintiffs' counsel has filed an amended class action petition, which reduces the proposed class to only royalty owners, reduces the claims to mismeasurement of volume only, conspiracy, unjust enrichment and accounting, and only applies to gas measured in Kansas, Colorado and Wyoming. The court has set an evidentiary hearing in April 2005 to determine whether the amended class should be certified. While we are unable to predict the outcome of this case, we believe that the allegations of this lawsuit are without merit and intend to vigorously defend the action. Any potential liability from this claim cannot currently be reasonably estimated, and no provision has been accrued in our financial statements.

On August 5, 2003, the *Price* plaintiffs served one of our subsidiaries with a new original class action petition styled *Price, et al. v. Gas Pipelines, et al.* The action was filed in the District Court of Stevens County, Kansas, against natural gas pipeline owners and operators. The plaintiffs seek to represent a class of plaintiffs consisting of all similarly situated gas royalty owners either from whom the defendants had purchased natural gas or measured natural gas since January 1, 1974 to the present. The new petition alleges the same improper analysis of gas heating content that had previously been alleged in the *Price* case discussed above until it was removed from the case by the filing of the amended class action petition. In all other respects, the new petition appears to be identical to the amended class action petition in that it has a proposed class of only royalty owners, alleges conspiracy, unjust enrichment and accounting, and only applies to gas measured in Kansas, Colorado and Wyoming. The court has set an evidentiary hearing in April 2005 to determine whether the amended class should be certified. The amount of damages was not specified in the complaint. While we are unable to predict the outcome of this case, we believe that the allegations of this lawsuit are without merit and intend to vigorously defend the action. Any potential liability from this claim cannot currently be reasonably estimated, and no provision has been accrued in our financial statements.

In September 2004, we were served with a lawsuit styled *Burkett, et al. v. J.M. Huber Corp. and XTO Energy Inc.* The action was filed in the District Court of La Plata County, Colorado against us and J.M. Huber Corporation. The plaintiffs allege that the defendants have deducted in their calculation of royalty payments expenses of compression, gathering, treatment, dehydration, or other costs to place the natural gas produced in a marketable condition at a marketable location. The plaintiffs seek to represent a class consisting of all lessors and their successors in interest who own or have owned mineral interests located in La Plata County, Colorado and that are leased to or operated by Huber or us, except to the extent that the lessors or their successors have expressly authorized deduction of post-production expenses from royalties. We acquired the interests of Huber in producing properties in La Plata County effective October 1, 2002, and have assumed the responsibility for certain liabilities of Huber prior to the effective date, which may include liability for post-production deductions made by Huber. We have filed our response and intend to file a response for Huber. As of December 31, 2004, based on an evaluation of available information, we accrued a $3.1 million estimated liability for this claim in our consolidated financial statements. On February 17, 2005, we agreed to a tentative settlement of approximately $5.1 million, resulting in an additional loss of approximately $2 million to be recorded in first quarter 2005.

In December 2004, the U.S. Environmental Protection Agency issued a Compliance Agreement and Final Order to us, which cited certain violations concerning the discharge of produced water and sanitary wastes into Alaska's Cook Inlet from our two operated production platforms from January 2000 through June 2004. We reported these discharges to the EPA as part of our offshore discharge permit monitoring. We have agreed to pay a monetary penalty of $139,000 and have accrued this amount in our financial statements.

We are involved in various other lawsuits and certain governmental proceedings arising in the ordinary course of business. Our management and legal counsel do not believe that the ultimate resolution of these claims, including the lawsuits described above, will have a material effect on our financial position or liquidity, although an unfavorable outcome could have a material adverse effect on the operations of a given interim period or year.

Other

To date, our expenditures to comply with environmental or safety regulations have not been significant and are not expected to be significant in the future. However, new regulations, enforcement policies, claims for damages or other events could result in significant future costs.

To secure tubular goods required to support our drilling program, we have entered a contract with a tubular goods supplier who commits to deliver, at market prices, our next quarter's tubular products ordered by us at least 30 days prior to the beginning of the quarter. There is no minimum order requirement, and our order is subject to modification by the supplier. The contract is cancellable by either party with at least 60 days notice prior to the beginning of the next calendar quarter.

Through December 2004, we have acquired more than 80,000 net acres in the Barnett Shale of North Texas (Note 13). Approximately 60,000 net acres with an estimated value of $69 million are generally subject to lease expiration if initial wells are not drilled within one year. Because we have ample resources to meet the drilling requirements, we currently do not anticipate significant impairment of these leases.

In October 2004, we agreed to acquire an airplane for $17.1 million, either through purchase or lease, and made an initial payment of $6.8 million. We expect to take delivery of the airplane in the first half of 2005.

7. Financial Instruments

We use financial and commodity-based derivative contracts to manage exposures to commodity price and interest rate fluctuations. We do not hold or issue derivative financial instruments for speculative or trading purposes. We also may enter gas physical delivery contracts to effectively provide gas price hedges. Because these contracts are not expected to be net cash settled, they are considered to be normal sales contracts and not derivatives. Therefore, these contracts are not recorded in the financial statements.

All derivatives are recorded on the balance sheet at estimated fair value. Fair value is generally determined based on the difference between the fixed contract price and the underlying market price at the determination date, and/or the value confirmed by the counterparty. Changes in the fair value of effective cash flow hedges are recorded as a component of accumulated other comprehensive income (loss), which is later transferred to earnings when the hedged transaction occurs. Changes in the fair value of derivatives that are not designated as hedges, as well as the ineffective portion of the hedge derivatives, are recorded in derivative fair value (gain) loss in the income statement. This ineffective portion is calculated as the difference between the change in fair value of the derivative and the estimated change in cash flows from the item hedged. Btu swap contracts do not qualify for hedge accounting.

Btu Swap Contracts

In 1995, we entered a contract to sell gas based on crude oil pricing, also referred to as the Enron Btu swap contract. This contract was terminated as a result of the Enron bankruptcy in December 2001. Because the contract pricing was not clearly and closely associated with natural gas prices, it was considered a non-hedge derivative financial instrument, with changes in fair value recorded as a derivative (gain) loss in the income statement.

Prior to termination of the Enron Btu swap contract, we entered Btu swap contracts with another counterparty to effectively defer until August 2005 through July 2006 any cash flow impact related to 25,000 Mcf of daily gas deliveries in 2002 that were to be made under the Enron Btu swap contract. Changes in fair value of these contracts are recorded as a derivative (gain) loss in the income statement. In March 2002, we terminated some of these contracts with maturities of May through December 2002 and received $6.6 million from the counterparty. Because these Btu swap contracts are non-hedge derivatives, most of the $6.6 million gain related to their termination had previously been recorded in 2001 derivative fair value gain.

Commodity Price Hedging Instruments

We periodically enter into futures contracts, energy swaps, collars and basis swaps to hedge our exposure to price fluctuations on crude oil and natural gas sales. When actual commodity prices exceed the fixed price provided by these contracts, we pay this excess to the counterparty, and when actual commodity prices are below the contractually provided fixed price, we receive this difference from the counterparty. We have hedged a portion of our exposure to variability in future cash flows from crude oil and natural gas sales through December 2005. See Note 8.

Derivative Fair Value (Gain) Loss

The components of derivative fair value (gain) loss, as reflected in the consolidated income statements are:

(IN THOUSANDS)	2004	2003	2002
Change in fair value of Btu swap contracts	$ 1,086	$ 5,115	$ 1,046
Change in fair value of other derivatives that do not qualify for hedge accounting	(1,685)	(2,187)	(6,505)
Ineffective portion of derivatives qualifying for hedge accounting	12,488	7,273	2,860
Derivative fair value (gain) loss	$ 11,889	$ 10,201	$ (2,599)

Fair Value of Financial Instruments

Because of their short-term maturity, the fair value of cash and cash equivalents, accounts receivable and accounts payable approximates their carrying values at December 31, 2004 and 2003. The following are estimated fair values and carrying values of our other financial instruments at each of these dates:

	Asset (Liability)			
	December 31, 2004		December 31, 2003	
(IN THOUSANDS)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Derivative Assets:				
Fixed-price natural gas futures and swaps	$ 10,962	$ 10,962	$ 11,997	$ 11,997
Fixed-price crude futures and differential	3,751	3,751	–	–
Derivative Liabilities:				
Fixed-price natural gas futures and swaps	(41,754)	(41,754)	(96,702)	(96,702)
Fixed-price crude futures and differential	(25,879)	(25,879)	–	–
Btu swap contracts	(19,080)	(19,080)	(17,995)	(17,995)
Net derivative asset (liability)	$ (72,000)	$ (72,000)	$ (102,700)	$ (102,700)
Long-term debt	$ (2,042,732)	$ (2,133,818)	$ (1,252,000)	$ (1,275,285)

The fair value of futures, swap and differential agreements is estimated based on the exchange-trade value of NYMEX, basis and differential contracts and market commodity prices for the applicable future periods. The fair value of bank borrowings approximates their carrying value because of short-term interest rate maturities. The fair value of senior notes is based on current market quotes.

Changes in fair value of derivative assets and liabilities are the result of changes in oil and gas prices. Futures and swaps are generally designated as hedges of commodity price risks, and accordingly, changes in their values are predominantly recorded in accumulated other comprehensive income (loss) until the hedged transaction occurs.

Concentrations of Credit Risk

Although our cash equivalents, accounts receivable and derivative assets are exposed to the risk of credit loss, we do not believe such risk to be significant. Cash equivalents are high-grade, short-term securities, placed with highly rated financial institutions. Most of our receivables are from a diverse group of companies including major energy companies, pipeline companies, local distribution companies and end-users in various industries. We currently have greater concentrations of credit with several A- or better rated integrated energy companies. Financial and commodity-based swap contracts expose us to the credit risk of nonperformance by the counterparty to the contracts. This exposure is diversified among major investment grade financial institutions, and we have master netting agreements with counterparties that provide for offsetting payables against receivables from separate derivative contracts. Letters of credit or other appropriate security are obtained as considered necessary to limit risk of loss. Our allowance for collectibility of all accounts receivable was $3.9 million at December 31, 2004 and $6.3 million at December 31, 2003. Our bad debt provision was $232,000 in 2004, $1.3 million in 2003 and $980,000 in 2002. We also recorded a $2.2 million reduction in the allowance for collectibility in 2004.

8. Commodity Sales Commitments

Our policy is to routinely hedge a portion of our production at commodity prices management deems attractive. This policy assures cash flow needed for funding our development program and provides more predictable economic returns for our acquisitions. While there is a risk we may not be able to realize the benefit of rising prices, management plans to continue this strategy because of these benefits.

In addition to selling gas under fixed price physical delivery contracts, we enter futures contracts, energy swaps, collars and basis swaps to hedge our exposure to price fluctuations on natural gas and crude oil sales. When actual commodity prices exceed the fixed price provided by these contracts we pay this excess to the counterparty, and when the commodity prices are below the contractually provided fixed price, we receive this difference from the counterparty. We have hedged a portion of our exposure to variability in future cash flows from natural gas and crude oil sales through December 2005.

Natural Gas

We have entered into natural gas futures contracts and swap agreements that effectively fix prices for the production and periods shown below. Prices to be realized for hedged production may be less than these fixed prices because of location, quality and other adjustments. See Note 7 regarding accounting for commodity hedges.

	Base Production		Production Related to 2004 Acquisitions		Total	
Production Period	Mcf per Day	Average NYMEX Price per Mcf	Mcf per Day	Average NYMEX Price per Mcf	Mcf per Day	Average NYMEX Price per Mcf
2005 January to December	200,000	$ 5.79	50,000	$ 6.34	250,000	$ 5.90

The price we receive for our gas production is generally less than the NYMEX price because of adjustments for delivery location ("basis"), relative quality and other factors. We have entered basis swap agreements that effectively fix the basis adjustment for the following delivery locations and periods:

	Delivery Location				
Production Period	Arkoma	Houston Ship Channel	Rockies	San Juan Basin	Total
2005					
January					
Mcf per day	10,000	210,000	30,000	70,000	320,000
Basis per Mcf (a)	$ (0.06)	$ (0.21)	$ (0.77)	$ (0.67)	
February to March					
Mcf per day	10,000	210,000	10,000	70,000	300,000
Basis per Mcf (a)	$ (0.06)	$ (0.21)	$ (0.71)	$ (0.67)	
April to June					
Mcf per day	–	270,000	5,000	30,000	305,000
Basis per Mcf (a)	–	$ (0.14)	$ (0.75)	$ (0.68)	
July to August					
Mcf per day	–	270,000	5,000	30,000	305,000
Basis per Mcf (a)	–	$ (0.12)	$ (0.75)	$ (0.68)	
September					
Mcf per day	–	250,000	5,000	30,000	285,000
Basis per Mcf (a)	–	$ (0.12)	$ (0.75)	$ (0.68)	
October					
Mcf per day	–	270,000	5,000	30,000	305,000
Basis per Mcf (a)	–	$ (0.14)	$ (0.75)	$ (0.68)	
November to December					
Mcf per day	–	220,000	10,000	40,000	270,000
Basis per Mcf (a)	–	$ (0.17)	$ (0.76)	$ (0.68)	

(a) Reductions to NYMEX gas prices for delivery location.

Net losses on futures and basis swap hedge contracts decreased gas revenue by $156.1 million in 2004 and $193 million in 2003. Net gains on futures and basis swap hedge contracts increased gas revenue by $57.4 million in 2002. Including the effect of fixed price physical delivery contracts, all hedging activities increased gas revenue by $95.4 million in 2002. There were no fixed price physical delivery contracts in 2003 or 2004. As of December 31, 2004, an unrealized pre-tax derivative fair value loss of $28.1 million, related to cash flow hedges of gas price risk, was recorded in accumulated other comprehensive income (loss). This fair value loss is expected to be reclassified into earnings in 2005. The actual reclassification to earnings will be based on mark-to-market prices at the contract settlement date.

The settlement of futures contracts and basis swap agreements related to January 2005 gas production reduced gas revenue by approximately $1.1 million, or $0.04 per Mcf.

Crude Oil

In connection with our 2004 acquisitions from ExxonMobil Corporation and ChevronTexaco Corporation (Note 13), we entered oil futures contracts to sell, through December 2005, 10,000 Bbls per day at an average West Texas Intermediate NYMEX price of $35.91 per Bbl and 5,000 Bbls per day at an average West Texas Intermediate NYMEX price of $43.28 per Bbl. For 5,000 Bbls per day of production hedged at $35.91 per Bbl, we entered a crude sweet and sour differential swap of $3.05 per Bbl, to effectively fix the price for crude sour production at $32.86 per Bbl. Prices to be realized for hedged oil production are expected to be less than the NYMEX price because of location, quality and other adjustments.

In 2004, net losses on futures and differential swap hedge contracts decreased oil revenue by $15.5 million. Net losses on oil futures hedge contracts decreased oil revenue by $3.9 million in 2003. During 2002, net losses on oil futures hedge contracts decreased oil revenue by $1.3 million, while changes in fair value of sour oil basis swap contracts resulted in a derivative fair value gain of $300,000. As of December 31, 2004, an unrealized pre-tax derivative fair value loss of $17 million related to cash flow hedges of oil price risk was recorded in accumulated other comprehensive income (loss). This entire fair value loss is expected to be reclassified into earnings in 2005. The actual reclassification to earnings will be based on mark-to-market prices at the contract settlement date.

The settlement of futures contracts and crude sweet and sour differential swaps related to January 2005 production reduced oil revenue by approximately $3.1 million, or $2.84 per Bbl.

Physical Delivery Contracts

From August 1995 through July 1998 we received an additional $0.30 to $0.35 per Mcf on 10,000 Mcf of gas per day. In exchange therefor, we agreed to sell 34,344 Mcf per day at the index price in 2001 and 35,500 Mcf per day from 2002 through July 2005 at a price of approximately 10% of the average NYMEX futures price for intermediate crude oil. See Note 7 regarding accounting for this contract, also referred to as the Enron Btu swap contract, which was terminated as a result of the Enron bankruptcy, and regarding a related derivative commitment with another counterparty.

In addition to the Enron Btu swap contract, Enron Corporation was a purchaser of natural gas under other physical delivery contracts and was counterparty to some of our hedge derivative contracts at the time of its bankruptcy in December 2001. In settlement of all obligations, we paid Enron $6 million in December 2002. As a result of this settlement, in 2002 we recognized $14.1 million in previously unrecognized gas revenue related to physical delivery contracts and a gain of $2.1 million.

In 1998, we sold a production payment, payable from future production from certain properties acquired in an acquisition, to EEX Corporation for $30 million. Under the terms of the production payment conveyance and related delivery agreement, we committed to deliver to EEX a total of approximately 34.3 Bcf (27.8 Bcf net to our interest) of gas during the 10-year period beginning January 1, 2002, with scheduled deliveries by year, subject to certain variables. EEX will reimburse us for all royalty and production and property tax payments related to such deliveries. EEX will also pay us an operating fee of $0.257 per Mcf for deliveries, which fee will be escalated annually at a rate of 5.5%. In 2001 and 2002, we repurchased 18.3 Bcf (14.8 Bcf net) of gas under the production payment for $20.7 million. We expect to begin delivery of the remaining 16.0 Bcf (13.0 Bcf net) of gas in 2006.

9. Equity

Stock Splits

We effected a four-for-three stock split on March 18, 2003 and a five-for-four stock split on March 17, 2004, and will effect a four-for-three stock split on March 15, 2005. All common stock shares, treasury stock shares and per share amounts have been retroactively restated to reflect these stock splits.

Common Stock

The following reflects our common stock activity:

	Shares Issued			Shares in Treasury		
(in thousands)	2004	2003	2002	2004	2003	2002
Balance, January 1	312,335	301,633	293,308	–	19,462	18,258
Issuance/vesting and forfeiture of performance shares	2,448	4,444	2,224	1,216	1,585	1,045
Stock option and warrant exercises	1,937	4,456	6,101	–	–	4
Treasury stock purchases	–	–	–	34	151	155
Common stock offering	31,708	23,000	–	–	–	–
Cancellation of treasury shares	–	(21,198)	–	–	(21,198)	–
Balance, December 31	348,428	312,335	301,633	1,250	–	19,462

In May 2004, we completed a public offering of 31.7 million shares of common stock at $18.92 per share. After underwriting discount and other offering costs of $19.7 million, net proceeds of $580.3 million were used to reduce bank borrowings that funded our producing property acquisitions from ExxonMobil Corporation and our deposit on the ChevronTexaco acquisition (Note 13).

In April 2003, we completed a public offering of 23 million shares of common stock at $11.25 per share. After underwriting discount and other offering costs of $10.8 million, net proceeds from the offering of $248 million and net proceeds from the concurrent sale of senior notes (Note 3) were used to fund our producing property acquisition from units of Williams of Tulsa, Oklahoma (Note 13), to redeem our $8\frac{3}{4}$% senior subordinated notes and to reduce bank debt.

In January 2005, we announced our agreement to purchase Antero Resources Corporation, which will partially be funded by issuance of 13.3 million shares of common stock (Note 13).

Treasury Stock

In February 2004, the Board of Directors authorized the cancellation of treasury shares as of December 31, 2003. This retirement of treasury shares is reflected in the December 31, 2003 consolidated balance sheet, resulting in a reduction of treasury stock and additional paid-in-capital of $102 million, and a reduction in shares in treasury and shares issued of 21.2 million shares.

In August 2004, our Board of Directors authorized the repurchase of up to 20 million shares of our common stock which may be purchased from time to time in open market or negotiated transactions. This authorization effectively replaced the share repurchase authorization remaining from May 2000. As of December 31, 2004, we have repurchased 33,600 shares at a cost of $812,000.

Stockholder Rights Plan

In August 1998, the Board of Directors adopted a stockholder rights plan that is designed to assure that all stockholders receive fair and equal treatment in the event of any proposed takeover of the Company. Under this plan, one preferred share purchase right is attached to each outstanding share of common stock. Each right entitles stockholders to buy one one-thousandth of a share of newly created Series A Junior Participating Preferred Stock at an exercise price of $80, subject to adjustment in the event a person acquires or makes a tender or exchange offer for 15% or more of the outstanding common stock. In such event, each right entitles the holder (other than the person acquiring 15% or more of the outstanding common stock) to purchase shares of common stock with a market value of twice the right's exercise price. At any time prior to such event, the Board of Directors may redeem the rights at one cent per right. The rights can be transferred only with common stock and expire in August 2008.

Shelf Registration Statement

In February 2005, we filed a shelf registration statement with the Securities and Exchange Commission to potentially offer securities which could include debt securities, preferred stock, common stock, or warrants to purchase debt or stock. The total face amount of securities that can be offered is $2.5 billion, at prices and on terms to be determined at the time of sale. Net proceeds from the sale of such securities will be used for general corporate purposes, including reduction of bank debt.

Common Stock Warrants

As partial consideration for producing properties acquired in December 1997, we issued warrants to purchase 4.8 million shares of common stock at a price of $3.02 per share for a period of five years. These warrants, valued at $5.7 million when issued and recorded as additional paid-in capital, were exercised in August 2002, resulting in an increase to common stock and additional paid-in capital of $14.3 million.

Our purchase of Antero Resources Corporation will be partially funded by issuance of five-year warrants to purchase 2 million shares of common stock at $27.00 per share (Note 13).

Common Stock Dividends

The Board of Directors declared quarterly dividends of $0.0045 per common share for each quarter in 2002, $0.006 per common share for each quarter in 2003, $0.0075 per common share for first and second quarter 2004 and $0.0375 per common share for third and fourth quarter 2004. In February 2005, the Board of Directors declared a first quarter 2005 dividend of $0.05 per common share after the four-for-three stock split is effected on March 15, 2005.

In August 2003, our Board of Directors declared a dividend of 0.0044 units of Cross Timbers Royalty Trust for each share of common stock outstanding on September 2, 2003. This dividend, totaling 1,360,000 trust units, was distributed on September 18, 2003, and was recorded at the fair value of the units on that date of $28.2 million.

The determination of the amount of future dividends, if any, to be declared and paid is at the sole discretion of the Board of Directors and will depend on our financial condition, earnings and cash flow from operations, the level of our capital expenditures, our future business prospects and other matters the Board of Directors deems relevant.

See Note 12.

10. Earnings Per Share

The following reconciles earnings (numerator) and shares (denominator) used in the computation of basic and diluted earnings per share:

(in thousands, except per share data)	Earnings	Shares	Earnings per Share
2004			
Basic	$ 507,882	332,907	$ 1.53
Effect of dilutive securities:			
Stock options	–	2,774	
Diluted	$ 507,882	335,681	$ 1.51
2003			
Basic	$ 288,279	299,665	$ 0.96
Effect of dilutive securities:			
Stock options	–	4,087	
Diluted	$ 288,279	303,752	$ 0.95
2002			
Basic	$ 186,059	277,834	$ 0.67
Effect of dilutive securities:			
Stock options	–	1,378	
Warrants	–	1,874	
Diluted	$ 186,059	281,086	$ 0.66

11. Supplemental Cash Flow Information

The consolidated statements of cash flows exclude the following non-cash transactions:

- Distribution of 1,360,000 Cross Timbers Royalty Trust units as a dividend to common stockholders in 2003 (Note 9)
- Exchange of nonstrategic working and royalty interests for nonproducing acres in August 2004 (Note 2)
- The following performance share activity (Note 12):
  - Grants of 2.6 million shares in 2004, 4.4 million shares in 2003 and 2.4 million shares in 2002
  - Vesting of 3.2 million shares in 2004, 3.5 million in 2003 and 2.8 million shares in 2002
  - Forfeiture of 20,000 shares in 2003

Interest payments in 2004 totaled $77 million (including $2.6 million of capitalized interest), $60.9 million in 2003 (including $2.2 million of capitalized interest) and $52.1 million in 2002 (including $4.3 million of capitalized interest). Net income tax payments were $49.7 million during 2004, $5.3 million during 2003 and $405,000 during 2002.

Because we do not recognize compensation related to stock options granted, the tax benefit realized upon exercise of stock options is recorded as an increase in additional paid-in capital. This tax benefit has increased our net operating loss carryforwards (Note 4) and is reflected in our consolidated statements of cash flows when these carryforwards were utilized, primarily in 2004. This tax benefit from exercise of stock options was $17.9 million in 2004, $22.7 million in 2003 and $1.8 million in 2002.

12. Employee Benefit Plans

401(k) Plan

We sponsor a 401(k) benefit plan that allows employees to contribute and defer a portion of their wages. We match employee contributions of up to 10% of wages, subject to annual dollar maximums established by the federal government. Employee contributions vest immediately while our matching contributions vest 100% upon completion of three years of service. All employees over 21 years of age may participate. Company contributions under the plan were $6.8 million in 2004, $5.2 million in 2003 and $4.5 million in 2002.

Effective January 1, 2001, we adopted a medical plan for employees who retire at age 55 or over, as well as directors age 55 or over, with a minimum of five years service. During 2003, our retiree medical plan was amended to provide benefits to employees and directors when their combined age and qualified years of service total 60, with a minimum age of 45 and a minimum of five years of service. Benefits under the plan are the same as for active employees, and continue until the retired employee or director or the employee's or director's dependents are eligible for Medicare or another similar federal health insurance program. Post-retirement medical benefits are not prefunded but are paid when incurred. The status of our post-retirement health plan for 2004, 2003 and 2002 is as follows:

	December 31		
(in thousands)	2004	2003	2002
Change in benefit obligation:			
Benefit obligation at January 1	$ 3,122	$ 3,096	$ 1,078
Service cost	456	729	477
Interest cost	201	275	185
Plan amendments	–	2,380	490
Actuarial (gain) loss	256	(3,273)	904
Benefit payments	(100)	(85)	(38)
Benefit obligation at December 31	$ 3,935	$ 3,122	$ 3,096
Amounts recognized in the consolidated balance sheet:			
Funded status	$ (3,935)	$ (3,122)	$ (3,096)
Unrecognized net actuarial (gain) loss	(2,704)	(3,391)	698
Unrecognized prior service cost	2,332	2,738	424
Accrued benefit liability, as recognized in the consolidated balance sheet at December 31	$ (4,307)	$ (3,775)	$ (1,974)
Components of net periodic benefit cost:			
Service cost	$ 456	$ 729	$ 477
Interest cost	201	275	185
Amortization of prior service cost	406	66	66
Recognized net actuarial (gain) loss	(431)	731	159
Net periodic benefit cost	$ 632	$ 1,801	$ 887

Unrecognized net actuarial gain and prior service costs are amortized to expense over the lesser of the estimated average remaining service life of plan participants or seven years. Including such amortization, the 2005 accrued benefit cost is expected to be approximately $1 million.

The following are assumptions used by us to determine our benefit obligation as of December 31 of each of the years presented:

	2004	2003	2002
Weighted average discount rate	6%	6.5%	6.5%
Health care cost trend rate assumed for the following year	9%	9%	9%
Rate to which the cost trend rate is assumed to decline (ultimate trend rate)	6%	6%	6%
Year that the rate reaches the ultimate trend rate	2010	2009	2008

Assumed health care cost trends have a significant effect on the amounts reported for health care plans. A one percentage point change in assumed health care cost trend rates would have the following estimated effects as of December 31, 2004:

	One Percentage Point	
(in thousands)	Increase	Decrease
Effect on total service and interest cost	$ 105	$ 89
Effect on the post-retirement benefit obligation	$ 513	$ 450

The following are projected benefit payments, which reflect expected future service, for the next ten years:

(IN THOUSANDS)	
2005	$ 155
2006	181
2007	191
2008	231
2009	267
2010 - 2014	2,326
Total	$ 3,351

Stock Incentive Plans

In November 2004, stockholders approved the 2004 Stock Incentive Plan under which 24 million shares of common stock are available for grants of stock awards. Prior to approval of the 2004 Plan, grants of stock awards were made pursuant to the 1998 Stock Incentive Plan. No further grants will be made under the 1998 Plan. Stock award grants are subject to the provision that awards outstanding at any given time under all incentive plans may not exceed six percent of common stock outstanding at the time such grants are made. The maximum term of stock awards is ten years under the 1998 Plan and seven years under the 2004 plan. Stock options granted under the 2004 Plan generally vest and become exercisable ratably over a three-year period, with provision for accelerated vesting when the common stock price reaches specified levels as determined by the Compensation Committee of the Board of Directors. There were 19.3 million options outstanding under both plans at December 31, 2004, including 4.1 million that were exercisable at that date. The remaining 15.2 million options vested when the common stock price reached specified levels in February 2005.

Nonemployee directors are each eligible to receive discretionary stock awards under the 2004 Plan covering up to 20,000 shares annually, as approved by the Corporate Governance and Nominating Committee and the Board of Directors. In November 2004, nonemployee directors were granted a total of 88,000 stock options which were outstanding at December 31, 2004 and vested when the common stock price reached specified levels in February 2005. Under the 1998 Plan, nonemployee directors previously received automatic annual grants of unrestricted common shares that totaled 18,000 shares in each of 2004, 2003 and 2002. In February 2005, nonemployee directors received a total of 18,000 unrestricted shares under the 2004 Plan.

Performance Shares

Performance shares granted under the 2004 and 1998 Plans are subject to restrictions determined by the Compensation Committee of the Board of Directors and are subject to forfeiture if performance criteria are not met. Otherwise, holders of performance shares generally have all the voting, dividend and other rights of other common stockholders. To date, the performance criteria for all awards has been the achievement of specified increases in the common stock price above the market price at the grant date. The following summarizes performance share activity for each year:

	December 31		
(IN THOUSANDS, EXCEPT PER SHARE DATA)	2004	2003	2002
Shares granted to key employees	2,576	4,431	2,353
Shares vested when common stock price reached specified levels	3,240	3,470	2,754
Shares forfeited	–	20	–
Weighted average fair value of shares when granted	$ 20.94	$ 14.71	$ 9.73
Treasury stock purchases related to vested shares	$ 24,105	$ 22,741	$ 10,276
Non-cash performance share compensation	$ 67,184	$ 50,826	$ 26,990

At December 31, 2004, deferred compensation of $[illegible] million was recorded, based on the year-end common stock price, as an offset to additional paid-in-capital for 797,533 performance shares outstanding. These performance shares vest when the common stock reaches the following prices:

Shares Outstanding at December 31, 2004	Vesting Price
397,500	$ 28.13
2,533	$ 28.50
397,500	$ 31.88
797,533	

Management assesses whether the vesting period of stock-based awards can be reasonably estimated. When management is able to reasonably estimate a probable vesting period, compensation is recognized ratably over the estimated vesting period or at actual vesting, if earlier. Performance shares outstanding at December 31, 2004 were granted to key employees other than executive officers in September and November 2004. As of December 31, 2004, management estimated a reasonably probable vesting period of one year for performance share awards that vest at $28.13 and $28.50, resulting in related compensation of $2.8 million recorded in 2004. As of February 2005, all performance shares outstanding at December 31, 2004 vested, resulting in remaining compensation of $21.1 million to be recorded in first quarter 2005.

During second quarter 2004, the Company began granting cash-equivalent, or phantom, performance shares to executive officers in lieu of performance shares. Vested cash-equivalent performance shares are payable solely in cash in an amount equal to the fair market value of the underlying common stock upon vesting. During 2004, 967,000 cash-equivalent performance shares were issued to executive officers. All cash-equivalent performance shares vested in 2004 resulting in compensation expense of $22.3 million. As of December 31, 2004, there are no cash-equivalent performance shares outstanding.

In September 2004, the Compensation Committee of the Board of Directors announced that it intended to restructure the Company's equity incentive program to discontinue the use of performance shares for executive officers and to provide that all future grants to the officers would be in the form of options or other stock appreciation shares. As a result, in October 2004, the Compensation Committee of the Board of Directors amended the change in control performance share grant agreements to delete the provisions regarding the grant of performance shares for every $0.75 increment in the price of the common stock and to provide that, immediately prior to a change in control, executive officers will receive a lump-sum cash payment equal to the value of 1,667,000 shares of common stock on the date of the change in control. A provision, providing that certain officers will also receive a total grant of 517,000 performance shares immediately prior to a change in control without regard to the price of our common stock, has been revised to provide that such payment will be in cash and not in shares of common stock. All amounts to be granted under these agreements will be adjusted for any future stock splits or other extraordinary transactions. If the executive officers are subject to the 20% parachute excise tax, the Company will pay the executive officer an additional amount to "gross up" the payment so that the executive officer will receive the full amount due under the terms of the amended change in control grant agreement after payment of the excise tax.

The following summarizes option activity and balances from 2002 through 2004:

	Weighted Average Exercise Price	Stock Options
2002		
Beginning of year	$ 8.07	15,413,893
Grants	10.24	1,104,677
Exercises	6.52	(1,591,438)
Forfeitures	7.90	(73,063)
End of year	8.40	14,854,069
Exercisable at end of year	8.33	14,339,138
2003		
Beginning of year	$ 8.40	14,854,069
Grants	15.06	3,530,208
Exercises	8.46	(10,430,123)
Forfeitures	13.88	(55,000)
End of year	11.15	7,899,154
Exercisable at end of year	9.22	5,310,993
2004		
Beginning of year	$ 11.15	7,899,154
Grants	24.86	16,229,845
Exercises	13.17	(4,794,177)
Forfeitures	15.14	(15,000)
End of year	22.16	19,319,822
Exercisable at end of year	11.99	4,092,488

The following summarizes information about outstanding options at December 31, 2004:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number	Weighted Average Remaining Term	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
$ 5.23 - $ 7.85	1,948,925	6.1 years	$ 7.15	1,948,925	$ 7.15
$ 7.86 - $10.46	1,099,233	7.0 years	$ 9.43	1,099,233	$ 9.43
$10.47 - $13.08	19,329	8.5 years	$ 11.67	19,329	$ 11.67
$13.09 - $15.70	55,667	8.9 years	$ 15.14	55,667	$ 15.14
$15.71 - $20.93	20,000	9.4 years	$ 19.22	20,000	$ 19.22
$20.94 - $26.16	16,176,668	7.2 years	$ 24.88	949,334	$ 24.58
	19,319,822	7.1 years	$ 22.16	4,092,488	$ 11.99

Estimated Fair Value of Grants

Using the Black-Scholes option-pricing model and the following assumptions, the weighted average fair value of option grants was estimated to be $5.34 in 2004, $5.47 in 2003 and $4.36 in 2002. Black-Scholes and alternative option-pricing models do not consider the effects of forfeitability and nontransferability on the valuation of employee stock options.

	2004	2003	2002
Risk-free interest rates	3.5%	3.1%	3.1%
Dividend yield	0.6%	0.2%	0.2%
Weighted average expected lives	3 years	4 years	4 years
Volatility	26%	42%	50%

Pro Forma Effect of Recording Stock-Based Compensation at Estimated Fair Value

The following are pro forma earnings available to common stock and earnings per common share for 2004, 2003 and 2002, as if stock-based compensation had been recorded at the estimated fair value of stock awards at the grant date, as prescribed by SFAS No. 123, *Accounting for Stock-Based Compensation:*

(IN THOUSANDS, EXCEPT PER SHARE DATA)		2004	2003	2002
Earnings available to common stock:				
As reported		$ 507,882	$ 288,279	$ 186,059
Pro forma		$ 487,391	$ 289,311	$ 183,840
Earnings per common share:				
Basic	As reported	$ 1.53	$ 0.96	$ 0.67
	Pro forma	$ 1.46	$ 0.96	$ 0.66
Diluted	As reported	$ 1.51	$ 0.95	$ 0.66
	Pro forma	$ 1.45	$ 0.95	$ 0.65

13. Acquisitions

In January 2004, we acquired producing properties located primarily in East Texas and northwestern Louisiana in three separate transactions totaling $243 million after adjustments of $6 million for net revenues, preferential right elections and other items from the effective date of the transaction. The acquisitions were funded with a portion of the proceeds from the sale of 4.9% senior notes in January 2004 (Note 3) and are subject to typical post-closing adjustments.

From February through April 2004, we purchased $223.1 million of properties located primarily in the Barnett Shale of North Texas and in the Arkoma Basin. These acquisitions are subject to typical post-closing adjustments. Funding was provided by bank debt and cash flow from operations.

In two separate transactions during April 2004, we acquired predominantly oil-producing properties in the Permian Basin of West Texas and in the Powder River Basin of Wyoming from ExxonMobil Corporation for a total adjusted purchase price of $336 million, including a contingent payable of up to $5 million dependent on earnings from one property in the following year. The acquisitions were funded with bank borrowings that were repaid with proceeds from the sale of common stock in May 2004 (Note 9) and are subject to typical post-closing adjustments.

In May 2004, we entered an agreement with ChevronTexaco Corporation to acquire properties for a stated purchase price of $1.1 billion. The acquisition closed on August 16, 2004. After adjustments for net revenues from the January 1, 2004 effective date, preferential purchase right elections exercised in November and December 2004, and other typical closing adjustments, the adjusted purchase price was approximately $930 million. Post-closing adjustments for final net revenues, volume balancing and income tax effects will be made within twelve months. The acquisition was funded through existing bank credit facilities and the sale of common stock in May 2004. These properties expand our operations in the Permian Basin and our Eastern and Mid-Continent regions, and add new coal bed methane properties in the Rocky Mountains and a new operating region in South Texas.

Two acquisitions in 2004 were purchases of corporations that primarily owned producing and nonproducing properties. After purchase accounting adjustments, including a $72.3 million step-up adjustment for deferred income taxes, the cost of all producing properties acquired in 2004 was $1.9 billion.

In May 2003, we acquired from Williams of Tulsa, Oklahoma natural gas and coal bed methane producing properties in the Raton Basin of Colorado, the Hugoton Field of southwestern Kansas and the San Juan Basin of New Mexico and Colorado. The adjusted purchase price was $381 million, which was financed with proceeds from our sale of senior notes (Note 3) and common stock (Note 9).

In June 2003, we acquired coal bed methane and natural gas producing properties in the San Juan Basin of New Mexico and Colorado from Markwest Hydrocarbon, Inc. for an adjusted purchase price of $51 million, which was funded through bank borrowings. The acquisition is subject to typical post-closing adjustments.

In October 2003, we announced the completion of property transactions which increased our positions in East Texas, Arkansas and the San Juan Basin of New Mexico for a total cost of $100 million. The purchases were funded with existing credit facilities and are subject to typical post-closing adjustments.

Acquisitions were recorded using the purchase method of accounting. The following presents our unaudited pro forma results of operations for 2003 and 2002, as if the ChevronTexaco, ExxonMobil and Williams acquisitions were made at the beginning of each period. These pro forma results are not necessarily indicative of future results.

(IN THOUSANDS, EXCEPT PER SHARE DATA)	PRO FORMA (UNAUDITED) YEAR ENDED DECEMBER 31 2004	2003
Revenues	$ 2,186,961	$ 1,645,307
Net income before cumulative effect of accounting change	$ 574,233	$ 381,985
Net income	$ 574,233	$ 383,763
Earnings per common share:		
Basic	$ 1.68	$ 1.19
Diluted	$ 1.66	$ 1.17
Weighted average shares outstanding	342,211	322,990

In January 2005, we announced an agreement to purchase privately held Antero Resources Corporation, a prominent Barnett Shale producer, for cash and equity consideration valued at approximately $685 million. Consideration includes $337.5 million in cash, 13.3 million shares of our common stock and five-year warrants to purchase another 2 million shares of our common stock at $27 per share. The purchase agreement was amended in February 2005 to include Antero's gas gathering assets and related bank debt of $175 million. The transaction is expected to close April 1, 2005. The booked acquisition cost will include customary non-cash adjustments, including a step-up adjustment for deferred income taxes. The cash consideration for the acquisition will initially be provided through cash flow from operations and existing bank credit facilities.

14. Quarterly Financial Data (Unaudited)

The following are summarized quarterly financial data for the years ended December 31, 2004 and 2003:

(IN THOUSANDS, EXCEPT PER SHARE DATA)	QUARTER 1ST	2ND	3RD	4TH
2004				
Revenues	$ 394,764	$ 444,749	$ 507,430	$ 600,658
Gross profit (a)	$ 215,777	$ 254,986	$ 284,446	$ 329,164
Net income	$ 94,136	$ 99,089	$ 140,782	$ 173,875
Earnings per common share (b)				
Basic	$ 0.30	$ 0.30	$ 0.41	$ 0.50
Diluted	$ 0.30	$ 0.30	$ 0.40	$ 0.50
Average shares outstanding	312,727	326,087	345,281	347,118
2003				
Revenues	$ 253,484	$ 282,159	$ 322,058	$ 331,854
Gross profit (a)	$ 125,532	$ 140,274	$ 172,789	$ 170,744
Income before cumulative effect of accounting change	$ 64,452	$ 57,335	$ 102,806	$ 61,908
Cumulative effect of accounting change, net of tax	1,778	–	–	–
Net income	$ 66,230	$ 57,335	$ 102,806	$ 61,908
Earnings per common share (b)				
Basic:				
Net income before cumulative effect of accounting change	$ 0.22	$ 0.19	$ 0.34	$ 0.20
Cumulative effect of accounting change, net of tax	0.01	–	–	–
Net income	$ 0.23	$ 0.19	$ 0.34	$ 0.20

(IN THOUSANDS, EXCEPT PER SHARE DATA)	QUARTER 1ST	2ND	3RD	4TH
Diluted:				
Net income before cumulative effect of accounting change	$ 0.22	$ 0.19	$ 0.33	$ 0.20
Cumulative effect of accounting change, net of tax	0.01	–	–	–
Net income	$ 0.23	$ 0.19	$ 0.33	$ 0.20
Average shares outstanding	282,263	300,275	306,320	309,431

(a) Operating income before general and administrative expense.

(b) Because quarterly earnings per share is based on the weighted average shares outstanding during the quarter, the sum of quarterly earnings per share may not equal earnings per share for the year.

15. Supplementary Financial Information for Oil and Gas Producing Activities (Unaudited)

All of our operations are directly related to oil and gas producing activities located in the United States.

Costs Incurred Related to Oil and Gas Producing Activities

The following table summarizes costs incurred whether such costs are capitalized or expensed for financial reporting purposes:

(IN THOUSANDS)	2004	2003	2002
Acquisitions:			
Producing properties	$ 1,948,995 (a)	$ 623,775	$ 354,110
Undeveloped properties	49,973	5,678	3,977
Development (b) (c)	572,073	445,914	352,115
Exploration:			
Successful exploratory drilling costs	4,516	14,327	1,968
Geological and geophysical studies	8,098	639	792
Dry hole expense	–	26	242
Rental expense and other	2,415	1,146	1,152
Asset retirement obligation accrual recorded upon acquiring and drilling wells	59,864 (d)	13,879 (e)	–
Total Costs Incurred	$ 2,645,934	$ 1,105,384	$ 714,356

(a) Includes a deferred income tax step-up adjustment of $72.3 million.

(b) Includes capitalized interest of $2.6 million in 2004, $2.2 million in 2003 and $4.3 million in 2002.

(c) Amounts have been restated from previously reported amounts to separately disclose successful exploratory drilling costs.

(d) Includes revisions of $6 million in 2004.

(e) Excludes $75.3 million recorded upon adoption of SFAS No. 143 on January 1, 2003.

Exploratory Well Costs

The following summarizes changes in capitalized costs for exploratory wells in process of drilling:

(IN THOUSANDS)	2004	2003	2002
Exploratory wells in process of drilling, January 1	$ 3,390	$ 1,709	$ 816
Exploratory drilling costs incurred	4,516	14,353	2,210
Successful wells transferred to producing properties	(5,965)	(12,646)	(1,075)
Unsuccessful well costs charged to expense	–	(26)	(242)
Exploratory wells in process of drilling, December 31	$ 1,941	$ 3,390	$ 1,709

There were no completed exploratory wells awaiting determination of proved reserves at December 31, 2004, 2003 or 2002.

Proved Reserves

Our proved oil and gas reserves have been estimated by independent petroleum engineers. Proved reserves are the estimated quantities that geologic and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are the quantities expected to be recovered through existing wells with existing equipment and operating methods. Due to the inherent uncertainties and the limited nature of reservoir data, such estimates are subject to change as additional information becomes available. The reserves actually recovered and the timing of production of these reserves may be substantially different from the original estimate. Revisions result primarily from new information obtained from development drilling and production history and from changes in economic factors. Proved reserves exclude volumes deliverable to others under production payments.

Standardized Measure

The standardized measure of discounted future net cash flows and changes in such cash flows are prepared using assumptions required by the Financial Accounting Standards Board. Such assumptions include the use of year-end prices for oil and gas and year-end costs for estimated future development and production expenditures to produce year-end estimated proved reserves. Year-end prices are not adjusted for the effect of hedge derivatives. Discounted future net cash flows are calculated using a 10% rate. Estimated future income taxes are calculated by applying year-end statutory rates to future pre-tax net cash flows, less the tax basis of related assets and applicable tax credits.

As of December 31, 2003, estimated well abandonment costs, net of salvage, are deducted from the standardized measure using year-end costs. Such abandonment costs are recorded as a liability on the consolidated balance sheet, using estimated values of the projected abandonment date and discounted using a risk-adjusted rate at the time the well is drilled or acquired (Note 5).

In our prior reports, the estimated future net cash flows from proved reserves and related present value amounts were reported before reduction for operated overhead expense. Operated overhead is a component of production expense in the consolidated income statement, and is an allocation from general and administrative expense of the costs estimated to support the production function. As part of its periodic review of our filings, the staff of the Securities and Exchange Commission concluded that production expense components for proved reserve disclosures should be consistent with components of production expense recorded in the financial statements. Accordingly, we have restated estimated future net cash flows and the related present value amounts for all years presented, resulting in a reduction to these amounts of approximately 2% at December 31, 2003 and 3% at December 31, 2002.

The standardized measure does not represent management's estimate of our future cash flows or the value of proved oil and gas reserves. Probable and possible reserves, which may become proved in the future, are excluded from the calculations. Furthermore, year-end prices used to determine the standardized measure are influenced by seasonal demand and other factors and may not be the most representative in estimating future revenues or reserve data.

(in thousands)	Gas (Mcf)	Natural Gas Liquids (Bbls)	Oil (Bbls)	Natural Gas Equivalents (Mcfe)
Proved Reserves				
December 31, 2001	2,235,478	20,299	54,049	2,681,566
Revisions	76,400	2,433	5,465	123,788
Extensions, additions and discoveries	426,541	2,395	1,144	447,775
Production	(187,583)	(1,850)	(4,757)	(227,225)
Purchases in place	330,387	2,156	449	346,017
Sales in place	(42)	–	(1)	(48)
December 31, 2002	2,881,181	25,433	56,349	3,371,873
Revisions	(11,644)	5,487	1,792	32,030
Extensions, additions and discoveries	559,773	1,610	424	571,977
Production	(243,979)	(2,359)	(4,724)	(286,477)
Purchases in place	465,732	4,508	2,204	506,004
Sales in place	(6,824)	(1)	(614)	(10,514)
December 31, 2003	3,644,239	34,678	55,431	4,184,893
Revisions	(96,139)	(146)	3,001	(79,009)
Extensions, additions and discoveries	755,385	3,730	4,176	802,821
Production	(305,453)	(2,739)	(8,307)	(371,729)
Purchases in place	716,471	2,933	98,205	1,323,299
December 31, 2004	4,714,503	38,456	152,506	5,860,275
Proved Developed Reserves				
December 31, 2001	1,452,222	14,774	41,231	1,788,252
December 31, 2002	2,042,661	19,367	47,178	2,441,931
December 31, 2003	2,651,259	28,187	47,882	3,107,673
December 31, 2004	3,252,711	30,019	134,382	4,239,117

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Reserves

	December 31		
(in thousands)	2004	2003	2002
Future cash inflows	$ 34,027,144	$ 23,213,223	$ 14,734,787
Future costs:			
Production	(8,841,912)	(5,636,953)	(3,881,188)
Development	(1,580,173)	(875,665)	(687,723)
Future net cash flows before income tax	23,605,059	16,700,605	10,165,876
Future income tax	(7,366,185)	(5,142,301)	(3,017,334)
Future net cash flows	16,238,874	11,558,304	7,148,542
10% annual discount	(7,836,431)	(5,568,619)	(3,392,100)
Standardized measure (a)	$ 8,402,443	$ 5,989,685	$ 3,756,442

(a) Before income tax, the year-end standardized measure (or discounted present value of future net cash flows) was $12.2 billion for 2004, $8.6 billion for 2003 and $5.3 billion for 2002.

Changes in Standardized Measure of Discounted Future Net Cash Flows (a)

(IN THOUSANDS)	2004	2003	2002
Standardized measure, January 1	$ 5,989,685	$ 3,756,442	$ 1,473,777
Revisions:			
Prices and costs	(20,491)	1,514,335	2,551,358
Quantity estimates	436,812	207,955	209,061
Accretion of discount	516,752	327,181	132,097
Future development costs	(796,658)	(493,856)	(344,531)
Income tax	(978,455)	(973,113)	(1,159,368)
Production rates and other	(2,007)	2,372	821
Net revisions	(844,047)	584,874	1,389,438
Extensions, additions and discoveries	1,383,710	1,092,285	619,556
Production	(1,512,036)	(905,910)	(610,064)
Development costs	484,341	434,554	326,219
Purchases in place (b)	2,900,790	1,043,242	557,561
Sales in place (c)	–	(15,802)	(45)
Net change	2,412,758	2,233,243	2,282,665
Standardized measure, December 31	$ 8,402,443 (d)	$ 5,989,685 (e)	$ 3,756,442

(a) The standardized measure has been reduced by estimated operated overhead expense, resulting in a restatement from previously reported amounts of the standardized measure at December 31, 2003 and 2002, and of the changes in the standardized measure for 2003 and 2002.

(b) Generally based on the year-end present value (at year-end prices and costs) plus the cash flow received from such properties during the year, rather than the estimated present value at the date of acquisition.

(c) Generally based on beginning of the year present value (at beginning of year prices and costs) less the cash flow received from such properties during the year, rather than the estimated present value at the date of sale.

(d) The December 31, 2004 standardized measure includes a reduction of $14.6 million ($22.9 million before income tax) for estimated property abandonment costs. The consolidated balance sheet at December 31, 2004 includes a long-term liability of $159.9 million for the same asset retirement obligation, which was calculated using different cost and present value assumptions as required by SFAS No. 143.

(e) The December 31, 2003 standardized measure includes a reduction of $7 million ($10.8 million before income tax) for estimated property abandonment costs. The consolidated balance sheet at December 31, 2003 includes a long-term liability of $93.4 million for the same asset retirement obligation, which was calculated using different cost and present value assumptions as required by SFAS No. 143.

Price and cost revisions are primarily the net result of changes in year-end prices, based on beginning of year reserve estimates. Quantity estimate revisions are primarily the result of the extended economic life of proved reserves and proved undeveloped reserve additions attributable to increased development activity.

Year-end average realized gas prices used in the estimation of proved reserves and calculation of the standardized measure were $5.69 for 2004, $5.71 for 2003, $4.41 for 2002 and $2.36 for 2001. Year-end average realized natural gas liquids prices were $28.24 for 2004, $23.17 for 2003, $17.86 for 2002 and $8.70 for 2001. Year-end average realized oil prices were $41.03 for 2004, $30.55 for 2003, $29.69 for 2002 and $17.39 for 2001. Proved oil and gas reserves at December 31, 2004 include 192,719,000 Mcf of gas and 1,647,000 Bbls of oil and discounted present value before income tax of $403.4 million related to our ownership of approximately 54% of Hugoton Royalty Trust units at December 31, 2004.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934, as amended). Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2004. In making this assessment, our management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") in Internal Control-Integrated Framework. Our management has concluded that, based on these criteria, we have maintained in all material respects, effective internal control over financial reporting as of December 31, 2004. Our independent registered public accounting firm, KPMG LLP, has issued an audit report on our assessment of our internal control over financial reporting, which is included herein.

Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls and procedures or our internal controls will prevent all error and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within our Company have been detected.

March 7, 2005

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of XTO Energy Inc.:

We have audited the accompanying consolidated balance sheets of XTO Energy Inc. and its subsidiaries as of December 31, 2004 and 2003, and the related consolidated income statements, statements of cash flows and statements of stockholders' equity for each of the years in the three-year period ended December 31, 2004. In connection with our audits of the consolidated financial statements, we also have audited the related financial statement schedules. These consolidated financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedules 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 financial position of XTO Energy Inc. and its subsidiaries as of December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2004, in conformity with U.S. generally accepted accounting principles. Also in our opinion, the related financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

As discussed in Note 1 to the consolidated financial statements, the Company changed its method of accounting for asset retirement obligations effective January 1, 2003, in connection with its adoption of Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of XTO Energy Inc.'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 (COSO), and our report dated March 7, 2005 expressed an unqualified opinion on management's assessment of, and the effective operation of, internal control over financial reporting.

KPMG LLP

Dallas, Texas
March 7, 2005

To the Board of Directors and Shareholders of XTO Energy Inc.:

We have audited management's assessment, included in Management's Report on Internal Control over Financial Reporting, that XTO Energy Inc. 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 (COSO). XTO Energy Inc.'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 XTO Energy Inc. maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Also, in our opinion, XTO Energy Inc. maintained, in all material respects, 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 (COSO).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of XTO Energy Inc. and its subsidiaries as of December 31, 2004 and 2003, and the related consolidated income statements, statements of cash flows and statements of stockholders' equity for each of the years in the three-year period ended December 31, 2004, and our report dated March 7, 2005 expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP

Dallas, Texas
March 7, 2005

XTO ENERGY INC. CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS

SCHEDULE II

(IN THOUSANDS)	BALANCE AT BEGINNING OF PERIOD	ADDITIONS (a)	DEDUCTIONS (b)	OTHER	BALANCE AT END OF PERIOD
Year Ended December 31, 2004					
Allowance for doubtful accounts -					
Joint interest and other receivables	$ 6,328	$ 232	$ (535)	$(2,161)(c)	$ 3,864
Year Ended December 31, 2003					
Allowance for doubtful accounts -					
Joint interest and other receivables	$ 5,537	$1,319	$ (528)	$ –	$ 6,328
Year Ended December 31, 2002					
Allowance for doubtful accounts -					
Joint interest and other receivables	$ 4,098	$ 980	$ (65)	$ 524(d)	$ 5,537

(a) Additions relate to provisions for doubtful accounts.

(b) Deductions relate to the write-off of accounts receivable deemed uncollectible.

(c) Reduction based on collection experience.

(d) Adjustment related to reclassified account balances.

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on the 7th day of March 2005.

XTO ENERGY INC.

By BOB R. SIMPSON

Bob R. Simpson, Chairman of the Board
and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on the 7th day of March 2005.

Principal Executive Officers (and Directors)

BOB R. SIMPSON

Bob R. Simpson, Chairman of the Board
and Chief Executive Officer

STEFFEN E. PALKO

Steffen E. Palko, Vice Chairman of the Board
and President

Directors

WILLIAM H. ADAMS III

William H. Adams III

PHILLIP R. KEVIL

Phillip R. Kevil

JACK P. RANDALL

Jack P. Randall

SCOTT G. SHERMAN

Scott G. Sherman

HERBERT D. SIMONS

Herbert D. Simons

Principal Financial Officer

LOUIS G. BALDWIN

Louis G. Baldwin, Executive Vice President
and Chief Financial Officer

Principal Accounting Officer

BENNIE G. KNIFFEN

Bennie G. Kniffen, Senior Vice President
and Controller

Documents filed prior to June 1, 2001 were filed with the Securities and Exchange Commission under our prior name, Cross Timbers Oil Company.

Exhibit No.	Description
2.1 +	Asset Sale Agreement between Chevron U.S.A. Inc. as Seller and XTO Energy Inc. as Buyer, dated May 14, 2004 (incorporated by reference to Exhibit 2.1 to Form 8-K filed August 19, 2004)
2.2 +	Agreement and Plan of Merger by and among Antero Resources Corporation, XTO Energy Inc. and XTO Barnett Inc., dated January 9, 2005
2.3 +	Amendment to Agreement and Plan of Merger by and among Antero Resources Corporation, XTO Energy Inc. and XTO Barnett Inc., dated February 3, 2005
3.1	Restated Certificate of Incorporation of the Company, as restated on June 21, 2004 (incorporated by reference to Exhibit 3.1 to Form 10-Q for the quarter ended June 30, 2004)
3.2	Amended Bylaws of the Company (incorporated by reference to Form 10-K for the year ended December 31, 2003)
4.1	Form of Indenture for Senior Debt Securities dated as of April 23, 2002 between the Company and the Bank of New York, as Trustee (incorporated by reference to Exhibit 4.3.1 to Form 8-K filed April 17, 2002)
4.2	First Supplemental Indenture dated as of April 23, 2002, between the Company and the Bank of New York, as Trustee for the 7½% Senior Notes due April 15, 2012 (incorporated by reference to Exhibit 4.2 to Form 10-K for the year ended December 31, 2002)
4.3	Preferred Stock Purchase Rights Agreement between the Company and ChaseMellon Shareholder Services, LLC (incorporated by reference to Exhibit 4.1 to Form 8-A/A filed September 8, 1998)
4.4	Certificate of Designation of Series A Junior Participating Preferred Stock, par value $0.01 per share, dated August 25, 1998 (incorporated by reference to Exhibit 4.1 to Form 10-Q for the quarter ended September 30, 2000)
4.5	Registration Rights Agreement among the Company and partners of Cross Timbers Oil Company, L.P. (incorporated by reference to Exhibit 10.9 to Registration Statement on Form S-1, File No. 33-59820)
4.6	Indenture dated as of April 23, 2003, between the Company and the Bank of New York, as Trustee for the 6¼% Senior Notes due April 15, 2013 (incorporated by reference to Exhibit 4.1 to Form 10-Q for the quarter ended March 31, 2003)
4.7	Registration Rights Agreement dated April 23, 2003, between the Company and certain Initial Purchasers named therein (incorporated by reference to Exhibit 4.2 to Form 10-Q for the quarter ended March 31, 2003)
4.8	Indenture for Senior Debt Securities dated as of January 22, 2004, between the Company and the Bank of New York, as Trustee (incorporated by reference to Exhibit 4.3.1 to Form 8-K filed January 16, 2004)
4.9	First Supplemental Indenture dated as of January 22, 2004, between the Company and the Bank of New York for the 4.9% Senior Notes due February 1, 2014 (incorporated by reference to Exhibit 4.3.2 to Form 8-K filed January 16, 2004)
4.10	Indenture dated as of September 23, 2004, between the Company and the Bank of New York, as Trustee for the 5% Senior Notes due 2015 (incorporated by reference to Exhibit 4.1 to Form 8-K filed September 20, 2004)
10.1 *	Amended and Restated Employment Agreement between the Company and Bob R. Simpson, dated May 17, 2000 (incorporated by reference to Exhibit 10.2 to Form 10-Q for the quarter ended June 30, 2000)
10.2 *	Amendment to Amended and Restated Employment Agreement between the Company and Bob R. Simpson, dated August 20, 2002 (incorporated by reference to Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 2002)
10.3 *	Amended and Restated Employment Agreement between the Company and Steffen E. Palko, dated May 17, 2000 (incorporated by reference to Exhibit 10.3 to Form 10-Q for the quarter ended June 30, 2000)
10.4 *	Amendment to Amended and Restated Employment Agreement between the Company and Steffen E. Palko, dated August 20, 2002 (incorporated by reference to Exhibit 10.2 to Form 10-Q for the quarter ended September 30, 2002)

10.5 *	1998 Stock Incentive Plan, as amended March 17, 2004 (incorporated by reference to Exhibit 10.1 to Form 10-Q for the quarter ended March 31, 2004)
10.6 *	2004 Stock Incentive Plan (incorporated by reference to Appendix A to the Proxy Statement dated October 15, 2004 for the Special Meeting of Stockholders held November 16, 2004)
10.7 *	Form of Nonqualified Stock Option Agreement for Employees under the 2004 Stock Incentive Plan (incorporated by reference to Exhibit 10.2 to Form 8-K filed November 22, 2004)
10.8 *	Form of Stock Award Agreement for Employees under the 2004 Stock Incentive Plan (incorporated by reference to Exhibit 10.3 to Form 8-K filed November 22, 2004)
10.9 *	Form of Nonqualified Stock Option Agreement for Non-Employee Directors under the 2004 Stock Incentive Plan (incorporated by reference to Exhibit 10.4 to Form 8-K filed November 22, 2004)
10.10 *	Form of Stock Award Agreement for Non-Employee Directors under the 2004 Stock Incentive Plan (incorporated by reference to Exhibit 10.5 to Form 8-K filed November 22, 2004)
10.11 *	Form of Stock Grant Agreement for Non-Employee Directors under Section 11 of the 2004 Stock Incentive Plan (incorporated by reference to Exhibit 10.1 to Form 8-K filed February 22, 2005)
10.12 *	Amended Employee Severance Protection Plan, as amended February 15, 2000 (incorporated by reference to Exhibit 10.14 to Form 10-K for the year ended December 31, 1999)
10.13 *	Amendment to Amended Employee Severance Protection Plan, as amended August 20, 2002 (incorporated by reference to Exhibit 10.5 to Form 10-Q for the quarter ended September 30, 2002)
10.14 *	Amended and Restated Management Group Employee Severance Protection Plan, as amended February 15, 2000 (incorporated by reference to Exhibit 10.13 to Form 10-K for the year ended December 31, 1999)
10.15 *	Amendment to Amended and Restated Management Group Employee Severance Protection Plan, as amended August 20, 2002 (incorporated by reference to Exhibit 10.4 to Form 10-Q for the quarter ended September 30, 2002)
10.16 *	Outside Directors Severance Plan, dated August 20, 2002 (incorporated by reference to Exhibit 10.6 to Form 10-Q for the quarter ended September 30, 2002)
10.17 *	Form of Agreement for Grant of Performance Shares (relating to change in control) between the Company and each of Bob R. Simpson and Steffen E. Palko dated February 20, 2001 (incorporated by reference to Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 2001)
10.18 *	Form of Agreement for Grant of Performance Shares (relating to change in control) between the Company and each of Louis G. Baldwin, Keith A. Hutton and Vaughn O. Vennerberg II dated February 20, 2001 (incorporated by reference to Exhibit 10.2 to Form 10-Q for the quarter ended September 30, 2001)
10.19 *	Amendment to Agreement for Grant of Performance Shares (relating to change in control) between the Company and Bob R. Simpson dated May 24, 2001 (incorporated by reference to Exhibit 10.3 to Form 10-Q for the quarter ended September 30, 2001)
10.20 *	Amendment to Agreement for Grant of Performance Shares (relating to change in control) between the Company and Steffen E. Palko dated May 24, 2001 (incorporated by reference to Exhibit 10.4 to Form 10-Q for the quarter ended September 30, 2001)
10.21 *	Amendment to Agreement for Grant of Performance Shares (relating to change in control) between the Company and Louis G. Baldwin dated May 24, 2001 (incorporated by reference to Exhibit 10.5 to Form 10-Q for the quarter ended September 30, 2001)
10.22 *	Amendment to Agreement for Grant of Performance Shares (relating to change in control) between the Company and Keith A. Hutton dated May 24, 2001 (incorporated by reference to Exhibit 10.6 to Form 10-Q for the quarter ended September 30, 2001)
10.23 *	Amendment to Agreement for Grant of Performance Shares (relating to change in control) between the Company and Vaughn O. Vennerberg II dated May 24, 2001 (incorporated by reference to Exhibit 10.7 to Form 10-Q for the quarter ended September 30, 2001)
10.24 *	Form of Amended and Restated Agreement for Grant (relating to change in control) between the Company and Bob R. Simpson, Steffen E. Palko, Louis G. Baldwin, Keith A. Hutton and Vaughn O. Vennerberg II, dated October 15, 2004 (incorporated by reference to Exhibit 10.1 to Form 8-K filed October 21, 2004)

10.25 * Phantom Performance Share Award Agreement between the Company and Bob R. Simpson, dated April 23, 2004 (incorporated by reference to Form 10-Q for the quarter ended June 30, 2004)

10.26 * Phantom Performance Share Award Agreement between the Company and Bob R. Simpson, dated June 18, 2004 (incorporated by referenced to Form 10-Q for the quarter ended June 30, 2004)

10.27 * Form of Agreement for Grant of Phantom Performance Shares between the Company and each of Bob R. Simpson, Steffen E. Palko, Louis G. Baldwin, Keith A. Hutton and Vaughn O. Vennerberg II, dated June 24, 2004 (incorporated by referenced to Form 10-Q for the quarter ended June 30, 2004)

10.28 * Form of Agreement for Grant of Phantom Performance Shares between the Company and each of Bob R. Simpson, Steffen E. Palko, Louis G. Baldwin, Keith A. Hutton and Vaughn O. Vennerberg II, dated July 8, 2004 (incorporated by referenced to Form 10-Q for the quarter ended June 30, 2004)

10.29 Five-Year Revolving Credit Agreement dated February 17, 2004, between the Company and certain commercial banks named therein (incorporated by reference to Exhibit 10.18 to Form 10-K for the year ended December 31, 2003)

10.30 Term Loan Credit Agreement dated November 10, 2004 between the Company and certain commercial banks named therein (incorporated by reference to Exhibit 10.20 to Form S-4 dated December 13, 2004)

12.1 Computation of Ratio of Earnings to Fixed Charges

21.1 Subsidiaries of XTO Energy Inc.

23.1 Consent of KPMG LLP

23.3 Consent of Miller and Lents, Ltd.

31 Rule 13a-14(a)/15d-14(a) Certifications

- 31.1 Chief Executive Officer Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
- 31.2 Chief Financial Officer Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

32 Section 1350 Certifications

- 32.1 Chief Executive Officer and Chief Financial Officer Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

+ All schedules and similar attachments have been omitted. The Company agrees to furnish supplementally a copy of the omitted schedules and similar attachments to the Securities and Exchange Commission upon request.

* Management contract or compensatory plan

Copies of the above exhibits not contained herein are available, at the cost of reproduction, to any security holder upon written request to the Secretary, XTO Energy Inc., 810 Houston Street, Fort Worth, Texas 76102.

DIRECTORS

BOB R. SIMPSON
Chairman and
Chief Executive Officer
XTO Energy Inc.

STEFFEN E. PALKO
Vice Chairman and President
XTO Energy Inc.

WILLIAM H. ADAMS III (a, b, c)
President
Texas Bank
Fort Worth Downtown

PHILLIP R. KEVIL (a)
Retired Executive
Certified Public Accountant

JACK P. RANDALL
Cofounder
Randall & Dewey
Division of Jefferies & Company, Inc.

SCOTT G. SHERMAN (a, b, c)
Owner
Sherman Enterprises

HERBERT D. SIMONS (a, b, c)
Counsel
Winstead Sechrest & Minick P.C.

ADVISORY DIRECTORS

LOUIS G. BALDWIN
Executive Vice President and
Chief Financial Officer
XTO Energy Inc.

DR. LANE G. COLLINS (a, b, c)
Professor of Accounting
Baylor University

KEITH A. HUTTON
Executive Vice President,
Operations
XTO Energy Inc.

VAUGHN O. VENNERBERG II
Executive Vice President,
Administration
XTO Energy Inc.

a) Audit Committee
b) Compensation Committee
c) Corporate Governance and Nominating Committee

EXECUTIVE OFFICERS

BOB R. SIMPSON
Chairman and
Chief Executive Officer

STEFFEN E. PALKO
Vice Chairman and President

LOUIS G. BALDWIN
Executive Vice President and
Chief Financial Officer

KEITH A. HUTTON
Executive Vice President,
Operations

VAUGHN O. VENNERBERG II
Executive Vice President,
Administration

SENIOR OFFICERS

NICK J. DUNGEY
Senior Vice President,
Natural Gas Operations

KEN K. KIRBY
Senior Vice President, Operations
Eastern Region

BENNIE G. KNIFFEN
Senior Vice President and
Controller

TIMOTHY L. PETRUS
Senior Vice President,
Acquisitions

EDWIN S. RYAN, JR.
Senior Vice President,
Land

TERRY L. SCHULTZ
Senior Vice President,
Marketing

DOUGLAS C. SCHULTZE
Senior Vice President, Operations
Mid-Continent

GARY D. SIMPSON
Senior Vice President,
Investor Relations & Finance

KENNETH F. STAAB
Senior Vice President, Engineering

OTHER OFFICERS

VIRGINIA N. ANDERSON
Vice President and
Corporate Secretary

BRENT W. CLUM
Vice President and Treasurer

DELBERT L. CRADDOCK
Vice President, Operations
San Juan Basin

JAMES L. DEATH
Vice President, Land

KYLE M. HAMMOND
Vice President, Operations
Permian Division

NINA C. HUTTON
Vice President, Environmental,
Health and Safety

FRANK G. MCDONALD
Vice President, General Counsel
and Assistant Secretary

TIMOTHY B. MCILWAIN
Vice President, Operations
Fort Worth Division

ROBERT C. MYERS
Vice President,
Human Resources

F. TERRY PERKINS, JR.
Vice President,
Reservoir Engineering

MARK J. POSPISIL
Vice President,
Geology & Geophysics

MARK A. STEVENS
Vice President,
Taxation

E. E. STORM III
Vice President and General
Counsel, Land & Acquisitions

L. FRANK THOMAS III
Vice President,
Information Technology

MICHAEL R. TYSON
Vice President,
Financial Reporting

T. JOY WEBSTER
Vice President, Facilities

KATHY L. COX
Associate General Counsel and
Assistant Secretary

ROBERT B. GATHRIGHT
Assistant Controller and
Director of Budget & Planning

Corporate Headquarters

810 Houston Street
Fort Worth, Texas 76102
(817) 870-2800

Operations Offices

Eastern Region

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6141 Paluxy Drive
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(903) 939-1200

San Juan & Raton

2700 Farmington Avenue
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Farmington, New Mexico 87401
(505) 324-1090

Arkoma

P.O. Box 218
1541 Airport Road
Ozark, Arkansas 72949
(479) 667-4819

Permian

200 N. Loraine, Suite 800
Midland, Texas 79701
(915) 682-8873

Mid-Continent

210 Park Avenue, Suite 2350
Oklahoma City, Oklahoma 73102
(405) 232-4011

Fort Worth Basin

210 West 6th Street
Fort Worth, Texas 76102
(817) 810-0402

Alaska

52260 Shell Road
Kenai, Alaska 99611
(907) 776-2511

Annual Meeting

Tuesday, May 17, 2005 at 10 a.m.
Fort Worth Club Tower
777 Taylor Street
12th Floor, Horizon Room
Fort Worth, Texas

Independent Auditors

KPMG LLP
Dallas, Texas

Senior Notes

7.50% Notes due 2012
CUSIP# 98385XAA4

6.25% Notes due 2013
CUSIP# 98385XAB2

4.90% Notes due 2014
CUSIP# 98385XAD8

5.0% Notes due 2015
CUSIP# 98385XAE6

Transfer Agents *and* Registrars

Common Stock:

Mellon Investor Services LLC
Overpeck Center
85 Challenger Road
Ridgefield Park, New Jersey
07660-2108
www.mellon-investor.com/isd

Senior Notes:

Bank of New York
Corporate Trust Division
New York, New York

Form 10-K

Additional copies of the Company's Annual Report on Form 10-K filed with the Securities and Exchange Commission may be obtained, without charge, upon request to Investor Relations at our corporate address and are also available free of charge on the Company's web site at www.xtoenergy.com. Copies of any exhibits to the Company's Annual Report on Form 10-K may also be obtained, without charge, upon specific request.

Direct Stock Purchase/Dividend Reinvestment Plan

A Direct Stock Purchase and Dividend Reinvestment Plan allows new investors to buy XTO Energy common stock for as little as $500 and existing shareholders to automatically reinvest dividends. For more information, request a prospectus from: Mellon Investor Services LLC at (800) 938-6387.

Shareholder Services

For questions about dividend checks, electronic payment of dividends, stock certificates, address changes, account balances, transfer procedures and year-end tax information call (888) 877-2892.

Web Site

www.xtoenergy.com

Certifications

The certifications of the Chief Executive Officer and Chief Financial Officer of XTO Energy required by Section 302 of the Sarbanes-Oxley Act of 2002 have been filed as Exhibits 31.1 and 31.2, respectively, to the Company's Form 10-K for the fiscal year ended December 31, 2004.

As required by the New York Stock Exchange (NYSE) listing standards, an unqualified annual certification indicating compliance with the corporate governance listing standards was signed by the Company's Chief Executive Officer and submitted to the NYSE on May 26, 2004.

XTO Energy Inc. is a natural gas and oil producer engaged in the acquisition and development of long-lived, high-quality producing properties across the United States. The Company, established in 1986 as Cross Timbers Oil Company, operates more than 88% of the value of its properties, encompassing ownership in about 18,000 oil and gas wells. Operations are in Texas, New Mexico, Arkansas, Oklahoma, Kansas, Louisiana, Colorado, Wyoming, Utah and Alaska. Headquarters are located in Fort Worth, Texas and at year end, the Company had 1,356 employees.

As of December 31, 2004, the Company owns 5.86 Tcfe of proved reserves of which 72% are proved developed. Gas volumes account for 80% of total reserves. Under SEC guidelines, the present value before income tax, discounted at 10%, of the Company's proved reserves equals $12.2 billion. Reserves are engineered each year by the independent engineering firm, Miller & Lents, Ltd.

Since going public in 1993, XTO has grown total daily production and proved reserves at compound annual rates of 24% and 31%, respectively. Over the same period, its stock price has increased from $13 to about $300 per share, excluding adjustments for stock splits. The Company has also created two other publicly traded investments: Cross Timbers Royalty Trust (NYSE:CRT) and Hugoton Royalty Trust (NYSE:HGT) which went public in 1992 and 1999, respectively.

[illegible] Report, other than historical financial information, contains forward-looking statements regarding results of future [illegible] expenditures, growth in production, growth in reserves, cash margins, operating cash flow and operating cash flow [illegible] reserves, unbooked reserve potential, availability of properties for strategic acquisitions, profitability, percentage [illegible] expected to maintain production rates, economic returns, rate of return on capital, industry performance, industry [illegible] drilling and development costs, revenues, drilling success rates, inventory and drilling locations, availability of oil and [illegible] supply, demand for oil and natural gas, future stock performance, oil and natural gas prices and other matters subject [illegible] risks and uncertainties that are detailed in the Company's Annual Report on Form 10-K for the year ended [illegible] 2004, which is incorporated by this reference as though fully set forth herein. Although the Company believes that [illegible] reflected in such statements are reasonable based on current available information, there is no assurance that [illegible] projections can or will be met.

[illegible] Exchange Commission has generally permitted oil and gas companies, in their filings made with the SEC, to [illegible] reserves that a company has demonstrated by actual production or conclusive formation test to be economically [illegible] producible under existing economic and operating conditions. We use the terms reserve "potential" or "upside" or [illegible] of volumes of reserves potentially recoverable through additional drilling or recovery techniques that the SEC's [illegible] include in filings with the SEC. These estimates are by their nature more speculative than estimates [illegible] and accordingly are subject to substantially greater risk of being actually realized by the Company.

AT XTO ENERGY, OUR PROVEN STRATEGY ENDURES TODAY. WE ACQUIRE QUALITY PRODUCING PROPERTIES RICH WITH HYDROCARBONS, ENGAGE A RIGOROUS GEOSCIENCE PROCESS TO DISCOVER NEW RESERVES, DELIVER CONSISTENT RESULTS AND PLAN AHEAD FOR MORE OF THE SAME.