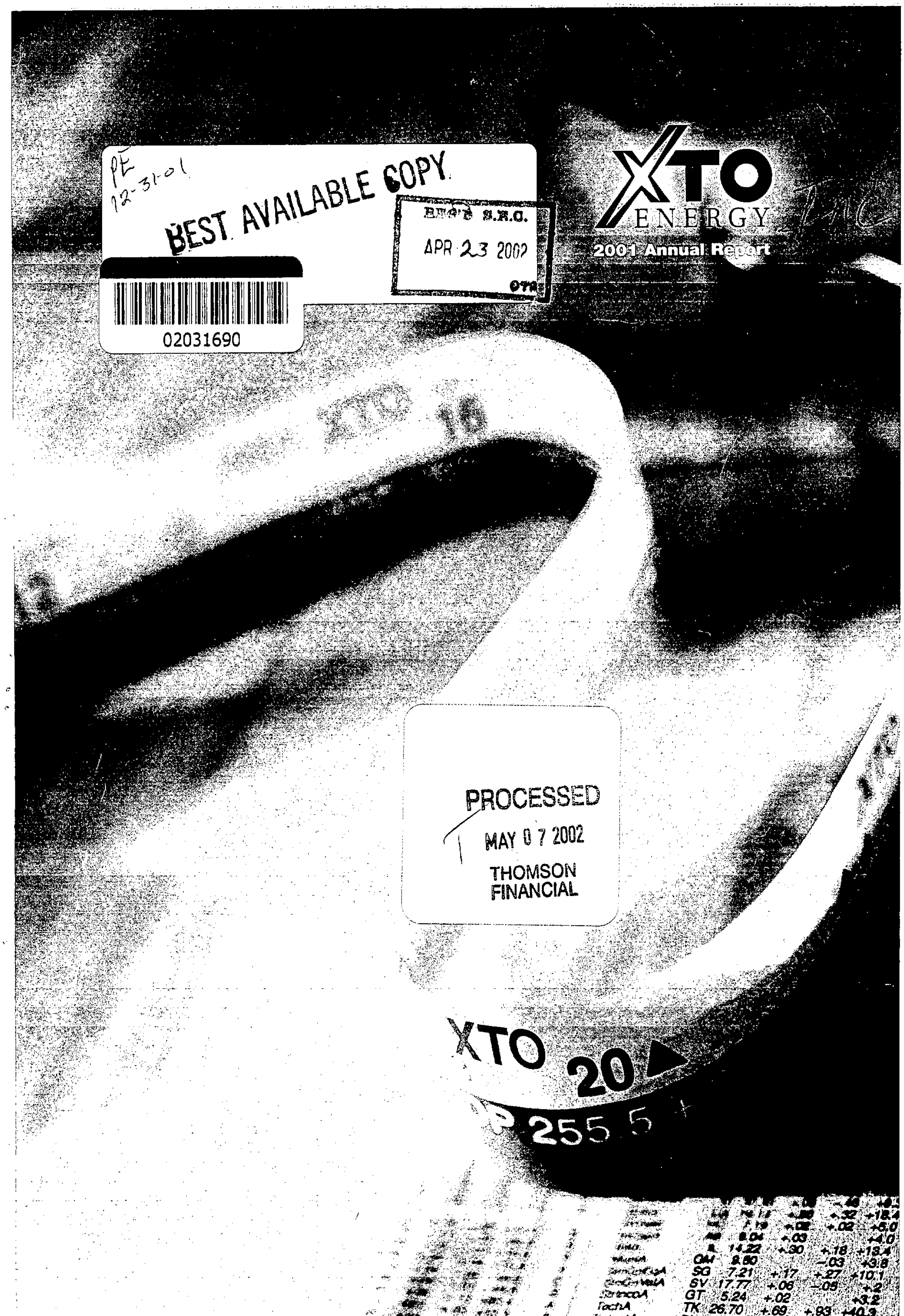
XTO ENERGY

2001 Annual Report



For any business, success is grounded in a solid strategy.

For fifteen years, XTO Energy has followed a "tried-and-true" process in building its energy franchise. The Company targets only the highest quality properties in legacy basins to acquire and develop. We apply rigorous geoscience discipline and employ operational innovation. We grow our production. We grow our reserves. We deliver healthy economic returns.

Then...we repeat.

SUCCESS

Company Profile

XTO Energy Inc., established in 1986 as Cross Timbers Oil Company, is a premier domestic natural gas and oil producer engaged in the acquisition and development of high-quality legacy properties. The Company operates more than 94% of the value of its producing properties, which encompass more than 7,300 oil and gas wells. These properties are concentrated in Texas, Arkansas, Oklahoma, Kansas, New Mexico, Wyoming, Louisiana and Alaska.

Since going public in 1993 at $13.00 per share, the Company's stock price has increased more than seven times to the equivalent of about $100, after adjustments for four three-for-two stock splits. Over the past five years, XTO Energy led its peers in total investor returns with a 29.5% compound annual appreciation.*

To date, the Company has grown its proved reserves at a compound annual rate of 32% to more than 2.68 Tcfe. Over the same period, total equivalent daily production has increased from an initial yearly average of 93 MMcfe to 525 MMcfe, an annual compounded gain of 24%.

XTO Energy is listed on the New York Stock Exchange under the symbol "XTO." The Company also created two other publicly traded investments: Cross Timbers Royalty Trust ("CRT" traded on the NYSE) and Hugoton Royalty Trust ("HGT" traded on the NYSE), which went public in 1992 and 1999, respectively.

XTO Energy is headquartered in Fort Worth, Texas. At year-end 2001, the Company had 742 employees.

* *Wall Street Journal*, February 25, 2002, "Annual Shareholder Scoreboard," p. B11.

OK

Financial Highlights

In thousands except production, per share and per unit data	2001	2000	1999
FINANCIAL			
Total revenues	$ 838,748	$ 600,851	$ 341,295
Income before income tax, minority interest and cumulative effect of accounting change	$ 455,357 (a)	$ 176,432 (b)	$ 70,605 (c)
Income before cumulative effect of accounting change	$ 293,405 (a)	$ 116,993 (b)	$ 46,743 (c)
Earnings available to common stock	$ 248,816 (a)(d)	$ 115,235 (b)	$ 44,964 (c)
Per common share (e)			
Basic	$ 2.03 (f)	$ 1.08	$ 0.43
Diluted	$ 2.00 (f)	$ 1.03	$ 0.42
Operating cash flow (g)	$ 549,567	$ 344,638	$ 132,683
Operating cash flow per share (e)	$ 4.49	$ 3.23	$ 1.26
Total assets	$ 2,132,327	$ 1,591,904	$ 1,477,081
Long-term debt			
Senior	$ 556,000	$ 469,000	$ 684,100
Subordinated notes and other	$ 300,000	$ 300,000	$ 307,000
Total stockholders' equity	$ 821,050	$ 497,367	$ 277,817
Common shares outstanding at year-end (e)	123,773	116,334	110,001
PRODUCTION			
Daily production			
Oil (Bbls)	13,637	12,941	14,006
Gas (Mcf)	416,927	343,871	288,000
Natural gas liquids (Bbls)	4,385	4,430	3,631
Mcfe	525,062	448,098	393,826
Average price			
Oil (per Bbl)	$ 23.49	$ 27.07	$ 16.94
Gas (per Mcf)	$ 4.51	$ 3.38	$ 2.13
Natural gas liquids (per Bbl)	$ 15.41	$ 19.61	$ 11.80
PROVED RESERVES			
Oil (Bbls)	54,049	58,445	61,603
Gas (Mcf)	2,235,478	1,769,683	1,545,623
Natural gas liquids (Bbls)	20,299	22,012	17,902
Mcfe	2,681,566	2,252,425	2,022,653
STOCK PRICE			
High	$ 21.45	$ 18.88	$ 6.61
Low	$ 12.40	$ 3.39	$ 2.17
Close	$ 17.50	$ 18.50	$ 4.03
Cash dividends per share	$ .037	$ .022	$ .018
Average daily trading volume	986,007	827,845	436,106

(a) Includes effect of pre-tax derivative fair value gain of $54.4 million and pre-tax non-cash incentive compensation of $9.6 million.

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

(c) Includes effect of a $40.6 million pre-tax gain on sale of Hugoton Royalty Trust units.

(d) Includes an after-tax charge of $44.6 million for the cumulative effect of accounting change.

(e) Adjusted for the three-for-two stock splits effected on September 18, 2000 and June 5, 2001.

(f) Before cumulative effect of accounting change, earnings per share were $2.39 basic and $2.35 diluted.

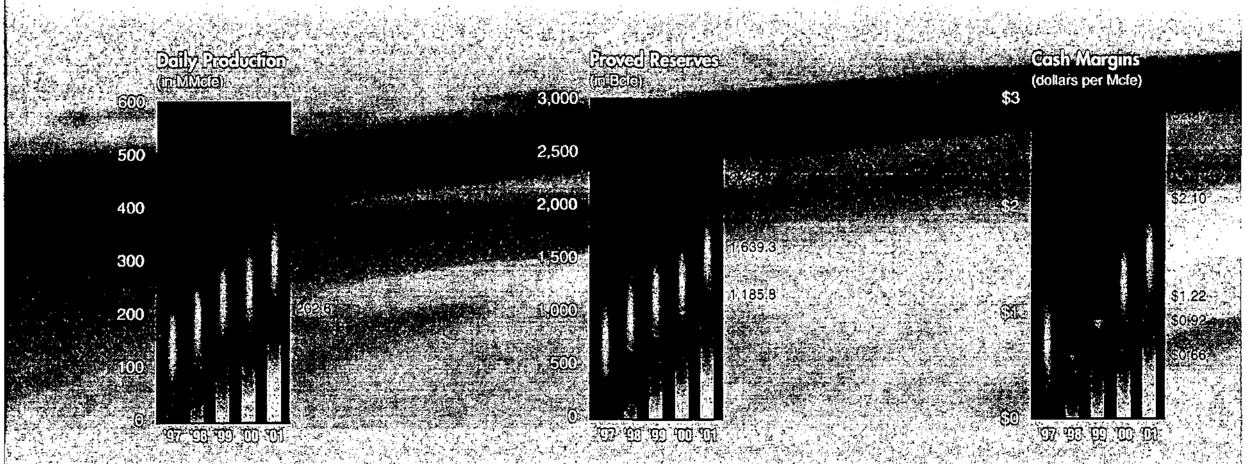
(g) Defined as cash provided by operating activities before changes in operating assets and liabilities and exploration expense.

GLOSSARY

Bbls — *Barrels (of oil or NGLs)*
Bcf — *Billion cubic feet (of gas)*
Bcfe — *Billion cubic feet equivalent*
BOE — *Barrels of oil equivalent*
BOPD — *Barrels of oil per day*
MBO — *Thousand barrels of oil*
Mcf — *Thousand cubic feet (of gas)*
Mcfe — *Thousand cubic feet equivalent*
MMcf — *Million cubic feet (of gas)*
MMcfe — *Million cubic feet equivalent*
NGLs — *Natural gas liquids*
Tcf — *Trillion cubic feet (of gas)*
Tcfe — *Trillion cubic feet equivalent*

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

XTO Energy has emerged as a ***premier producer*** *in the natural gas and oil industry. Our achievements in the past year emphasize our ability to deliver* ***dynamic growth*** *and* ***exceptional financial results.***

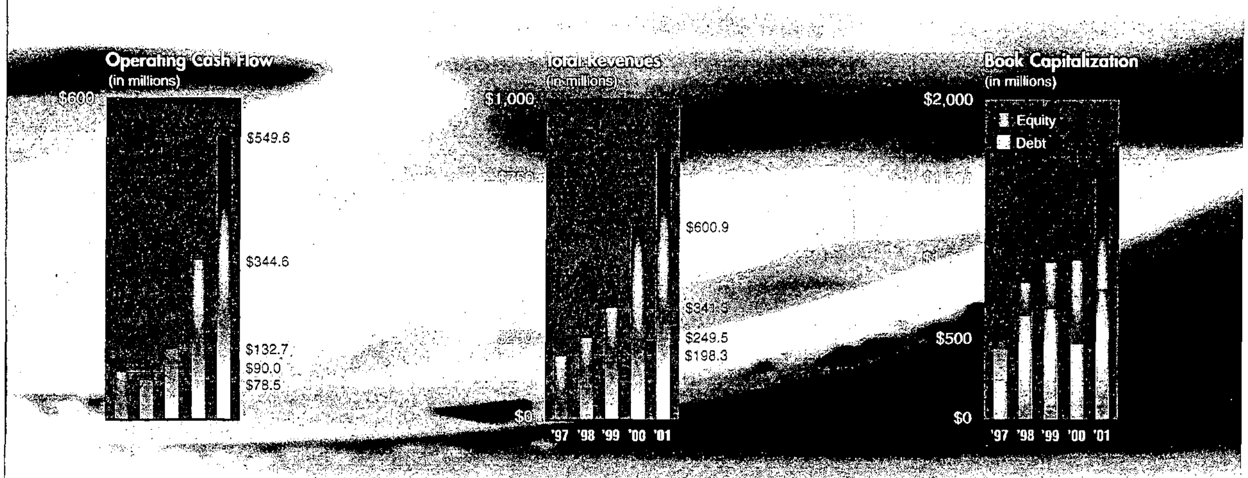


- XTO Energy reported record cash flow from operations of $549.6 million or $4.49 per share, before changes in operating assets and liabilities and exploration expense. These results are up 59% from 2000 cash flow of $344.6 million or $3.23 per share.
- Cash margin grew to $2.87 per Mcfe, an increase of 36% over 2000.
- Year-over-year, XTO Energy increased average daily gas production by 21%, up to 417 MMcf from 344 MMcf.
- XTO Energy replaced 326% of its 2001 production from all sources at a finding cost of $1.01 per Mcfe.
- XTO Energy grew total proved reserves to 2.68 Tcfe from 2.25 Tcfe, up about 19%.

XTO Energy deployed development expenditures of $395 million to drill 285 new wells and perform 425 workovers.

As a result of its ongoing development campaign, XTO Energy now has in excess of 1.5 Tcfe of resource potential for future exploitation, more than 40% of its current proved reserves.

XTO Energy continued to increase its already extensive low-risk drilling inventory by acquiring undeveloped producing properties and leasehold interests in its prolific East Texas Basin.



Over the year, XTO Energy grew equity 65% to $821 million, up from $497 million at year-end 2000.

XTO Energy exited 2001 with a debt-to-book capitalization ratio of 51%, down from the 2000 level of 61%.

Revenues for the year totaled $839 million, a 40% increase from $601 million for 2000.

XTO Energy's market capitalization improved to more than $2 billion with average daily trading volume exceeding 986,007 shares per day, up from 827,845 shares in 2000.

XTO Energy . . .
*a sector **leader** in internal production growth,*
value creation and shareholder returns.

FELLOW SHAREHOLDERS,

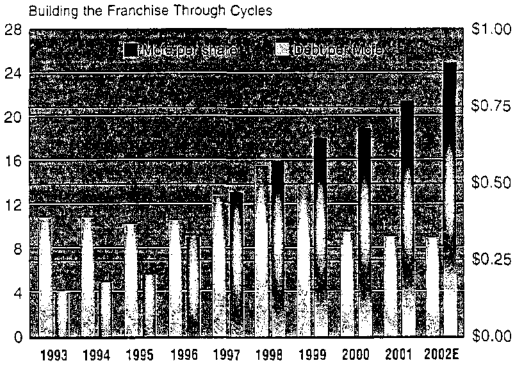
As we entered 2001, an air of excitement surrounded the Company. Our rich inventory of drilling projects was committed to grow natural gas production by 20%. Underlying reserves were projected to increase by more than 15%. The strongest gas prices in decades promised robust economics and a strengthening balance sheet. Altogether, our aspirations for yet another record year were extremely high. We set our goals to match.

Today, we are proud to report that the Company's 2001 performance exceeded our lofty expectations:

- Record cash flow totaled $4.49 per share, besting our $4.00 goal. Operating earnings of $2.16 per share eclipsed the $2.00 target.
- Daily gas production averaged 417 MMcf per day, a 21% increase over the 2000 level, besting our 20% expectation.
- Our proved reserves grew by 19% to 2.68 Tcfe, 83% of which is natural gas. This surpassed our stated goal by 82 Bcfe. Without downward revisions due to lower prices, proved reserves would have been 2.86 Tcfe, up 27%.
- Book equity reached 50% of total capitalization by the end of September, again beating our year-end target date.

Value Creation

Building the Franchise Through Cycles



Equally as important, these achievements fortified XTO's powerful position for future franchise success. The drilling program proved-up new prospects, replenishing inventory to fuel still more organic growth. Strong cash flow allowed for the strategic purchase of undeveloped properties, expanding our high-margin plays. A well-timed hedging program assured excellent financial returns for both 2001 and 2002. Uniquely, XTO Energy has entered the new year with a visible path to exceptional growth and strong investment returns.

Reaching New Heights

Since 1996, the Company has grown from a small-cap niche player in the oil business to a powerhouse natural gas producer. In June 2001, we formally recognized this transition with a corporate name change. All of the tradition, strategic success and proud reputation of "XTO" was joined with "Energy" to reflect the emergence of a $3 billion enterprise focused on natural gas production and rich with years of development opportunities.

XTO Energy's 2.24 Tcf of proved gas reserves ranks us as a top-five owner of domestic natural gas among independents. Our current daily gas production of about 460 MMcf places us *in the top 20 U.S. producers, including majors. Our bountiful* inventory of low-risk, high-margin projects continues to expand. And most importantly, our history of creating value for the shareholder makes us a top-quality investment.

Even as the Company dramatically increased in size, we have stayed true to our conviction to build value per share. Our "Value Creation" graph depicts this success. Since inception, reserves per share are up more than five times as debt per Mcfe of reserves has dropped to historic lows. As a result, each share of XTO stock has steadily grown more valuable with time. This unique success, evident even within a cyclical industry, is attributable to a process that pairs a talented organization with superior properties. We've consistently delivered production and reserve growth throughout commodity cycles — a daunting challenge in a depleting asset business. Performance in 2002 will be no exception as reserves are once again targeted to grow by more than 10% per share.

At XTO Energy, we've always measured our success as an investment with a single metric — value delivered to our owners on a *per share basis*. Simply stated, this means increasing high-quality *reserves per share while ultimately* decreasing the leverage or debt against those reserves.

Since going public in 1993, our success has been impressive. The Company has grown reserves per share more than five times while reducing debt per Mcfe to historic lows. Along with internal value creation, we remain committed to getting that value reflected in the stock price.

REALIZING EXTRAORDINARY VALUE

Fortunately, the momentum is in our favor. Our exceptional financial performance has built confidence on Wall Street. We offer a simple operational story and a visible path for enterprise growth. Our North American natural gas assets are becoming ever more valuable, particularly in light of supply concerns. Combined, the attributes of XTO definitely reflect a top-tier franchise.

So, as we carry forward with stellar performance, our attention is honed on achieving a top market valuation. Ultimately, premium investments will receive premium valuations. We will be working diligently to make that happen.

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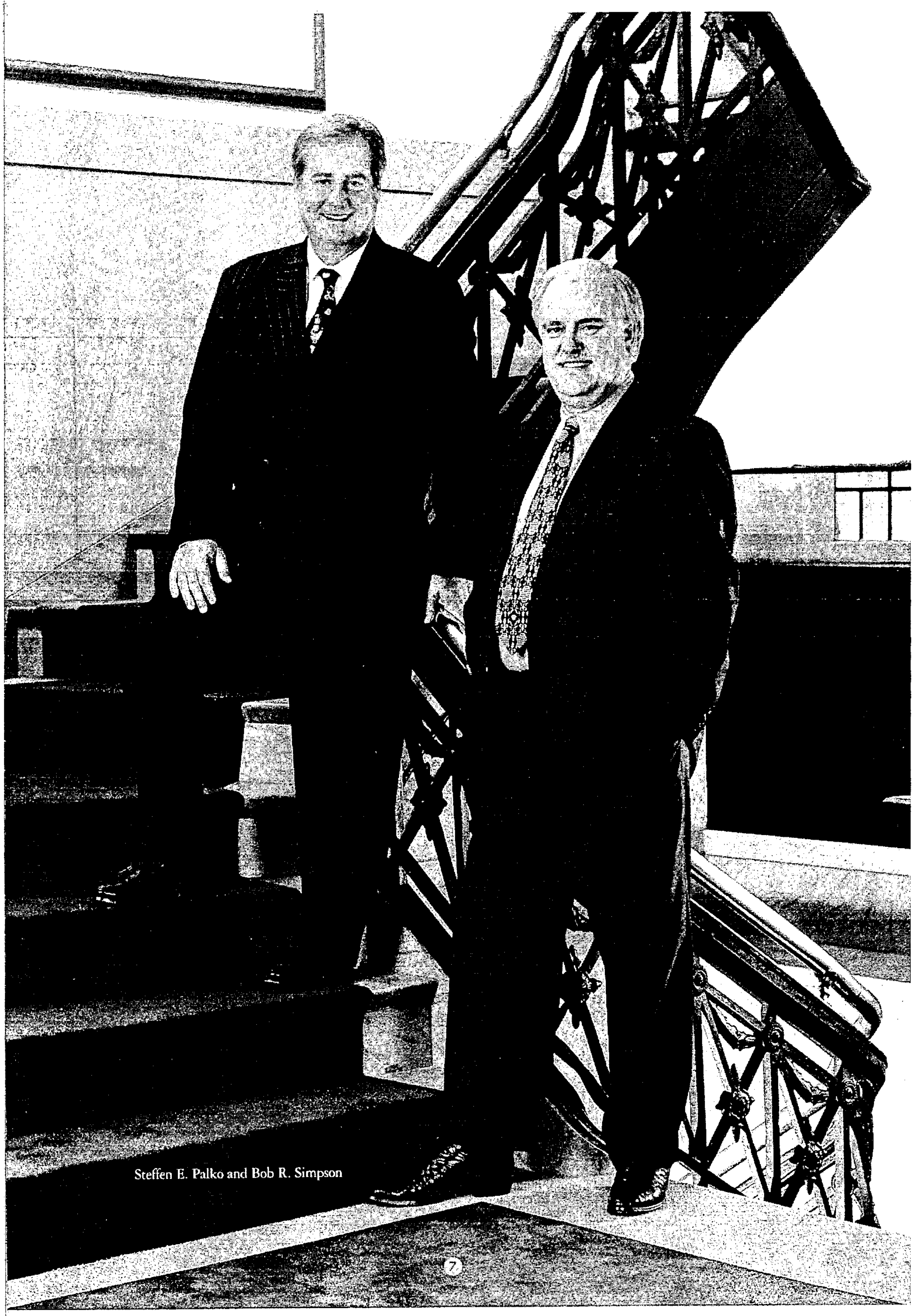


Steffen E. Palko and Bob R. Simpson

Delivering the Results

In 2001, the Company's financial performance made the record books and subsequently garnered XTO broader recognition by investors and analysts.

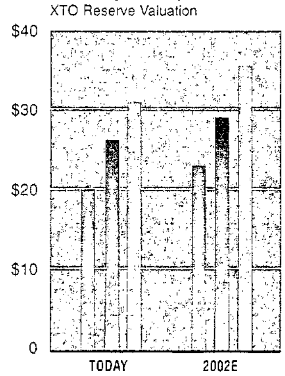
For the year, cash flow from operations hit a record $549.6 million, a 59% increase from $344.6 million for 2000. Excluding the effect of the SFAS No. 133 accounting change for derivatives, gains and losses related to derivative fair value, asset sales and incentive compensation, earnings were $264.5 million or $2.16 per share for 2001, compared with earnings of $140.1 million or $1.31 per share for 2000. The Company reported earnings available to common stock of $248.8 million, or $2.03 per share, compared with earnings of $115.2 million or $1.08 per share for 2000.

Of course, higher production and strong commodity prices also resulted in record revenues. In 2001, revenues totaled $838.7 million, a 40% increase from revenues of $600.9 million for 2000. Operating income for the year was $511 million, a 141% increase from $212.1 million for 2000. We expect to deliver operating cash flow of at least $1 billion over the 2001-2002 period, which is roughly $8 per share to our investors.

Achieving Premium Valuation

Without question, our Company's success has won the confidence of the investment community. The price of XTO stock has increased sevenfold since 1993, delivering a total return of 28% per year. Even so, this value recognition hasn't kept pace with the value created. At today's market price, our stock still trades at a discount to the underlying value of our reserves. However, we believe market momentum is now moving to close this gap.

Realizing Value per Share
XTO Reserve Valuation



☐ $1.25 per Mcfe ▩ $1.50 per Mcfe ☐ $1.75 per Mcfe

In 2001, several peer companies were purchased in a wave of industry consolidation. As a result, the value of hard assets seized the limelight as comparable long-lived, domestic gas properties traded at about $1.50 per Mcfe. For XTO's assets, these sales would reflect a potential stock price of $26 today, moving towards $30 by year-end 2002 as reserves step toward our 3 Tcfe goal. (See our "Realizing Value" graph.) When coupled with projected 17% to 20% gas production growth this year and a strong balance sheet, the case for top-tier valuation is more compelling than ever.

So we are focused on the challenge at hand — realizing the tremendous value we've built. From our perspective, XTO's overall company performance ranks with the best of our peers, those granted the highest market multiples and thus, valuations. By realizing premium valuation, we can deliver a premium stock price to our shareholders.

Forging Ahead

Across the board, our expectations will drive the Company to deliver another year of stellar operational and financial results in 2002. Our goals are clear:

- ☐ Increase natural gas production volumes 17% to 20%
- ☐ Grow proved reserves to 3 Tcfe
- ☐ Generate more than $450 million in cash flow

Our development plan is well underway to "deliver the goods." For the year, we established a budget of $400 million to drill 295 wells and perform 515 workovers. Altogether, we expect to deliver a 3:1 investment efficiency with the deployment of this development capital. Most of these efforts will focus on the high-impact natural gas assets we've acquired since 1996: East Texas, the Arkoma Basin and the San Juan Basin. These three areas collectively represent about 1.5 Tcfe of resource potential to develop and then bring to market. Our exploitation "discovery" in East Texas, the Freestone Trend, has proved a bonanza as new drilling is contributing an average of 2.4 Bcf of net reserves per well. Today, we see 500 to 700 of these highly prolific well locations to drill over the next several years.

Moving forward in 2002, XTO will provide top-tier growth through the drill bit, significant earnings and cash flow, and a strong balance sheet to pursue add-on acquisitions. Hedges for 2002 production assure our exceptional financial performance. With this cash flow certainty, we're continuing our aggressive drilling program at a time when service costs are dropping sharply. The economic impact is significant. For instance, in East Texas this year we will be drilling and completing four new wells for last year's cost of three.

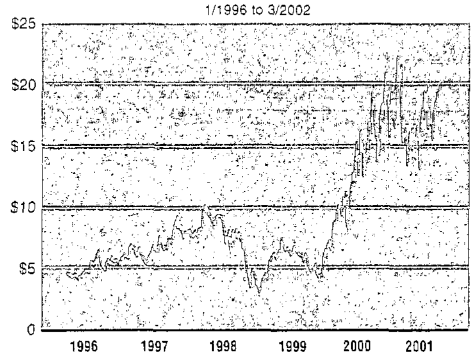
A Balancing Act

Our commitment to natural gas is grounded in its basic fundamentals: supply versus demand. These two factors are caught in a precarious balance. Price volatility over the past 18 months has demonstrated this tug-of-war relationship. From $2 per Mcf to $10 and then back down, this extreme swing tested all aspects of the natural gas business. In our view, the outcome of this erratic cycle is clear: regardless of industry efforts, "lower 48" gas supply is declining.

In 2001, a drilling boom put 1,068 rigs to work looking for new gas reserves. The experts predicted domestic gas production growth of 2% to 4% for the year, yet the tally of reported statistics reveals that production is flat year-over-year, despite these heroic efforts. Indeed, new wells found reserves, but cumulatively the nation's underlying production decline overwhelmed any new production gains. As in 1996, the industry again was unable to deliver growth given its full resources. Producers struggled just to keep production flat. With the current gas rig count now just over 600, we see gas supply diminishing.

We believe this result underscores a long-term change in gas market dynamics: instead of being readily available, domestic gas is *scarce*. As we enter 2002, the impact of this shift has been masked by depressed demand and mild weather. Even so, gas prices have proven historically resilient, testing the bottom and rebounding sharply. Importantly, this strength is not altogether predicated on an expected resurgence in demand; it is also supported by deteriorating supply. As we burn through our current gas surplus and the economy expands, we expect to see a healthy response in natural gas prices. In our assessment, a new price range of $3 to $4 per Mcf is required to just maintain current supply. However, a sustained higher price is needed to meet projected growth for the nation.

Stock Price Performance
1/1996 to 3/2002



Leading the Way

The recent strength in natural gas prices marks the beginning of a new cycle for our business. Our challenge, once again, will be to maximize shareholder returns as we move forward in a volatile environment.

As your management team and fellow shareholders, we are determined to execute our long-term strategy: create value and get it realized. We believe our top-of-class performance has earned confidence with investors and our stock price will ultimately follow suit. Of course, along the way we will be "fine-tuning" our franchise to make it happen.

As always, we appreciate the tremendous dedication of our loyal employees. We also thank our shareholders for your continued support.

Bob R. Simpson
Chairman and Chief Executive Officer

Steffen E. Palko
Vice Chairman and President

March 28, 2002

Our proven process: buy quality assets, employ disciplined exploitation methodology and be consistent in execution.

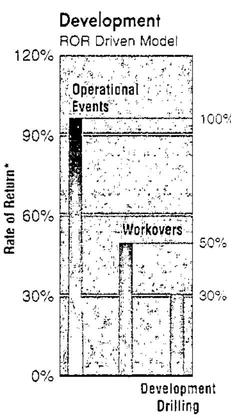
OPERATIONS OVERVIEW

At XTO Energy, we have a straightforward operations directive: make great properties even better. This means that we must find and develop new reserves to create value. To do so, we have devised a development blueprint that delivers superior results.

Our experienced team of "A-level" professionals must rejuvenate the assets we acquire. In application, the team provides operational ingenuity, generates new ideas and involves technical innovation to "manufacture" reserves. To be meaningful, however, this growth must yield attractive economic returns predictably and consistently. Herein lies our strength.

"The right assets are the foundation of a great Company."
– Vaughn O. Vennerberg II
Executive VP, Administration

Our exploitation strategy is grounded in a well-defined economic framework. For each acquisition, we incrementally enhance expected economic returns through three stages of exploitation. As depicted in our "Development" graph, each phase layers targeted "returns on project investment" for capital deployed, ranging from 100% for operational activities to 50% for workovers to a 30% threshold for development wells. When combined with original acquisition economics, we build to a 25% to 30% rate of return (ROR) realization over the life of each asset.



* Assumes $2.50/Mcfe

On a property-by-property basis, we construct this growth model from the bottom up. Each activity is justified by its own economic merit. Cumulatively, these projects form our development portfolio. Today, our Company owns the richest inventory in its history . . . four years of low-risk exploitation projects. Our course is set. We are investing our capital in development programs that deliver not only solid reserve and production growth, but more importantly, solid economic returns.

Development Success

In 2001, XTO Energy invested $395 million to develop 367 Bcfe of high-quality reserves, leading the way to record proved reserves of 2.68 Tcfe. Our highly effective program replaced 191% of production at a cost of $1.08 per Mcfe. Inclusive of our strategic acquisitions, we replaced 326% of production at an all-in finding cost of $1.01 per Mcfe. Importantly, we continue to perform as a sector leader, efficiently finding and developing new reserves. Over the past five years, our capital programs have replaced an average of 439% of production at an all-in cost of $.72 per Mcfe.

Acquisition Efforts

With our ongoing development success, we gain unique knowledge of our core areas. This focused knowledge allows us to generate upside opportunities and "create" acquisition targets. In 2001, we utilized this advantage effectively to expand our inventory of development opportunities.

The Company invested $238 million to purchase 257 Bcfe of reserves in add-on acquisitions, equating to $.93 per Mcfe. Predominantly in East Texas, these properties offer tremendous new reserves in our Freestone Trend, further enhancing our strong growth. The Herd Producing Company properties, along with the Miller Energy interests, could contribute at least 250 additional well sites with net reserve potential of 2.4 Bcf per well in the heart of our East Texas Freestone Trend play. As a result, we expect our development programs to more than double acquired reserves over the next few years.

Key Stat: *XTO has identified 1.5 Tcfe of resource potential for development over the next several years, representing more than 50% of its current reserve base.*

GREAT EXPLOITATIONS

XTO Energy was started from scratch. Unlike many of our peers, we had no asset base from which to grow and no cash flow for support. However, we did have solid experience and a strategic directive . . . acquire great properties and make great things happen.

Since inception, XTO Energy has consistently executed on this "directive." We target large positions in long-lived, operated properties. The reasons are evident: big positions offer more opportunities to employ good ideas, "long-lived" implies shallow production decline and healthy cash flow from which to grow and, finally, being the operator, we can control our destiny. These criteria have resulted in our "rifle shot" approach to acquisitions. We know what properties we want and we pursue those with gusto.

To date, results have been stellar. Our 2.68 Tcfe of proved reserves exceeds our total acquisition purchases of 2.33 Tcfe, *meaning we have "discovered"* all of our sold production volumes and more since the Company's inception.

Our acquisition game plan may not be appropriate for all companies or all investors. But for XTO Energy, the strategy has proven sound. We believe great acquisitions build great exploitations.


Qaanaaq
(Thule)
Inuvik
Dawson
Cambridge Bay
Victoria
Island
Baffin
Island
Iqaluit
(Frobisher Bay)
Repulse Bay
Echo Bay
Whitehorse
Kangiqcliniq
(Rankin Inlet)
Ivujivik
Yellowknife
Watson
Lake
Hay River
CAN
Churchill
Prince Rupert
Prince
George
Chisasibi
ROCKY
Edmonton
Calgary
Saskatoon
Moosonee
Vancouver
Regina
Seattle
Winnipeg
Thunder
Bay
Lake Superior
MOUN
Toronto
Hamilton
Minneapolis
Milwaukee
Detroit
Windsor
UNITED
Cleveland
Chicago
Pittsburgh
Columbus
Indianapolis
St. Louis
Denver
Kansas City
STATES
Memphis
Oklahoma City
Albuquerque
Phoenix
Jacksonv
Ciudad
Juárez
New Orleans
San
Antonio
Houston
Hermosillo
Chihuahua
Monterrey
Torreón
MEXICO
Cancún

2001 Development Events

With our most ambitious development and exploration program to date, we drilled 285 new wells and performed 425 workovers and recompletions on existing producing wells.

Of the new wells, 90% were concentrated in XTO's core gas-producing regions: East Texas Basin (104 wells), Arkoma Basin (70 wells), San Juan Basin (45 wells), northwest Oklahoma's Anadarko Basin (33 wells) and Wyoming's Green River Basin (6 wells).

Drilling efforts for oil reserves focused on our long-lived properties in West Texas and Alaska. Drilling in the Permian Basin included 18 vertical wells and 9 horizontal sidetracks: University Block 9 (3 vertical wells, 9 horizontal sidetracks), Prentice Northeast Unit (10 wells) and the Cornell Unit (5 wells). In the Middle Ground Shoal Field in Alaska's Cook Inlet, we drilled three high-angle sidetrack wells from our platform.

2002 Plans

This upcoming year offers tremendous opportunities to add reserves in our low-risk, highly successful development plays. We have allocated $400 million to deliver 17% to 20% gas production growth from 2001 levels, equating to overall growth of about 15% on an Mcfe basis. East Texas will utilize 65% of the funds in the Freestone Trend. The Arkoma and San Juan basins will share about 20% of the budget to continue their expansion. The exploration budget is pegged at $15 million. In total, our Company plans to drill 295 new wells and perform 515 workovers for the year.

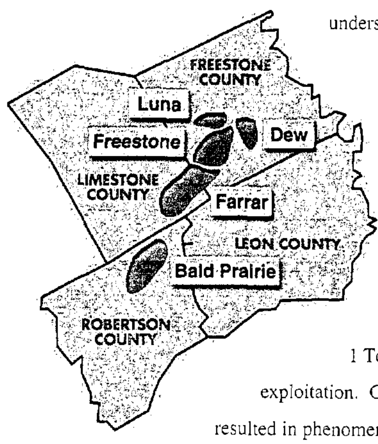
LEGACY ASSETS

EAST TEXAS

Impact: The use of high-rate water-fracturing techniques with minimum proppant has transformed tight rock formations into prolific pay zones at about one-third the cost of conventional "gelled fracs."

In spring of 1998, XTO Energy purchased properties in eight East Texas fields producing 80 MMcf per day on a shallow decline. Our experience and intuition led us to believe the 251 Bcfe of booked reserves was understated. We never planned on being so right.

East Texas

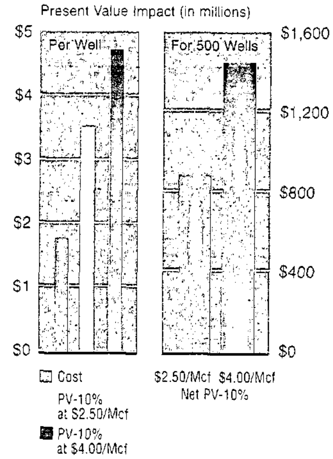


With follow-on acquisitions and exploitation, our East Texas assets have grown to 1.2 Tcfe of proved reserves with a current production rate topping 215 MMcf per day, up about 165%. Even more impressive, after drilling 180 wells, our engineers and geologists have identified more than 1 Tcfe of additional reserve potential for exploitation. Our hard work and good fortune have resulted in phenomenal "exploration-type" success delivered through a low-risk development program. For XTO Energy and its owners, the world has changed.

The Freestone Trend

In late 2000, after two years of fieldwork, XTO Energy announced a "discovery" in the heart of the basin. Unlike a single, high-risk exploration event, this "find" was generated through rigorous development activities and engineering innovation. Today, our Freestone Trend has become the centerpiece of XTO's development efforts.

East Texas Freestone Trend
Present Value Impact (in millions)



Clearly stated, the play is a massive, structurally defined trend with multiple pay zones. Seismic and wellbore data have allowed for a more precise geologic interpretation of the area. Forming the base is a productive feature, the Cotton Valley Lime, over which thick gas-bearing sandstones are draped. In essence, several thousand feet of sediments, the Bossier, Cotton Valley and Travis Peak sandstones, were deposited over these "structural highs," forming a stacked sequence of pay intervals. As depicted in the "Cross Section" visual below, the expansive productive intervals in each well offer tremendous reserve opportunities . . . 1 to 3 Bcf per formation.

At XTO, we have devised, tested and now implemented a plan to capture this embedded value. Our success is based on our innovative completion techniques. We fracture-stimulate each interval with a high-pressure, high-rate water solution to hydraulically crack the rock in a lateral plane. The water carries sand deep into the formation's dense matrix, creating a conduit through which gas can easily flow. This technique avoids damage while freeing up the tightly bound gas. Then, we commingle the zones and produce them simultaneously up the same wellbore. As a result, our wells achieve higher production rates, maximum reserves and richer present-value economics. On a portfolio of 500 wells, the economic impact to XTO should exceed a net PV-10% value of $1 billion. Put into perspective, this "discovery" should translate to about $8 per share for investors over time.

Over the course of 2001, XTO's position in the trend expanded from about 20,000 net acres to more than 65,000 acres today. In fact, we are still delineating the productive limits of the play. Our technical team expects the well location inventory to expand further as 2002 progresses.

Development Highlights

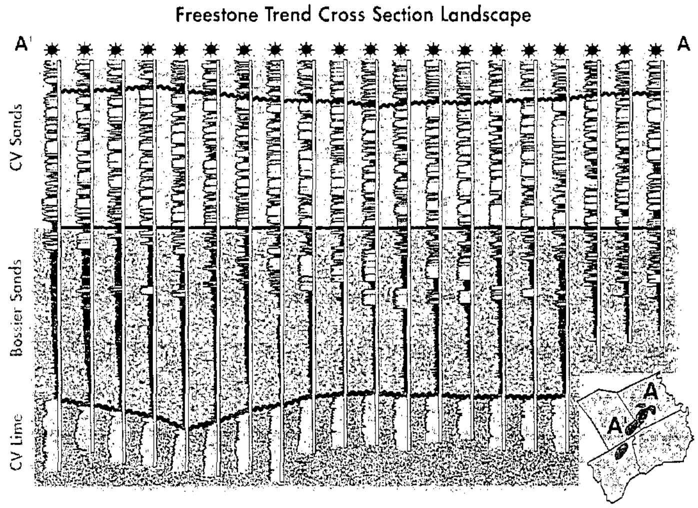
In 2001, gas production volumes in East Texas increased by 50%, driven primarily by Freestone Trend development. Our activities were concentrated in the trend's five fields: Freestone, Farrar, Bald Prairie, Dew and Luna. In this area, we drilled 84 wells during the year, bringing the total to 103 since acquisition. Superior results have seen the average well add 2.4 Bcfe of gas reserves.

Also, our operational team completed the construction of a 27-mile pipeline and associated gas plant. This network effectively connects our major fields and allows for the most economic and efficient transportation of our gas. As a result, the infrastructure to handle our future production growth is now in place.

For 2002, XTO plans to drill 144 new wells with 134 targeting the high-impact Freestone Trend. A total of 60 workovers and recompletions will be implemented through the course of the year.

Total XTO Production in 2001: 69 Bcfe

Freestone Trend Cross Section Landscape

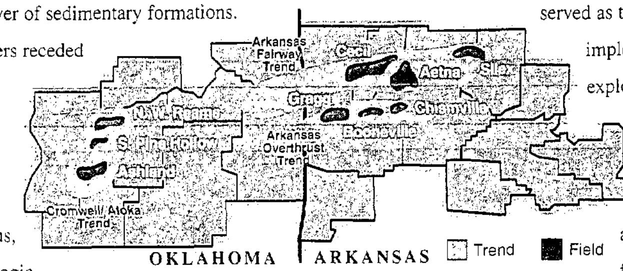


ARKOMA BASIN

Impact: *The use of formation-imaging well logs has led to more precise interpretation of geology and, ultimately, finding new gas reservoirs.*

Eons ago, a series of river systems dumped a constant wash of sediments into expansive shallow waters. Over the millennia, these giant coastal plain deposits accumulated, creating layer upon layer of sedimentary formations. Eventually, as the waters receded and mountain chains moved, thousands of feet of buried intervals became fractured, faulted and tilted. Thus, a highly complex geologic region was formed — in this instance, the Arkoma Basin.

Arkoma Basin



The characteristics of this long-lived gas basin perfectly suit our exploitation machine: stacked reservoirs ranging from 1,500 feet to 9,000 feet down, a geology that is difficult to interpret and a lag in technology implementation. All criteria point to immense opportunity for an innovative and opportunistic XTO Energy.

With our core acquisitions of about 430 Bcfe, XTO entered the Arkoma in grand fashion, immediately becoming the top gas producer in Arkansas with more than 40% of the state's gas production. Our 500,000 acres of exposure will enable XTO to leverage development ideas on a large scale. After two full years, our ambitious exploitation plan has taken hold with both production and reserves having increased by about 20%. Importantly, we recognize more than 200 drilling locations to extend development over the next several years.

"Our management philosophy guides the Company as an entrepreneurial venture."

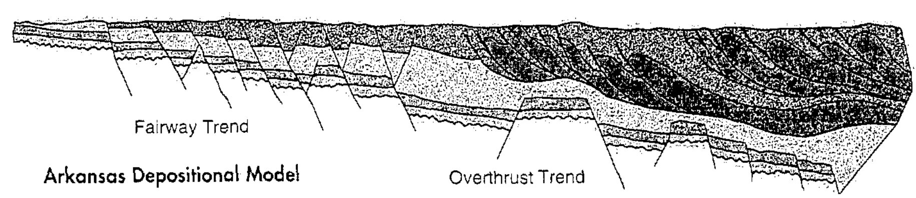
– Keith A. Hutton
Executive VP, Operations

Development Highlights

XTO's Arkoma operations are separated into three areas with distinct regional attributes: the Arkansas Fairway Trend, the Arkansas Overthrust Trend and the Oklahoma Cromwell/Atoka Trend.

In 2001, our activities focused on the Fairway Trend properties, which deliver 80% of our total daily gas production in Arkoma. Within the Fairway, the Aetna Field has served as the "case study" for initial implementation of our three-stage exploitation model. First, operation efforts in the field improved well performance with artificial lift and compression facility upgrades. Then, fracture stimulations were used to invigorate production on eight wells. Daily rates increased an average of 500 Mcf per well. Finally, our comprehensive study of the field's geology identified locations for new drilling to capture untapped reservoirs. These new wells are prolific producers and a deeper test has proved-up a discovery in the Viola/Hunton intervals.

Most importantly, our systematic process in Aetna led the XTO team to develop our "fault block analysis" technique. This methodology matches geologic interpretation of wellbore data with completion/production performance within the boundaries of an isolated fault block. The analysis generates additional recompletion activities and well locations within this controlled block. We are now using this analytical technique to identify drilling locations across the entire Arkoma Basin.



Arkansas Depositional Model

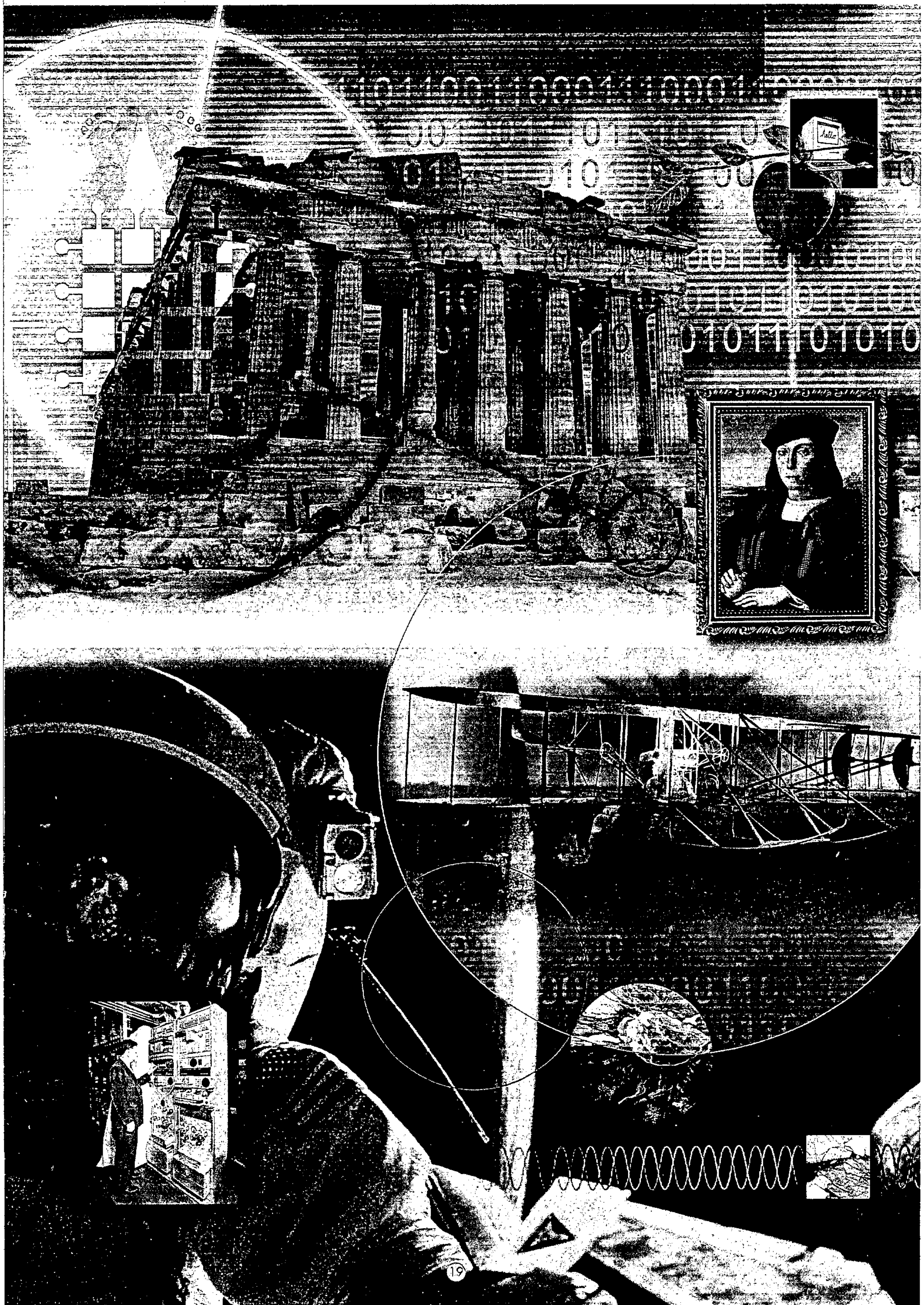
XTO Energy began as an entrepreneurial venture. Our management team has built this Company and imbued the culture with entrepreneurial spirit: commit to the venture, embrace the challenge and share in the rewards.

Today, with 750 employees and a market capitalization of about $2.4 billion, that same quest for entrepreneurial excellence invigorates the XTO work environment. Relationships, respect and dedication drive the entrepreneur — qualities that are prevalent throughout our organization. Each employee shares in

E N T R E P R E N E U R I A L   E X C E L L E N C E

the Company's mission to "create and realize value." Each department is called upon to contribute. We brainstorm, we huddle in adversity, we work late hours and we pay acute attention to the details. Like any good proprietor, we know the defining scorecard for a successful business relies on consistent economic returns.

Whether geophysicist or accountant or lease operator, we all work hard to make a positive impact. Our collective entrepreneurial spirit pushes us to be judged as a great business. At XTO, we just happen to also be a great energy company.



In 2002, XTO plans to drill 55 wells, with about half directed to continue development of the Oklahoma Cromwell/Atoka Trend and extension of the Arkansas Overthrust Trend. More than 150 workovers are planned for the year, including recompletions, stimulations and compressor installations. Furthermore, late in 2002, an exploration prospect should be drilled in the South Pine Hollow Field in Oklahoma.

Total XTO Production in 2001: 42 Bcfe

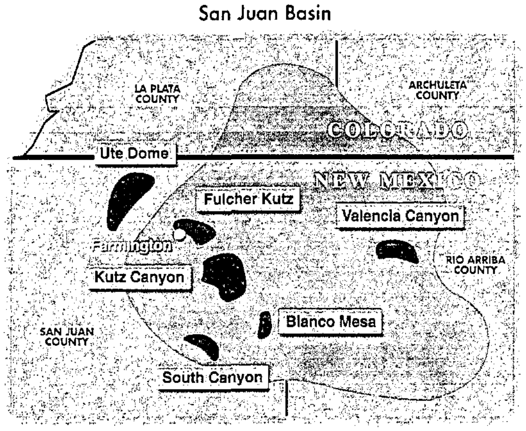
SAN JUAN BASIN

Impact: *Effective design and installation of wellhead compressors have increased reserves by 200 MMcf per well.*

Simply put, this gas basin is overwhelmed with hydrocarbons. Productive horizons stack up in wellbores, beginning with coal seam gas at 1,500 feet down to the Paradox Formation at 9,000 feet. Over the years, these stratigraphic riches have provided cycles of development and fueled the growth of many energy companies. At XTO, we have enjoyed the same fortune with our properties.

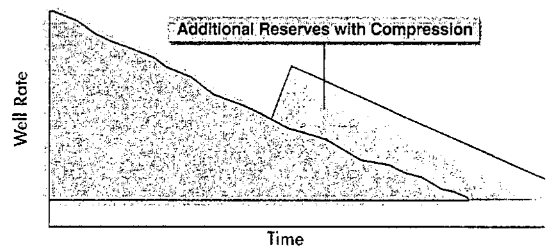
In 1997, we acquired a modest foothold in northwest New Mexico with an acquisition of 290 Bcfe producing at 48 MMcf per day. To date, our realized reserves have grown to more than 500 Bcfe, while the daily production rate has rocketed by 76% to 79 MMcf. Importantly, the majority of this growth has resulted from the "first stage" of our exploitation model — 100% ROR operational events.

San Juan Basin



In the basin's history, overall gas production has often been hindered by infrastructure issues. These include pipeline capacity constraints coupled with high operating pressures. Our technical team has designed wellhead compression units that overcome these limitations. Wells have responded by yielding higher production rates. Over four years, we have installed 350 compressors. Based on their performance, this program has added gross reserves of 70 Bcf and enhanced the average PV-10% economics of each well by $140,000. More than 100 additional wells are targeted for compression facilities during 2002.

Wellhead Compression
Generating Reserves and Production



Development Highlights

XTO Energy's 2001 San Juan Basin development program included 45 new wells and 190 workovers and recompletions. The exploitation inventory continues to grow across our San Juan properties. Currently, we have identified more than 300 well locations, a five-year inventory of low-risk drilling prospects.

Over the past three years, Fruitland Coal development has exceeded all expectations. Daily production from the coal seam has grown to about 16 MMcf, up from 2 MMcf. Drilled to 2,000 feet, these low-cost prolific wells yield some of the strongest drilling economics in the Company. In 2001, several extension wells confirmed new productive areas of coalbed methane gas for development. Currently, we see 30 new drilling locations which should deliver 1 to 3 Bcf per well at about $.20 per Mcfe, yielding 80% ROR economics.

For a petroleum engineer, the conventions of completing a new well dictate that each "pay zone" in the wellbore should be produced and depleted separately, starting from the deepest interval and recompleting uphole to each successive shallower section. As a result, reserves will be maximized and the risk of failure minimized.

At XTO Energy, we prefer to question convention.

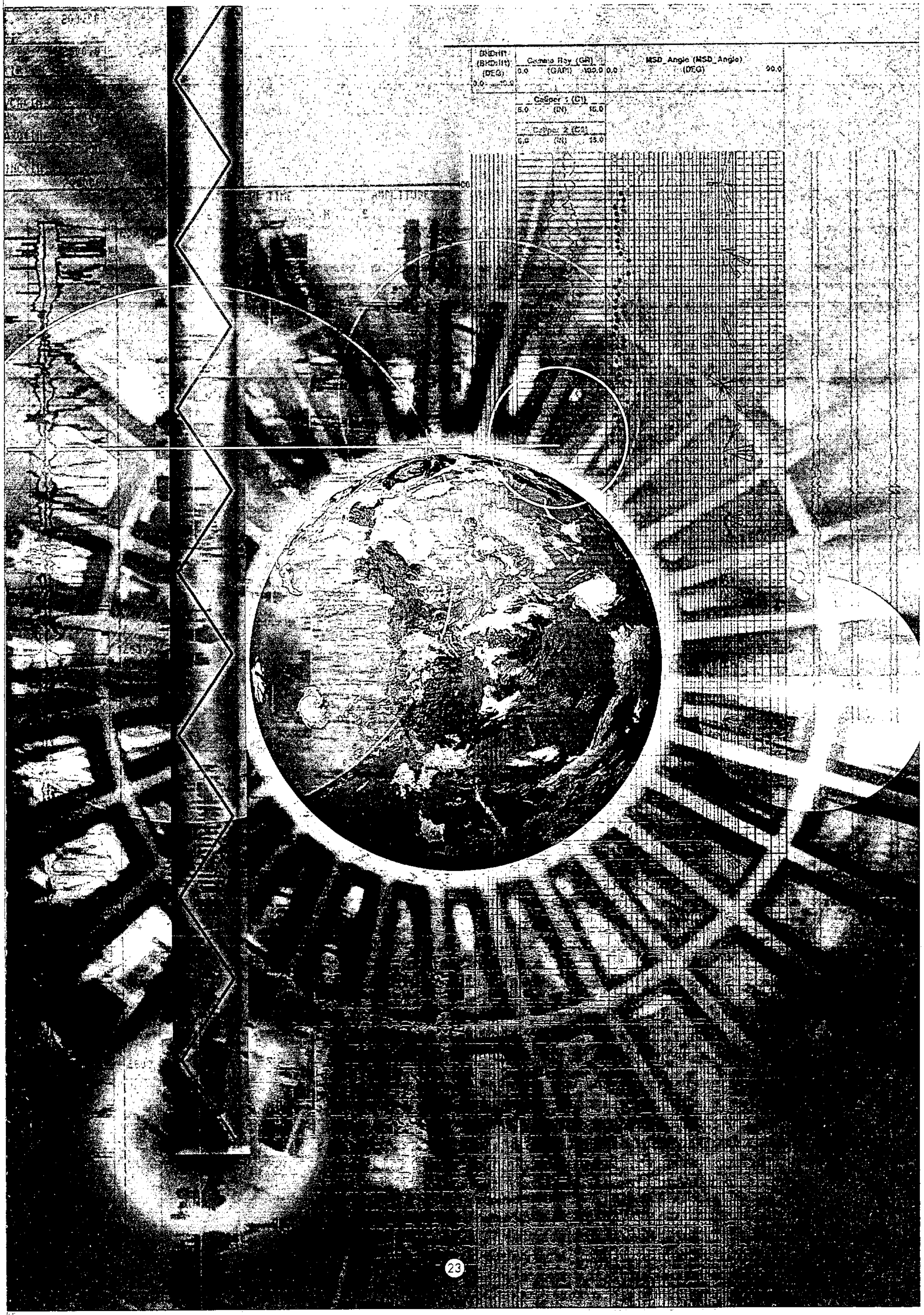
Although technically sound, this engineering approach compromises financial returns. To maximize the present value of this investment, we propose that the new well should produce

INNOVATING EXCEPTIONAL TECHNOLOGY

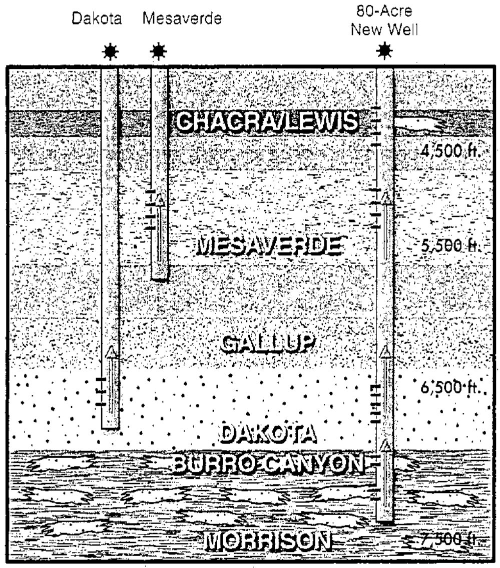
from all pay zones simultaneously. So our engineers assess plausibility, weigh risks and design a solution. We call it "commingling" . . . *realizing cumulative* rate with higher cash flow while delivering maximum reserves. It seems a small innovation, but when applied company-wide, the technique yields a phenomenal impact.

At XTO Energy, we believe that new ideas are the "building blocks" to great fortune. Many times over, creative thinking in our technically complex arena has generated clever ways to recover more oil and gas in the field.

This is our expertise — turning new ideas into cash.


(DEG)
(GAPI)
MSD_Angle (MSD_Angle)
(DEG)
90.0
(IN)
16.0

Mesaverde/Dakota Formation
Dual Completion Development



Single Zone Completions (2 Wells) Multiple Zones Commingled (1 Well)

Our development plans for the deeper Mesaverde and Dakota sandstones have gained momentum as both formations are now approved for 80-acre spacing. This event opens the door to more than 200 new well locations. We will employ the same commingling completion techniques used elsewhere in the Company to produce multiple formations simultaneously in a single wellbore. As a result, attractive economics can be expected at a lower overall cost and with reduced risk. We expect a typical well will deliver 1.5 Bcf of reserves at a cost of only $.50 per Mcf. Average initial rates for these wells should approach 1 to 2 MMcf per day.

As further upside for our Mesaverde/Dakota wells, we plan to drill "exploration tails" in each well to penetrate the deeper Burro Canyon and Morrison sands. The Company has completed several wells in these new productive horizons. Our wells have flowed at initial daily rates of 1 to 4 MMcf, with no stimulation treatments. These flush stratigraphic traps deliver an additional 2 to 4 Bcf per well. These new intervals offer an exciting promise of yet another wave of development upsides in the basin.

Our plans for 2002 include drilling 48 new wells and performing 190 workovers and recompletions.

Total XTO Production in 2001: 30 Bcfe

HUGOTON ROYALTY TRUST AREA

Impact: "Energized" fracture stimulations are doubling gas production rates in Chase Formation wells.

The gas-saturated sediments of the Mid-Continent, from the Anadarko Basin to the Hugoton Field and up into Wyoming, have provided the nation a premium source of natural gas since the 1920s. In almost every case, the properties in this territory have out-produced and out-lived expectations, making this a definitive example of a "legacy asset."

Over the past 15 years, XTO has amassed substantial holdings in the Mid-Continent. Currently, we produce a gross volume of more than 100 MMcf per day of natural gas from the region. Our technical ingenuity has consistently enhanced well performance and our delineation drilling has repeatedly extended the limits of the numerous pay zones.

In 1998, the Company carved the Hugoton Royalty Trust (HGT) out of our Mid-Continent property base and subsequently sold units to the public. Overall, we have maintained a 63% ownership interest in these assets and our XTO team continues to operate and effectively develop these properties.

Development Highlights

The numerous and diverse reservoirs in western Oklahoma, ranging from 6,500 feet to 9,400 feet, provide ongoing opportunities for exploitation. Our efforts in designing new stimulation and recompletion techniques have continued to increase gas production.

In 2001, the Company drilled 33 wells targeting both the Mississippi (Osage) Trend in Major County and the Chester Formation in Woodward County. Our steady development program calls for drilling 12 wells during 2002.

In the Hugoton Field, North America's largest gas field, XTO's operational team is utilizing "foam-fracs" to restimulate older Chase Group intervals and increase production. In 2001, we performed successful stimulations on 27 wells. Another 150 candidates for stimulation have been identified.

The deep sandstones of the Green River Basin in Wyoming have provided the Company upside opportunities through a steady infill drilling program. Production from our Fontenelle Field continues to hold above 27 MMcf per day. In 2001, six new wells were drilled to the Frontier sandstone intervals with an average daily rate of 800 Mcf and reserves of 1.5 Bcf per well.

Total XTO Production in 2001: 26 Bcfe

PERMIAN BASIN

Impact: *Our multi-lateral, horizontal sidetracks from existing wellbores are accessing reserves equivalent to those of a vertical well at half the cost.*

Long-lived oil and gas production from a property translates into predictable and sustained cash flow. In West Texas, XTO Energy owns and operates several of these premium assets: University Block 9, the Prentice Northeast Unit and the Cornell Unit. Year after year, these quality properties continue to provide development upsides as a result of the complex multi-pay nature of the basin. Together, our properties produce about 7,300 BOPD for the Company.

Development Highlights

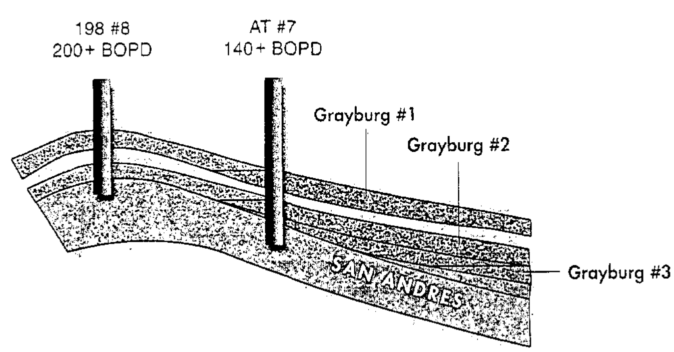
In University Block 9, we focused on our continuing development of the Devonian Formation with three new vertical wells and nine sidetracks. Our efforts led to discovery of a new Grayburg interval on the west flank of our properties. Initial Grayburg wells have produced from 140 to 200 BOPD and reflect reserves of 100 to 150 MBO. With its low costs, this discovery will add a new round of exploitation for a field that has been producing since 1953.

In the Prentice Northeast Unit, we continued to infill drill this expansive waterflood property on 10-acre spacing. Since 1995, the Company has maintained a relatively flat oil production profile with our ongoing development program. New wells add about 80 BOPD in rate and 70 MBO in reserves. We have identified another 40 locations to drill at our current pace of 10 wells per year.

In our Cornell Unit of the Wasson Field, the development program concentrated on drilling wells into the San Andres Formation. The five new 10-acre wells in 2001 realized reserves of about 90 MBOE at a $3 per Bbl finding cost. The Company plans to drill another 30 to 50 wells in the field in an ongoing plan to maintain production volumes. Importantly, we are now testing the viability of expanded gas production with a three well pilot program into the "gas-cap."

Total XTO Production in 2001: 18 Bcfe

University Block 9
New Grayburg Discovery



Impact: *Applying 3-D visualization to reservoir analysis has allowed XTO to identify trapped oil reserves and improve waterflood design.*

Our geoscience team has tackled a unique challenge in the Cook Inlet: modeling an extremely complex reservoir to potentially recover 30 million barrels of oil.

In 1998, XTO Energy found an opportunity to create tremendous value in Alaska by applying our extensive waterflooding experience garnered from our efforts in West Texas. We purchased the Middle Ground Shoal Field, which has recovered over 120 million barrels of oil since discovery in the 1960s. With new seismic processing and reservoir simulation techniques, our team believes we can identify isolated oil pockets and improve total recoveries in the field. We embarked on a development program to increase production volumes and have been successful. Today, daily oil production is 4,350 Bbls, up from 3,600 Bbls only two years ago.

"Decisions – strategic, financial, operational – are based on the integrity of the investment process."
– Louis G. Baldwin
Executive VP and CFO

Development Highlights

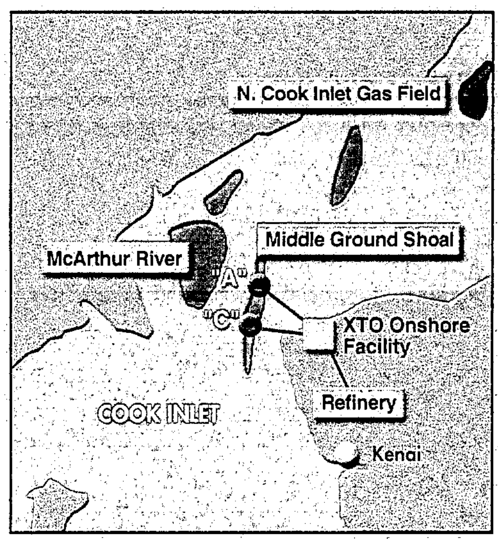
Current efforts are concentrated on the vertically oriented West Flank of the multi-zone reservoir. In 2001, we drilled three horizontal sidetrack wells from our "A" Platform, realizing average initial rates of about 500 BOPD and 750 MBO of reserves. Our operations have also converted three producing wells to injectors in order to improve sweep efficiency in the flood pattern. Eventually, we expect the total production rate to approach 5,000 BOPD.

In 2002, three new wells are scheduled for the West Flank, with costs projected at $3.5 million per well and reserves targeted at 750 MBO. A waterflood simulation model of the East Flank is also underway to assess options to maximize its ultimate oil recovery.

Meanwhile, the Company looks to the deeper Jurassic sediments, 1,500 feet beneath our producing Tyonek Formation, as a possible exploration zone. In 1990, a test well in the McArthur River Field produced oil at a substantial rate before being damaged. This year an additional test well is planned by another operator in the vicinity.

Total XTO Production in 2001: 8 Bcfe

Alaska's Cook Inlet



The goal is simple — be an enduring investment.

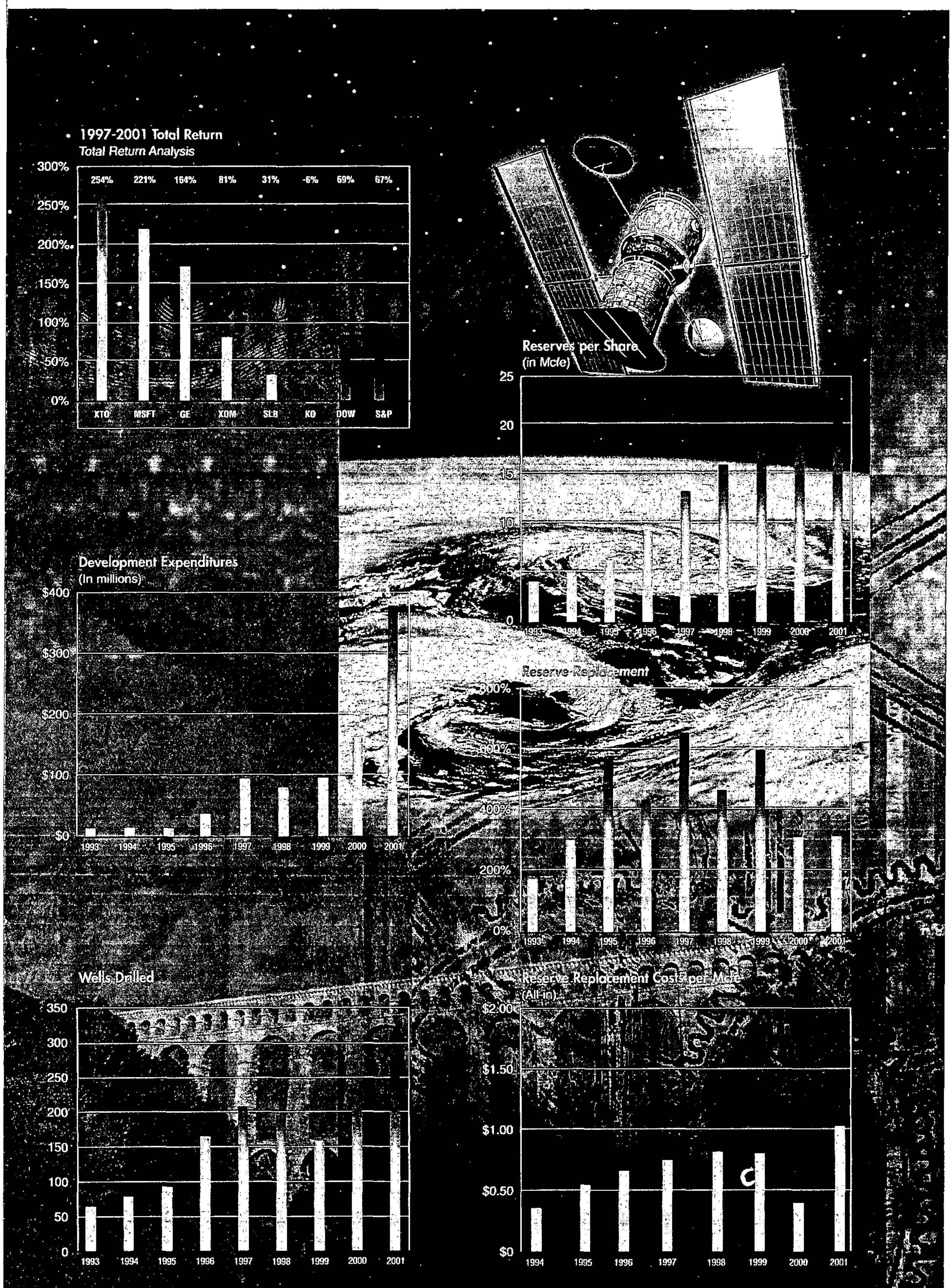
In a commodity business, the concept is definitely easier said than done. Erratic cycles drive erratic performance. A glimpse of "total returns" for an average E&P stock over the past five years exposes reality: expect marginal performance at best. But all companies are not created equal. A look at XTO Energy's total return tells a different tale. The Company's stock is up 254% over the same period. So what's the distinction?

Back to the original point — be an enduring investment.

AN EXEMPLARY INVESTMENT

Across industries, the traits of an investment vehicle are essentially the same: a franchise with a proven track record, quality assets, strong margins and innovative operations; a solid strategy with visible growth; a commitment to value creation per share; and most importantly, visionary management. These criteria define XTO Energy. From our stock price history, the market has ultimately believed the same.

As investors, you place confidence in us. As management, we have profound confidence that our organization will deliver. Together, we are continuing to build an exemplary investment.



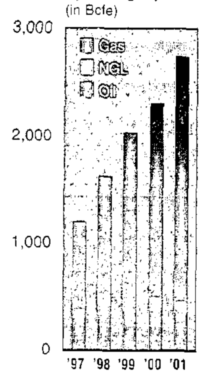
1997-2001 Total Return
Total Return Analysis
300%
250%
200%
150%
100%
50%
0%
254%
221%
164%
81%
31%
-6%
69%
67%
XTO
MSFT
GE
XOM
SLB
KO
DOW
S&P
Reserves per Share
(in Mcfe)
25
20
15
10
5
0
1993
1994
1995
1996
1997
1998
1999
2000
2001
Development Expenditures
(In millions)
$400
$300
$200
$100
$0
1993
1994
1995
1996
1997
1998
1999
2000
2001
Reserve Replacement
800%
600%
400%
200%
0%
1993
1994
1995
1996
1997
1998
1999
2000
2001
Wells Drilled
350
300
250
200
150
100
50
0
1993
1994
1995
1996
1997
1998
1999
2000
2001
Reserve Replacement Costs per Mcfe
(All-in)
$2.00
$1.50
$1.00
$0.50
$0
1994
1995
1996
1997
1998
1999
2000
2001

Reserves and Production

Estimated proved oil and gas reserves at year-end 2001 totaled 2.68 Tcfe, up 19% from 2.25 Tcfe at year-end 2000. This translates to 22 Mcfe for each share of the Company's common stock. Without downward revisions due to lower commodity prices, proved reserves would have been 2.86 Tcfe, up 27%.

Natural gas reserves increased 26% to 2.24 Tcf, and natural gas combined with NGLs of 20.3 million Bbls equaled 88% of total reserves. Oil reserves decreased 8% to 54.0 million Bbls due to lower oil price assumptions. Proved developed reserves accounted for 67% of total proved reserves on an Mcfe basis. At year-end 2001, the Company's reserve-to-production index was 14.8 years.

Proved Reserves by Category
(in Bcfe)



Despite a 181 Bcfe reduction caused by lower commodity prices, the Company replaced 624 Bcfe through acquisitions and development, or 326% of 2001 production at a cost of $1.01 per Mcfe. Through development efforts only, we replaced 191% of production at a cost of $1.08 per Mcfe. Excluding the effects of downward revisions due to pricing, the Company would have added a total of 805 Bcfe, or 420% of production, at $.79 per Mcfe, with 541 Bcfe, or 282% of production, coming from development at $.73 per Mcfe.

During 2001, the Company produced 5.0 million Bbls of oil, 1.6 million Bbls of NGLs and 152.2 Bcf of natural gas. Daily oil and NGLs production averaged 18,022 Bbls, up 4% from 2000 levels. Daily gas production averaged 416.9 MMcf, up 21% from 343.9 MMcf in 2000.

As of December 31, 2001, estimated future net cash flows before income tax totaled $3.8 billion based on realized prices of $17.39 per Bbl of oil, $2.36 per Mcf of gas and $8.70 per Bbl of NGLs. The present value before income tax, discounted at 10%, was $1.9 billion, compared to the year-end 2000 level of $7.7 billion. Realized prices at year-end 2000 were $25.49 per Bbl of oil, $9.55 per Mcf of gas and $26.33 per Bbl of NGLs.

As a price sensitivity case for 2001, assuming $25.00 per Bbl of oil, $3.50 per Mcf of gas (NYMEX) and $16.00 per Bbl of NGLs, estimated future net cash flows, before income taxes, would have totaled $6.7 billion while the present value before income taxes, discounted at 10%, would have equaled $3.5 billion. Importantly, total proved reserves would have increased to 2.79 Tcfe, reclaiming more than 60% of the reserves lost to pricing revisions.

Our average gas price for 2001 rose 33% to $4.51 per Mcf from $3.38 in 2000. Oil prices in 2001 averaged $23.49 per Bbl, down from $27.07 per Bbl in 2000. The NGL price per Bbl averaged $15.41, down 21% from the 2000 price of $19.61.

Proved Oil & Gas Reserves

December 31, 2001
(in thousands)

	Oil (Bbls)	Gas (Mcf)	NGLs (Bbls)	Mcfe
Proved developed	41,231	1,452,222	14,774	1,788,252
Proved undeveloped	12,818	783,256	5,525	893,314
Total proved	54,049	2,235,478	20,299	2,681,566
Estimated future net cash flows, before income tax				$ 3,756,602
Present value before income tax				$ 1,947,441

Changes in Proved Reserves

(in thousands)

	Oil (Bbls)	Gas (Mcf)	NGLs (Bbls)	Mcfe
December 31, 2000	58,445	1,769,683	22,012	2,252,425
Revisions	(4,201)	(96,990)	(2,193)	(135,354)
Extensions and discoveries	3,317	469,602	2,081	501,990
Production	(4,978)	(152,178)	(1,601)	(191,652)
Purchases in place	1,484	248,339	–	257,243
Sales in place	(18)	(2,978)	–	(3,086)
December 31, 2001	54,049	2,235,478	20,299	2,681,566

Based on SEC assumptions

E X C E P T I O N A L   L E A D E R S H I P

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Standing (left to right): Louis G. Baldwin, Dr. Lane G. Collins, Steffen E. Palko, Keith A. Hutton, Bob R. Simpson, Vaughn O. Vennerberg II, William H. Adams III, Jack P. Randall, J. Luther King, Jr.
Seated (left to right): Scott G. Sherman, Herbert D. Simons

Selected Financial Data

In thousands except production, per share and per unit data	2001	2000	1999	1998	1997
CONSOLIDATED INCOME STATEMENT AND CASH FLOWS DATA (a)					
Revenues:					
Oil and condensate	$ 116,939	$ 128,194	$ 86,604	$ 56,164	$ 75,223
Gas and natural gas liquids	710,348	456,814	239,056	182,587	110,104
Gas gathering, processing and marketing	12,832	16,123	10,644	9,438	9,851
Other	(1,371)	(280)	4,991	1,297	3,094
Total revenues	$ 838,748	$ 600,851	$ 341,295	$ 249,486	$ 198,272
Earnings (loss) available to common stock	248,816 (b)	$ 115,235 (c)	$ 44,964 (d)	$ (71,498) (e)	$ 23,905
Per common share (f)					
Basic	$ 2.03 (g)	$ 1.08	$ 0.43	$ (0.73)	$ 0.27
Diluted	$ 2.00 (g)	$ 1.03	$ 0.42	$ (0.73)	$ 0.26
Weighted average common shares outstanding (f)	122,505	106,730	105,341	97,640	89,490
Dividends declared per common share (f)	$ 0.0367	$ 0.0222	$ 0.0178	$ 0.0711	$ 0.0667
Operating cash flow (h)	$ 549,567	$ 344,638	$ 132,683	$ 78,480	$ 89,979
CONSOLIDATED BALANCE SHEET DATA (a)					
Property and equipment, net	$ 1,841,387	$ 1,357,374	$ 1,339,080	$ 1,050,422	$ 723,836
Total assets	$ 2,132,327	$ 1,591,904	$ 1,477,081	$ 1,207,005	$ 788,455
Long-term debt	$ 856,000	$ 769,000	$ 991,100	$ 920,411	$ 539,000
Stockholders' equity	$ 821,050	$ 497,367	$ 277,817	$ 201,474	$ 170,243
OPERATING DATA (a)					
Average daily production:					
Oil (Bbls)	13,637	12,941	14,006	12,598	10,905
Gas (Mcf)	416,927	343,871	288,000	229,717	135,855
Natural gas liquids (Bbls)	4,385	4,430	3,631	3,347	220
Mcfe	525,062	448,098	393,826	325,390	202,609
Average sales price:					
Oil (per Bbl)	$23.49	$27.07	$16.94	$12.21	$18.90
Gas (per Mcf)	$ 4.51	$ 3.38	$ 2.13	$ 2.07	$ 2.20
Natural gas liquids (per Bbl)	$15.41	$19.61	$11.80	$ 7.62	$ 9.66
Production expense (per Mcfe)	$ 0.57	$ 0.53	$ 0.53	$ 0.53	$ 0.59
Taxes, transportation and other (per Mcfe)	$ 0.33	$ 0.35	$ 0.23	$ 0.25	$ 0.22
Proved reserves:					
Oil (Bbls)	54,049	58,445	61,603	54,510	47,854
Gas (Mcf)	2,235,478	1,769,683	1,545,623	1,209,224	815,775
Natural gas liquids (Bbls)	20,299	22,012	17,902	17,174	13,810
Mcfe	2,681,566	2,252,425	2,022,653	1,639,328	1,185,759

(a) Significant producing property acquisitions in each of the years presented affect the comparability of year-to-year financial and operating data.

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

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

(d) Includes effect of a $40.6 million pre-tax gain on sale of Hugoton Royalty Trust units.

(e) Includes effect of a $93.7 million pre-tax net loss on investment in equity securities and a $2 million pre-tax, non-cash impairment charge.

(f) Adjusted for the three-for-two stock splits effected on March 19, 1997, February 25, 1998, September 18, 2000 and June 5, 2001.

(g) Before cumulative effect of accounting change, earnings per share were $2.39 basic and $2.35 diluted.

(h) Defined as cash provided by operating activities before changes in operating assets and liabilities and exploration expense.

Management's Discussion and Analysis

General

The following events affect the comparability of results of operations and financial condition for the years ended December 31, 2001, 2000 and 1999, and may impact future operations and financial condition. 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.

Three-for-Two Stock Splits. The Company effected three-for-two stock splits on September 18, 2000 and June 5, 2001. All common stock shares, treasury stock shares and per share amounts have been retroactively restated to reflect all stock splits.

2001 Acquisitions. During 2001, the Company acquired predominantly gas-producing properties at a total cost of $242 million primarily funded by bank borrowings and operating cash flow. The acquisitions include:

- *Herd Acquisition.* In January 2001, the Company acquired gas properties in East Texas and Louisiana for $115 million from Herd Producing Company, Inc.
- *Miller Acquisition.* In February 2001, the Company acquired gas properties in East Texas for $45 million from Miller Energy, Inc. and other owners.

1999 Acquisitions. During 1999, the Company acquired predominantly gas-producing properties at a total cost of $510 million primarily funded by a combination of bank borrowings, proceeds from a public offering of common stock and the issuance of common stock. The acquisitions include:

- *Spring Holding Company Acquisition.* In July 1999, the Company and Lehman Brothers Holdings, Inc. each acquired 50% of the common stock of Spring Holding Company for a combination of cash and the Company's common stock totaling $85 million. In September 1999, the Company acquired Lehman's 50% interest in Spring for $44.3 million. The acquisition included gas properties located in the Arkoma Basin of Arkansas and Oklahoma with a purchase price of $235 million. After purchase accounting adjustments and other costs, the cost of the properties was $257 million.
- *Ocean Energy Acquisition.* In September 1999, the Company and Lehman acquired Arkoma Basin gas properties for $231 million. Lehman contributed $100 million in cash and the Company contributed $100 million in securities, including its common stock, to a jointly owned company. The acquisition was funded with cash of $100 million and bank borrowings of $131 million. The Company acquired Lehman's interest in this acquisition in March 2000 for $111 million, which was funded by proceeds from the sales of producing properties and equity securities, as well as bank debt. The $11 million in excess of Lehman's investment was recorded as additional property cost in 2000.

Hugoton Royalty Trust Sales. The Company created Hugoton Royalty Trust in December 1998 by conveying 80% net profits interests in producing properties in Kansas, Oklahoma and Wyoming. In April and May 1999, the Company sold 17 million units, or 42.5%, of Hugoton Royalty Trust in its initial public offering. Total proceeds from this sale were $148.6 million, which were used to reduce bank debt. Total gain on sale, including the sale of units pursuant to an employee incentive plan, was $40.6 million before income tax. In October and November 2000, the Company sold 1.2 million units, or approximately 3%, of Hugoton Royalty Trust pursuant to the employee incentive plan at a total gain of $11 million before income tax.

2000 Property Sales. In March 2000, the Company sold oil- and gas-producing properties in Crockett County, Texas and Lea County, New Mexico for total gross proceeds of $68.3 million.

1999 Property Sales. In May and June 1999, the Company sold primarily nonoperated gas-producing properties in New Mexico for $44.9 million. In September 1999, the Company sold primarily nonoperated oil- and gas-producing properties in Oklahoma, Texas, New Mexico and Wyoming for $63.5 million, including sales of $22.5 million of properties acquired in the Spring Holding Company Acquisition.

2001, 2000 and 1999 Development and Exploration Programs. Gas development focused on the East Texas area and the Arkoma and San Juan basins during 2001, and on the East Texas area and Fontenelle Unit during 2000 and 1999. Oil development was concentrated in Alaska during 2001 and in the University Block 9 Field during all three years. Exploration activity has been primarily geological and geophysical analysis, including seismic studies, of undeveloped properties. Exploratory expenditures were $5.4 million in 2001, $1 million in 2000 and $900,000 in 1999. Exploration expense for 2001 includes dry hole expense of $2.2 million.

2002 Development and Exploration Program. The Company has budgeted $400 million for its 2002 development and exploration program, which is expected to be funded primarily by cash flow from operations. The Company anticipates exploration expenditures will be approximately 4% of the 2002 budget. The cost of any property acquisitions during 2002 may reduce the amount currently budgeted for development and exploration. The total capital budget, including acquisitions, will be adjusted throughout 2002 to focus on opportunities offering the highest rates of return.

Common Stock Transactions. The following significant sales and issuances of common stock occurred during the three-year period ended December 31, 2001:

- In November 2000, the Company sold 9.9 million shares of common stock from treasury with net proceeds of approximately $126.1 million. The proceeds were used to reduce bank debt.
- In July 1999, the Company sold 4.5 million shares of common stock from treasury with net proceeds of approximately $26.5 million. The proceeds were used to repurchase 4.3 million shares of common stock issued for a 1998 acquisition.
- In July 1999, the Company issued 9 million shares of common stock for its 50% interest in Spring Holding Company and for cash proceeds of $3.2 million which was used to reduce bank debt.

Treasury Stock Purchases. The Company often repurchases shares of its common stock as part of its strategic acquisition plans. The Company purchased on the open market 7.9 million shares at a cost of $41.4 million in 2000 and 11,000 shares at a cost of $53,000 in 1999. As of March 27, 2002, 6.5 million shares remain under the May 2000 Board of Directors' authorization to purchase an additional 6.8 million shares.

Management's Discussion and Analysis

(continued)

Conversion of Preferred Stock. In 2000 and 2001, all outstanding preferred stock was converted into 5.5 million shares of common stock.

Investment in Equity Securities. In 1998, the Company purchased what it believed to be undervalued oil and gas reserves by acquiring common stock of publicly traded independent oil and gas producers at a total cost of $167.7 million. For accounting purposes, the Company considered equity securities purchased in 1998 to be trading securities since they were purchased with the intent to resell in the near future, and therefore recognized unrealized investment gains and losses in the income statements. After selling a portion of these securities in 1998 and 1999, the Company sold its remaining investment in equity securities in 2000 for $43.7 million. The Company recognized a gain of $13.3 million in 2000 and a loss of $1.1 million in 1999 related to this investment.

Hedging Activities. The Company enters futures contracts, collars and swap agreements, as well as fixed price physical delivery contracts, to hedge against unfavorable changes in product prices. During 2001, all hedging activities increased gas revenue by $97 million. Hedging activities reduced gas revenue by $40.5 million in 2000 and by $5.7 million in 1999, and reduced oil revenue by $7.8 million in 2000 and by $2.2 million in 1999. See "Product Prices – Gas" and table on page 37 for a summary of the Company's hedging positions at March 27, 2002.

Cumulative Effect of Accounting Change for Derivatives. On January 1, 2001, the Company adopted Statement of Financial Accounting Standards ("SFAS") No. 133 by recording a one-time after-tax charge of $44.6 million in the income statement for the cumulative effect of a change in accounting principle and an unrealized loss of $67.3 million in accumulated other comprehensive income, which is an element of stockholders' equity. The unrealized loss was related to the derivative fair value of cash flow hedges. The charge to the income statement was primarily related to the Company's gas physical delivery contract at crude oil-based prices.

Derivative Fair Value Gain/Loss. The Company has recorded realized derivative gains and losses in its income statements and unrealized derivative gains and losses associated with cash flow hedges in accumulated other comprehensive income. The Company recorded a $54.4 million gain in 2001 and a $55.8 million loss in 2000 related to changes in fair value of non-hedge derivatives. The 2000 loss and $29.5 million of the 2001 gain are related to the change in fair value of call options that the Company sold in 1999 as part of its hedging activities. Because written call options do not provide protection against declining prices, they do not qualify for hedge or loss deferral accounting. Most of the remaining gain in 2001 is related to the change in fair value of a gas physical delivery contract with crude oil-based pricing, the loss on which was initially recorded in the cumulative effect of accounting change for derivatives.

At December 31, 2001, the Company has recorded a net unrealized gain of $70.6 million (net of $38.1 million tax) in accumulated other comprehensive income related to the fair value of derivatives designated as cash flow hedges. The ultimate settlement value of these hedges will be recognized in the income statement as gas revenue when the related production occurs through 2002. The Company also has fixed price gas physical delivery contracts that are not expected to be net cash settled, and therefore, their fair value of $36.4 million is not recorded in the financial statements. Revenues from these contracts will be recognized as the commodity is delivered.

Enron Corporation Bankruptcy. As of December 2, 2001, the date of its bankruptcy filing, Enron Corporation was the counterparty to some of the Company's hedge derivative contracts, as well as purchaser of natural gas under certain physical delivery contracts. One of these contracts was a natural gas physical delivery contract with crude oil-based pricing, also referred to as the Enron Btu swap contract. The Company terminated its contracts with Enron and has recorded a net receivable of $21.3 million related to gas physical deliveries and hedge derivative fair value at the contract termination dates. An additional $14.1 million is due from Enron for net unrealized gains related to undelivered gas under physical delivery contracts, which has not been recorded in the Company's financial statements. In accordance with termination provisions of the Enron Btu swap contract, the Company believes that it no longer has a liability to Enron under this contract. However, until this debt is legally extinguished, the $43.3 million fair value liability of this contract at the date of termination must remain recorded in the Company's financial statements. In the event the termination provisions of the Enron Btu swap contract are ultimately not enforced, the Company believes that it should have the right to offset all amounts due from Enron, including amounts related to undelivered gas under physical delivery contracts, against any Enron Btu swap contract liability. Because this liability exceeds net receivables from Enron, no reserve for asset collectibility is anticipated to be necessary. The final resolution of the Enron bankruptcy and related proceedings may result in a settlement materially different from amounts recorded at December 31, 2001. See Note 7 to Consolidated Financial Statements.

Incentive Compensation. Incentive compensation results from stock appreciation right, performance share and royalty trust option awards, and subsequent changes in the Company's stock price. Incentive compensation totaled $9.6 million in 2001 and $26.1 million in 2000, which was primarily related to performance share grants, as well as royalty trust option exercises in 2000. Incentive compensation was not significant in 1999. As of December 31, 2001, there were 159,000 performance shares outstanding that vest when the common stock price reaches $18.30, 242,000 performance shares outstanding that vest when the common stock price reaches $21.67 and 13,500 performance shares that vest in increments of 6,750 in each of 2002 and 2003. In February 2002, upon vesting of the performance shares with the $18.30 common stock vesting price, an additional 159,000 performance shares were issued that vested when the stock price reached $20.00 in March 2002.

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

Oil. Crude oil prices are generally determined by global supply and demand. After OPEC members and other oil producers agreed to production cuts in March 1999, oil prices climbed through the remainder of 1999 and first quarter 2000. Despite OPEC production increases in 2000, increased demand sustained higher prices. The West Texas Intermediate ("WTI") posted price reached $34.25 per Bbl in September 2000, its highest level in ten years. Lagging demand in 2001, attributable to a worldwide economic slowdown, caused oil prices to decline. OPEC members agreed to cut daily production by one million barrels in April 2001 and an additional one million barrels in September 2001 to adjust for weak demand and excess supply. The economic decline was accelerated by the terrorist attacks in the United States on September 11, 2001, placing further downward pressure on oil prices. In December,

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OPEC announced additional production cuts of 1.5 million barrels per day effective January 1, 2002, for six months. The Company uses commodity price hedging instruments to reduce its exposure to oil price fluctuations. Excluding the effect of these hedging instruments, the Company's average oil price was $28.72 in 2000 and $17.37 in 1999. The Company did not hedge oil prices in 2001 and its average oil price was $23.49. With economic recoveries in the U.S. and global markets, oil prices have strengthened during 2002. At March 26, 2002, the average NYMEX oil price for the following 12 months was $24.91 per Bbl. The Company estimates that a $1.00 per barrel increase or decrease in the average oil sales price would result in approximately a $4.6 million change in 2002 annual operating cash flow.

Gas. Natural gas prices are dependent upon North American supply and demand, which is affected by weather conditions. Natural gas competes with alternative energy sources as a fuel for heating and the generation of electricity. The 1999 average price was lower because of high levels of gas remaining in storage from the abnormally warm winter of 1998-1999. Gas prices began to increase in May 1999 and, after declining briefly at year end, strengthened in 2000, reaching a record high of $10.10 per MMBtu in December 2000 as winter demand strained gas supplies. Gas prices declined during 2001 because of fuel switching due to higher prices, milder weather and a weaker economy, which has reduced the demand for gas to generate electricity and resulted in sharply increased gas storage levels. Despite the winter of 2001-2002 being one of the warmest on record and the likely result that storage levels will be higher than historical averages at the end of the heating season, gas prices have increased during 2002 and are expected to remain volatile. At March 26, 2002, the average NYMEX gas price for the following 12 months was $3.63 per MMBtu. The Company uses commodity price hedging instruments, including fixed price delivery contracts, to reduce its exposure to gas price fluctuations. Excluding the effect of these hedging instruments, the Company's average gas price was $3.87 in 2001, $3.70 in 2000 and $2.18 in 1999. The Company has hedges in place on approximately 95% of April through December 2002 projected production, including futures and fixed price contracts with a weighted average NYMEX price of $3.71 for 67% of production, and collars that provide a weighted average NYMEX floor price of $3.03 and ceiling price of $3.62 for 28% of production. Including the effects of gains on closed futures contracts, these collars provide a floor price of $3.31 and a ceiling price of $3.90. See summary of hedging positions at March 27, 2002, shown in table below. After the effects of hedging, the Company estimates that a $0.10 per Mcf increase or decrease in the average gas sales price would result in a $5.6 million change in 2002 annual operating cash flow, subject to floor and ceiling prices provided by the collars.

Impairment Provision. The Company regularly determines whether an impairment provision is needed for producing properties 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. The Company has not recorded impairment of producing properties since a $2 million provision was recorded in 1998. If oil and gas prices significantly decline, the Company may be required to record impairment provisions for producing properties in the future, which could be material.

Results of Operations

2001 Compared to 2000

For the year 2001, earnings available to common stock were $248.8 million compared with earnings of $115.2 million for 2000. Earnings for 2001 include a $44.6 million after-tax charge for adoption of the new derivative accounting principle, SFAS No. 133, an after-tax derivative fair value gain of $35.3 million and a $6.4 million after-tax charge for incentive compensation and loss on sale of properties. The 2000 earnings include a $7.3 million after-tax gain from the sale of Hugoton Royalty Trust units, a $13.1 million after-tax gain on sale of properties, an $8.8 million after-tax gain on investment in equity securities, a $17.3 million after-tax charge for incentive compensation and a $36.8 million after-tax derivative fair

The following summarizes the Company's April through December 2002 gas hedging positions at March 27, 2002, as are further detailed in Note 8 to the Consolidated Financial Statements. Prices to be realized for hedged production may be less than these NYMEX prices because of location, quality and other adjustments.

	Futures and Physical Contracts		Collars						Total
						Closed Contract	Adjusted		Hedged
	Mcf	NYMEX	Mcf	NYMEX Price *(b)*		Gain per	NYMEX Price *(b)(d)*		Mcf
2002 Production Period	per Day	Price *(a)*	per Day	Floor	Ceiling	Mcf *(c)*	Floor	Ceiling	per Day
April	385,050	$3.66	75,000	$2.60	$3.20	$0.48	$3.08	$3.68	460,050
May	385,050	3.66	75,000	2.60	3.20	0.45	3.05	3.65	460,050
June	335,050	3.71	150,000	2.90	3.46	0.32	3.22	3.78	485,050
2nd Quarter Average	368,566	$3.68	99,725	$2.75	$3.33	$0.39	$3.14	$3.72	468,291
July	310,000	3.73	150,000	2.95	3.52	0.31	3.26	3.83	460,000
August	310,000	3.73	150,000	2.95	3.52	0.30	3.25	3.82	460,000
September	310,000	3.73	150,000	2.95	3.52	0.30	3.25	3.82	460,000
3rd Quarter Average	310,000	$3.73	150,000	$2.95	$3.52	$0.30	$3.25	$3.82	460,000
October	310,000	3.73	165,000	3.27	3.89	0.22	3.49	4.11	475,000
November	310,000	3.73	165,000	3.27	3.89	0.18	3.45	4.07	475,000
December	310,000	3.73	165,000	3.27	3.89	0.13	3.40	4.02	475,000
4th Quarter Average	310,000	$3.73	165,000	$3.27	$3.89	$0.18	$3.45	$4.07	475,000
Nine-Month Average	329,380	$3.71	138,382	$3.03	$3.62	$0.28	$3.31	$3.90	467,762

(a) Includes $0.05 per Mcf gain that will be deferred and recognized in 2003 related to contract terminations and hedge redesignations. Physical contract prices have been converted from index to NYMEX price using estimated delivery point basis.

(b) Includes $0.10 per Mcf reduction for cost of collars.

(c) Gain on closed futures contracts per Mcf of collars. Includes average gains of $0.20 per Mcf on terminated Enron contracts.

(d) Includes gain on closed futures contracts per *(c)* above.

Management's Discussion and Analysis

value loss. Excluding these gains and losses from asset sales, changes in derivative fair value and incentive compensation, earnings for 2001 were $264.5 million, compared with $140.1 million for 2000.

Revenues for 2001 were $838.7 million, or 40% above 2000 revenues of $600.9 million. Oil revenue decreased $11.3 million, or 9%, because of a 13% decrease in oil prices from an average of $27.07 per Bbl in 2000 to $23.49 in 2001 (see "General – Product Prices – Oil" above), partially offset by a 5% increase in oil production. Increased production was primarily because of the 2001 development program.

Gas and natural gas liquids revenue increased $253.5 million, or 56%, because of a 21% increase in gas production and a 33% increase in gas prices from an average of $3.38 per Mcf in 2000 to $4.51 in 2001 (see "General – Product Prices – Gas" above). These increases were partially offset by a 1% decrease in natural gas liquids production and a 21% decrease in natural gas liquids prices from an average price of $19.61 per Bbl in 2000 to $15.41 in 2001. Increased gas production was attributable to the 2001 development program. Decreased gas liquids production was primarily because higher gas prices in first quarter 2001 made ethane extraction uneconomical at some gas plants.

Gas gathering, processing and marketing revenues decreased $3.3 million primarily because of decreased processing margins. Other revenues declined $1.1 million primarily because of decreased gains on sale of properties.

Expenses for 2001 totaled $327.8 million as compared with total 2000 expenses of $388.7 million. Excluding derivative fair value (gain) loss, expenses for 2001 totaled $382.2 million, or 15% above total expenses of $332.9 million for 2000. Most expenses increased in 2001 because of acquisitions and development and related increased production.

Production expense increased $23 million, or 26%, because of increased production, as well as higher maintenance, overhead, fuel, pumper and workover expense. Production expense per Mcfe increased $0.04. The Company's 2001 exploration expense was $5.4 million compared with $1 million for 2000 because of dry hole costs of $2.2 million and increased geological and geophysical costs.

Taxes, transportation and other deductions increased 12%, or $7 million, primarily because of increased oil and gas revenues. Taxes, transportation and other per Mcfe decreased 6% from $0.35 to $0.33 primarily because of lower severance tax rates on new wells in East Texas.

Depreciation, depletion and amortization ("DD&A") increased $24.5 million, or 19%, primarily because of increased production and higher acquisition and drilling costs. On an Mcfe basis, DD&A increased slightly from $0.79 in 2000 to $0.81 in 2001.

General and administrative expense decreased $10.2 million, or 21%, because of decreased incentive compensation of $16.5 million which was offset by increased expenses from Company growth. Excluding incentive compensation, general and administrative expense per Mcfe increased from $0.14 in 2000 to $0.15 in 2001.

The derivative fair value gain of $54.4 million in 2001 primarily reflects the effect of decreased natural gas prices during the year on the fair value of outstanding call options and a gas physical delivery contract with crude oil-based pricing. The derivative fair value loss of $55.8 million in 2000 reflects the effect of increased prices during the period on the fair value of call options. These derivatives do not qualify for hedge accounting. See Note 6 to Consolidated Financial Statements.

Interest expense decreased $23.3 million, or 30%, primarily because of a 19% decrease in the weighted average interest rate, an 11% decrease in weighted average borrowings and increased capitalized interest. Interest expense per Mcfe decreased 40% from $0.48 in 2000 to $0.29 in 2001.

2000 Compared to 1999

For the year 2000, earnings available to common stock were $115.2 million compared with earnings of $45 million for 1999. The 2000 earnings include a $7.3 million after-tax gain from the sale of Hugoton Royalty Trust units, a $13.1 million after-tax gain on sale of properties, an $8.8 million after-tax gain on investment in equity securities, a $17.3 million after-tax charge for incentive compensation and a $36.8 million after-tax loss on the change in derivative fair value. The 1999 earnings include a $26.8 million after-tax gain from the sale of Hugoton Royalty Trust units, a $4.2 million after-tax gain on sale of properties and an $800,000 after-tax loss on investment in equity securities. Excluding these gains and losses from asset sales, changes in derivative fair value and incentive compensation, earnings for 2000 were $140.1 million, compared with $14.8 million for 1999.

Revenues for 2000 were $600.9 million, or 76% above 1999 revenues of $341.3 million. Oil revenue increased $41.6 million, or 48%, because of a 60% increase in oil prices from an average of $16.94 per Bbl in 1999 to $27.07 in 2000 (see "General – Product Prices – Oil" above), partially offset by a 7% decrease in oil production. Decreased production was primarily because of the 2000 property sales.

Gas and natural gas liquids revenue increased $217.8 million, or 91%, because of a 20% increase in gas production, a 22% increase in natural gas liquids production, a 59% increase in gas prices from an average of $2.13 per Mcf in 1999 to $3.38 in 2000 and a 66% increase in natural gas liquids prices from an average price of $11.80 per Bbl in 1999 to $19.61 in 2000 (see "General – Product Prices – Gas" above). Increased gas and natural gas liquids production was attributable to the 1999 acquisitions and the 1999 and 2000 development programs.

Gas gathering, processing and marketing revenues increased $5.5 million primarily because of higher gas and natural gas liquids prices, increased margin and increased volumes from the 1999 acquisitions. Other revenues were $5.3 million lower primarily because of decreased gains on sale of properties.

Expenses for 2000 totaled $388.7 million as compared with total 1999 expenses of $245.9 million. Most expenses increased in 2000 because of the 1999 acquisitions and the 1999 and 2000 development programs.

Production expense increased $10.9 million, or 14%, because of increased production related to the 1999 acquisitions and 1999 and 2000 development programs. Production expense per Mcfe remained flat at $0.53. The Company's 2000 exploration expense of $1 million, which was predominantly geological and geophysical costs, remained about the same as 1999.

Taxes, transportation and other deductions increased 68% or $23 million because of increased oil and gas revenues, as well as increased transportation, compression and other charges related to the 1999 acquisitions and the 1999 and 2000 development programs. Taxes, transportation and other per Mcfe increased 52% from $0.23 to $0.35 because of increased prices and other deductions.

DD&A increased $17.4 million, or 16%, primarily because of the 1999 acquisitions and the 1999 and 2000 development programs. On an Mcfe basis, DD&A increased slightly from $0.78 in 1999 to $0.79.

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(continued)

General and administrative expense increased $35.4 million, or 251% because of incentive compensation of $26.1 million and increased expenses from Company growth related to the 1999 acquisitions. Excluding incentive compensation, general and administrative expense per Mcfe increased from $0.10 in 1999 to $0.14 in 2000.

Interest expense increased $14.7 million, or 23%, primarily because of a 7% increase in weighted average borrowings and an 8% increase in the weighted average interest rate. Interest classified as part of the gain (loss) on investment in equity securities decreased $4.6 million from 1999. Interest expense per Mcfe increased from $0.45 in 1999 to $0.48 in 2000.

Liquidity and Capital Resources

The Company's 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 public offerings of equity and debt. Other than for operations, the Company's 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. The Company believes that its sources of liquidity are adequate to fund its cash requirements in 2002.

Cash provided by operating activities was $542.6 million in 2001, compared with cash provided by operating activities of $377.4 million in 2000 and $133.3 million in 1999. Increased operating cash flow during this three-year period was primarily because of increased prices and production from acquisitions and development activity. Before changes in operating assets and liabilities and exploration expense, cash flow from operations was $549.6 million in 2001, $344.6 million in 2000 and $132.7 million in 1999. Operating cash flow is largely dependent upon the prices received for oil and gas production. The Company has hedged approximately 95% of its projected April through December 2002 gas production, including futures and fixed price contracts that hedge 67% of production and collars that hedge 28% of production. See "Product Prices" under "General" above.

The Company does not have any transactions, arrangements or other relationships with unconsolidated entities or persons that could materially affect its liquidity or the availability of capital resources.

Financial Condition

Total assets increased 34% from $1.6 billion at December 31, 2000 to $2.1 billion at December 31, 2001, primarily because of Company growth related to acquisitions and development. As of December 31, 2001, total capitalization was $1.7 billion, of which 51% was long-term debt. Capitalization at December 31, 2000 was $1.3 billion of which 61% was long-term debt. The decrease in the debt-to-capitalization ratio from year-end 2000 to 2001 is primarily because of increased earnings and accumulated other comprehensive income which is related to the unrealized fair value gain on hedge derivatives.

Working Capital

The Company generally maintains low cash and cash equivalent balances because it uses 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 the Company's principal source of operating cash flows (i.e., proved reserves to be produced in the following year) cannot be reported as working capital, the Company often has low or negative working capital. The increase from negative working capital of $25.3 million at December 31, 2000 to working capital of $37.5 million at December 31, 2001 was primarily attributable to the derivative fair value asset, net of deferred income taxes, recorded during 2001 related to adoption of SFAS No. 133, the new derivative accounting principle.

Financing

On December 31, 2001, borrowings under the revolving credit agreement with commercial banks were $556 million with unused borrowing capacity of $244 million. The interest rate of 3.45% at December 31, 2001 is based on the one-month London Interbank Offered Rate plus 1.375%. Based on the value of the Company's reserves, the borrowing base increased to $1.2 billion effective June 30, 2001. The banks' total commitment, however, remains at $800 million, resulting in no increase to the Company's borrowing capacity. The borrowing base is redetermined annually based on the value and expected cash flow of the Company's proved oil and gas reserves. If borrowings exceed the redetermined borrowing base, the banks may require that the excess be repaid within a year. Based on reserve values at December 31, 2001 and using parameters specified by the banks, the borrowing base remains in excess of the $800 million commitment. Borrowings under the loan agreement are due May 12, 2005, but may be prepaid at any time without penalty. The Company may renegotiate the loan agreement to increase borrowing capacity and extend the revolving facility. In February 2001, the loan agreement was amended to allow the repurchase of the Company's subordinated debt and to increase commodity hedging limits. In May 2001, the loan agreement was amended to allow the Company to issue senior debt.

The 1999 acquisitions were partially funded by the sale and issuance of common stock, cash flow from operations and contributions from Lehman, the Company's equity partner until it later purchased Lehman's interest in these acquisitions. These transactions are described under "General" above. See also "Capital Expenditures" below.

In October 2001, the Company 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 securities, preferred stock or common stock. The total price of securities to be offered is $600 million, at prices and on terms to be determined at the time of sale. Net proceeds from the sale of such securities are to be used for general corporate purposes, including reduction of bank debt. As of March 2002, no securities have been issued under the shelf registration.

Capital Expenditures

In 2001, exploration and development cash expenditures totaled $386.5 million compared with $155.4 million in 2000. The Company has budgeted $400 million for the 2002 development and exploration program. As it has done historically, the Company expects to fund the 2002 development program with cash flow from operations. Since there are no material long-term commitments associated with this budget, the Company has the flexibility to adjust its actual development expenditures in response to changes in product prices, industry conditions and the effects of the Company's acquisition and development programs.

Because of their size, the 1999 acquisitions were made jointly with Lehman as a 50% equity partner. The Company acquired Lehman's interest in the Spring Holding Acquisition in September 1999. The Company purchased Lehman's interest in the Ocean

Management's Discussion and Analysis (continued)

Energy Acquisition in March 2000 for $111 million, funded primarily by the proceeds from sales of property and equity security investments.

The Company plans to fund any future property acquisitions through a combination of cash flow from operations and proceeds from asset sales, bank debt, public equity or debt transactions. There are no restrictions under the Company's revolving credit agreement that would affect the Company's ability to use its remaining borrowing capacity for acquisitions of producing properties.

In 2000, the Board of Directors authorized the repurchase of a total of 12.4 million shares of the Company's common stock. During 2000, the Company repurchased 7.9 million shares of its common stock at a cost of $41.4 million, including 2 million shares repurchased under a 1998 Board authorization. No shares were repurchased in 2001. As of March 27, 2002, 6.5 million shares are available for repurchase.

To date, the Company has not spent significant amounts to comply with environmental or safety regulations, and it does not expect to do so during 2002. 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 from 1999 through second quarter 2000, $0.0067 per common share for third quarter 2000 through first quarter 2001 and $0.01 per common share for the remainder of 2001. The Company's ability to pay dividends is dependent upon available cash flow, as well as other factors. In addition, the Company's bank loan agreement restricts the amount of common stock dividends and treasury stock repurchases to 25% of cash flow from operations, as defined, for the last four quarters.

Contractual Obligations and Commitments

The following summarizes the Company's significant obligations and commitments to make future contractual payments as of December 31, 2001. The Company has not guaranteed the debt of any other party, nor does the Company have any other arrangements or relationships with other entities that could potentially result in unconsolidated debt.

Long-Term Debt. Borrowings under the Company's senior bank revolving credit facility were $556 million at December 31, 2001. Bank debt is not due until May 2005, but may be prepaid at any date. The Company may renegotiate its bank debt to increase borrowing capacity and extend its maturity. Subordinated debt totaled $300 million at December 31, 2001. Of that amount, $125 million is due in April 2007 and $175 million is due in November 2009. Subordinated debt may be redeemed at a price of approximately 105% in 2002. For further information regarding long-term debt, see Note 3 to Consolidated Financial Statements.

Operating Leases. The Company's minimum lease payment commitments under noncancelable lease agreements totaled $90 million at December 31, 2001. Estimated annual payments under these lease agreements for the next five years are disclosed in Note 5 to Consolidated Financial Statements. Estimated annual payments total $15.5 million for 2002 and decline for subsequent years.

Drilling Contracts. The Company has minimum drilling rig use payments of $9.5 million in 2002 and $1 million in 2003. These costs are part of the Company's budgeted capital expenditures of $400 million for 2002.

Derivative Hedge Contracts. The Company has entered into futures contracts and swaps to hedge its exposure to natural gas price fluctuations. Because the contractual fixed price generally exceeds the current market gas price, the Company expects to receive payments from counterparties under most of these contracts. If market gas prices increase, the Company could be required to make payments under these contracts, which would be funded by the higher price received from the sale of Company gas production. See Note 6 to Consolidated Financial Statements.

For further information regarding commitments, see Note 5 to Consolidated Financial Statements.

Related Party Transactions

The Company has limited related party transactions, as further disclosed in Note 2 to Consolidated Financial Statements. During 1998 and 1999, the Company loaned five of its officers $7.3 million pursuant to full recourse promissory notes to pay margin debt in broker accounts in which the officers held Company common stock. In May 2001, officers sold 302,000 shares of common stock to the Company for $6.5 million and used the proceeds to partially repay their loans. These loans were fully repaid in 2001. The interest rate charged on these loans was equal to the Company's bank debt rate.

A company, partially owned by one of the Company's directors, performs acquisition and divestiture consulting for the Company. This director-related company received consulting fees of $994,000 in 2000. It also represented the purchaser of properties sold by the Company during 1999, and also invested in the purchase. This director-related company also performed consulting services in connection with a 1998 producing property acquisition and was entitled to receive, at its election, either a 20% working interest or a 1% overriding royalty interest conveyed from the Company's 100% working interest in the properties after payout of acquisition and operating costs. The Company acquired this potential interest from the director-related company and other parties in 2001 for a price of $15 million, pursuant to an independent fairness opinion. The director-related company received $10 million of the total purchase price.

Critical Accounting Policies

The Company's financial position and results of operations are significantly affected by accounting policies and estimates related to its oil and gas properties, proved reserves, 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. The Company, which generally pursues acquisition and development of proved reserves as opposed to exploration activities, follows the successful efforts method of accounting.

Property costs must be expensed through an impairment provision if in excess of the estimated future cash flows of proved reserves. The Company evaluates possible impairment of producing properties when conditions indicate that they may be impaired. Cash flow pricing estimates are based on existing proved reserve and

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production information and pricing assumptions that management believes are reasonable. Individually significant undeveloped properties are reviewed for impairment on a property-by-property basis, and impairment of other undeveloped properties is done on a total basis. The Company's impairment of producing properties has been limited to a $2 million provision recorded in 1998. By comparison, full cost companies must generally record higher impairment provisions under a "ceiling test" which is computed using discounted estimated future after-tax cash flows based on current market prices.

Oil and Gas Reserves

The Company's 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. 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. Accordingly, oil and gas quantities ultimately recovered and the timing of production may be substantially different from original estimates.

Depreciation, depletion and amortization of producing properties is computed on the unit-of-production method based on estimated proved oil and gas reserves. If estimated proved reserves decline, future DD&A expense will increase and net income will be reduced. A decline in proved reserves also can result in a required impairment provision, as discussed under "Oil and Gas Property Accounting" above.

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.

Commodity Prices and Risk Management

Commodity prices significantly affect the Company's 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 the Company generally cannot control. Oil and gas prices and markets are expected to continue their historical volatility. See "General – Product Prices" above.

The Company attempts to reduce its price risk by entering into financial instruments such as gas futures contracts, collars and swap agreements, as well as fixed price physical delivery contracts. While these instruments guarantee a certain price and, therefore, a certain cash flow, there is the risk that the Company will not be able to realize the benefit of rising prices. These contracts also expose the Company to credit risk of non-performance by the contract counterparties, which the Company attempts to limit by obtaining letters of credit or other appropriate security. The Company also has sold call options as part of its 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.

During 2001, the Company's commodity price hedging activities resulted in a $0.64 per Mcf increase in the average gas price. During 2000, the Company's commodity price hedging activities resulted in a $0.32 per Mcf reduction in the average gas price and a $1.65 per Bbl reduction in the average oil price. Based on cash flow hedges and physical delivery contracts in place at March 27, 2002, the Company estimates that it has hedged approximately 95% of its April through December 2002 projected production, including futures and fixed price contracts that hedge 67% of production and collars that hedge 28% of production.

While the Company's price risk management activities decrease the volatility of cash flows, they may obscure the Company's operating results and financial condition. As required under generally accepted accounting principles, the Company adopted SFAS No. 133 on January 1, 2001 with a significant charge to its income statement and equity related to recording derivative financial instruments at their market value. Subsequent to that date, the Company recorded significant derivative fair value gains in the income statement and equity related to decline in natural gas prices. During 2000, the Company recorded a significant loss related to the fair value of call options. In each instance, these are projected gains and losses that will be realized upon settlement of these contracts in future periods when related production occurs. These gains and losses are offset by increases and decreases in the market value of the Company's proved reserves, which are not reflected in the financial statements. Also, a significant portion of the Company's gas price hedging is provided by fixed price physical delivery contracts which had a fair value of $36.4 million at December 31, 2001. This asset is not recorded in the Company's financial statements since the contracts are deemed to be normal sales that are not expected to be net cash settled, and therefore are not derivatives. Derivatives that provide effective cash flow hedges are designated as hedges and the Company defers related fair value gains and losses in accumulated other comprehensive income until the hedged transaction occurs. Because hedge accounting is not required under generally accepted accounting principles, the Company's operating results as reflected in its financial statements may not be comparable to other companies.

See "Commodity Price Risk" for the effect of price changes on derivative fair value gains and losses.

Accounting Pronouncements

During 2001, the Financial Accounting Standards Board issued the following Statements of Financial Accounting Standards:

- SFAS No. 141, *Business Combinations*, requires the use of the purchase method of accounting, as opposed to the pooling-of-interests method, for all business combinations initiated or completed after June 30, 2001. It supersedes APB Opinion No. 16, *Business Combinations*, and SFAS No. 38, *Accounting for Preacquisition Contingencies of Purchased Enterprises*. The adoption of SFAS No. 141 should have no material affect on the Company's financial statements since it has historically used the purchase method of accounting to record business combinations.
- SFAS No. 142, *Goodwill and Other Intangible Assets*, changes the method of accounting for acquired goodwill and other tangible assets, and supersedes APB Opinion No. 17, *Intangible Assets*. Goodwill and intangible assets with indefinite lives will no longer be amortized and will be tested

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at least annually for impairment. The provisions of SFAS No. 142 are required to be applied to fiscal years beginning after December 15, 2001 and should not have a material effect on the Company's financial statements.

- SFAS No. 143, *Accounting for Asset Retirement Obligations*, amends SFAS No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies*, and addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. It requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The associated asset retirement costs are capitalized as part of the cost of the long-lived asset. The statement is required to be adopted for fiscal years beginning after June 15, 2002. The effect of the Company's adoption of SFAS No. 143 has not been determined but is currently not expected to be material.
- SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, supersedes SFAS No. 121, *Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed of.* With this pronouncement, the FASB establishes a single accounting model for long-lived assets to be disposed of by sale, including the reporting of discontinued operations. The statement is required to be adopted for fiscal years beginning after December 15, 2001. The effect of the Company's adoption of SFAS No. 144 has not been determined but is currently not expected to be material.

Production Imbalances

The Company has 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. The Company uses the entitlement method of accounting for natural gas sales. Accordingly, revenue is deferred for gas deliveries in excess of the Company's 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			
(in thousands)	2001		2000	
	Amount	Mcf	Amount	Mcf
Accounts receivable – current underproduction	$ 13,497	5,079	$ 11,185	4,854
Accounts payable – current overproduction	(13,064)	(4,871)	(8,720)	(3,943)
Net current gas underproduction balancing receivable	$ 433	208	$ 2,465	911
Other assets – noncurrent underproduction	$ 15,763	6,018	$ 11,208	5,133
Other long-term liability – noncurrent overproduction	(21,871)	(8,164)	(19,216)	(8,714)
Net long-term gas overproduction balancing payable	(6,108)	(2,146)	(8,008)	(3,581)
Other assets – noncurrent carbon dioxide underproduction	4,165	11,256	4,327	10,062
Net long-term overproduction balancing payable	$ (1,943)		$ (3,681)	

Forward-Looking Statements

Certain information included in this annual report and other materials filed or to be filed by the Company with the Securities and Exchange Commission, as well as information included in oral statements or other written statements made or to be made by the Company, 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 the Company's operations and the oil and gas industry. Such forward-looking statements may be or may concern, among other things, capital expenditures, cash flow, drilling activity, acquisition and development activities, pricing differentials, operating costs, production activities, oil, gas and natural gas liquids reserves and prices, hedging activities and the results thereof, liquidity, debt repayment, 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.

Among the factors that could cause actual results to differ materially are:

- crude oil and natural gas price fluctuations,
- changes in interest rates,
- the Company's ability to acquire oil and gas properties that meet its objectives and to identify prospects for drilling,
- higher than expected production costs and other expenses,
- potential delays or failure to achieve expected production from existing and future exploration and development projects,
- volatility of crude oil and natural gas prices and related financial derivatives,
- basis risk and counterparty credit risk in executing commodity price risk management activities,
- potential liability resulting from pending or future litigation, and
- competition in the oil and gas industry as well as competition from other sources of energy.

In addition, these forward-looking statements may be affected by general domestic and international economic and political conditions.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Company only enters derivative financial instruments in conjunction with its hedging activities. These instruments principally include interest rate swap agreements and commodity futures, collars, swaps and option 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.

The Board of Directors has adopted a policy governing the use of derivative instruments, which requires that all derivatives used by the Company 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 or the Executive Vice President – Administration of all risk management programs using derivatives and all derivative transactions. These programs are also reviewed at least 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

The Company is exposed to interest rate risk on short-term and long-term debt carrying variable interest rates. At December 31, 2001, the Company's variable rate debt had a carrying value of $556 million, which approximated its fair value, and the Company's fixed rate debt had a carrying value of $300 million and an approximate fair value of $314.7 million. The Company attempts 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 subordinated debt, as well as the use of interest rate swaps.

The following table shows the carrying amount and fair value of long-term debt and interest rate swaps, 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	Hypothetical Change in Fair Value
December 31, 2001			
Long-term debt	$(856,000)	$(870,720)	$14,874 *(a)*
Interest rate swaps	2,791	2,791	(809)*(a)*
December 31, 2000			
Long-term debt	$(769,000)	$(774,000)	$16,389
Interest rate swaps	473	2,651	1,484

(a) This is approximate gain in fair value of long-term debt and loss in fair value of interest rate swaps from a 100-basis point increase in interest rates. Because of the limitation in value caused by the 2002 call price of the Company's fixed rate debt, a 100-basis point decrease in interest rates would not significantly affect fair value at December 31, 2001.

Commodity Price Risk

The Company hedges a portion of its price risks associated with its crude oil and natural gas sales. As of December 31, 2001, the Company had outstanding gas futures contracts, swap agreements and gas basis swap agreements. These contracts and agreements had a net fair value gain of approximately $97.6 million at December 31, 2001 and a net fair value loss of $108.9 million at December 31, 2000. Of the December 31, 2001 fair value, a $98.4 million gain has been determined based on the exchange-trade value of NYMEX contracts and an $800,000 loss 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 $27.8 million in the fair value of gas futures contracts and swap agreements at December 31, 2001. This sensitivity does not include physical product delivery contracts, which are not expected to be settled in cash or another financial instrument; these contracts had a fair value gain of $36.4 million at December 31, 2001. See Note 8 to Consolidated Financial Statements.

Because these futures contracts and swap agreements are designated hedge derivatives, changes in their fair value are reported as a component of accumulated other comprehensive income 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.

In conjunction with its hedging activities, the Company sold call options to sell future gas production at certain ceiling prices. Call options outstanding had a fair value loss of $44.2 million at December 31, 2000. All call options were settled in 2001 with payments to the counterparties totaling $14.7 million, resulting in a 2001 derivative fair value gain of $29.5 million.

The Company 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 under SFAS No. 133 beginning January 1, 2001. This contract (referred to as the Enron Btu swap contract) was terminated in December 2001 in conjunction with the bankruptcy filing of Enron Corporation, and as a result, the Company believes that its liability under this contract was reduced to zero. A $43.3 million current liability will remain on the Company's consolidated balance sheet until this contractual liability is legally extinguished. See Note 7 to Consolidated Financial Statements and "General – Enron Corporation Bankruptcy" above.

In November 2001, the Company 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, 2001 was $4.1 million. Of this fair value, a $6.1 million gain has been determined based on the exchange-trade value of NYMEX contracts, and a $10.2 million loss has been based on Company estimated oil prices for periods beyond 2004 for which there are not readily available exchange-trade values. These values approximate amounts confirmed by the counterparty. The effect of a hypothetical 10% change in gas prices would result in a change of approximately $350,000 in the fair value of these contracts, while a 10% change in crude oil prices would result in a change of approximately $150,000. In March 2002, the Company terminated contracts with maturities of May through December 2002 and received $6.6 million from the counterparty. Because these contracts are non-hedge derivatives, most of the related $6.6 million gain related to their termination was recorded in 2001 derivative fair value gain.

Consolidated Balance Sheets

(in thousands, except shares)	December 31 2001	December 31 2000
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 6,810	$ 7,438
Accounts receivable, net	111,101	158,826
Derivative fair value	107,526	106
Deferred income tax benefit	—	17,098
Other current assets	13,930	9,969
Total Current Assets	239,367	193,437
Property and Equipment, at cost — successful efforts method:		
Producing properties	2,352,473	1,732,017
Undeveloped properties	9,545	6,460
Other	50,645	38,340
Total Property and Equipment	2,412,663	1,776,817
Accumulated depreciation, depletion and amortization	(571,276)	(419,443)
Net Property and Equipment	1,841,387	1,357,374
Other Assets:		
Derivative fair value	18,174	367
Loans to officers	—	8,214
Other	33,399	32,512
Total Other Assets	51,573	41,093
TOTAL ASSETS	$2,132,327	$1,591,904

	2001	2000
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 125,486	$ 153,581
Payable to royalty trusts	2,233	8,577
Derivative fair value	1,024	44,189
Enron Btu swap contract	43,272	—
Current income taxes payable	600	—
Deferred income taxes payable	27,330	—
Other current liabilities	1,898	12,404
Total Current Liabilities	201,843	218,751
Long-term Debt	856,000	769,000
Other Long-term Liabilities:		
Derivative fair value	28,331	—
Deferred income taxes payable	199,091	82,476
Other long-term liabilities	26,012	24,310
Total Other Long-term Liabilities	253,434	106,786
Commitments and Contingencies (Note 5)		
Stockholders' Equity:		
Series A convertible preferred stock ($.01 par value, 25,000,000 shares authorized, -0- and 1,088,663 issued at liquidation value of $25)	—	27,217
Common stock ($.01 par value, 250,000,000 shares authorized, 131,988,733 and 123,880,245 shares issued)	1,320	1,239
Additional paid-in capital	485,094	435,322
Treasury stock (8,215,998 and 7,546,560 shares)	(64,714)	(50,829)
Retained earnings	328,712	84,418
Accumulated other comprehensive income	70,638	—
Total Stockholders' Equity	821,050	497,367
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$2,132,327	$1,591,904

See accompanying notes to consolidated financial statements.

Consolidated Income Statements

(in thousands, except per share data)	Year Ended December 31 2001	2000	1999
REVENUES			
Oil and condensate	$116,939	$128,194	$ 86,604
Gas and natural gas liquids	710,348	456,814	239,056
Gas gathering, processing and marketing	12,832	16,123	10,644
Other	(1,371)	(280)	4,991
Total Revenues	838,748	600,851	341,295
EXPENSES			
Production	110,005	86,988	76,110
Taxes, transportation and other	63,656	56,696	33,681
Exploration	5,438	1,047	904
Depreciation, depletion and amortization	154,322	129,807	112,364
Gas gathering and processing	9,522	8,930	8,743
General and administrative	39,217	49,460	14,091
Derivative fair value (gain) loss	(54,370)	55,821	—
Total Expenses	327,790	388,749	245,893
OPERATING INCOME	510,958	212,102	95,402
OTHER INCOME (EXPENSE)			
Gain on significant property divestitures	—	29,965	40,566
Gain (loss) on investment in equity securities	—	13,279	(1,149)
Interest expense, net	(55,601)	(78,914)	(64,214)
Total Other Income (Expense)	(55,601)	(35,670)	(24,797)
INCOME BEFORE INCOME TAX, MINORITY INTEREST AND CUMULATIVE EFFECT OF ACCOUNTING CHANGE	455,357	176,432	70,605
Income tax expense	161,952	59,380	23,965
Minority interest in net (income) loss of consolidated subsidiaries	—	(59)	103
NET INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	293,405	116,993	46,743
Cumulative effect of accounting change, net of tax	(44,589)	—	—
NET INCOME	248,816	116,993	46,743
Preferred stock dividends	—	1,758	1,779
EARNINGS AVAILABLE TO COMMON STOCK	$248,816	$115,235	$ 44,964
EARNINGS PER COMMON SHARE			
Basic:			
Net income before cumulative effect of accounting change	$ 2.39	$ 1.08	$ 0.43
Cumulative effect of accounting change	(0.36)	—	—
Earnings available to common stock	$ 2.03	$ 1.08	$ 0.43
Diluted:			
Net income before cumulative effect of accounting change	$ 2.35	$ 1.03	$ 0.42
Cumulative effect of accounting change	(0.35)	—	—
Earnings available to common stock	$ 2.00	$ 1.03	$ 0.42
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING	122,505	106,730	105,341

See accompanying notes to consolidated financial statements.

Consolidated Statements of Cash Flows

(in thousands)	Year Ended December 31 2001	2000	1999
OPERATING ACTIVITIES			
Net income	$ 248,816	$ 116,993	$ 46,743
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	154,322	129,807	112,364
Non-cash incentive compensation	9,246	25,790	93
Deferred income tax	161,105	58,993	23,657
(Gain) loss on investment in equity securities and from sale of properties	277	(45,578)	(51,802)
Non-cash (gain) loss in derivative fair value	(69,147)	54,512	—
Minority interest in net income (loss) of consolidated subsidiaries	—	59	(103)
Cumulative effect of accounting change, net of tax	44,589	—	—
Other non-cash items	(5,079)	3,015	827
Changes in operating assets and liabilities *(a)*	(1,514)	33,830	1,522
Cash Provided by Operating Activities	542,615	377,421	133,301
INVESTING ACTIVITIES			
Proceeds from sale of Hugoton Royalty Trust units	—	—	148,570
Proceeds from sale of other property and equipment	319	77,119	110,500
Property acquisitions	(224,906)	(45,648)	(270,226)
Purchase of Spring Holding Company	—	—	(42,540)
Development costs	(381,026)	(154,382)	(90,725)
Other property additions	(13,438)	(11,033)	(10,479)
(Loans to) repayments from officers	8,128	60	(1,470)
Cash Used by Investing Activities	(610,923)	(133,884)	(156,370)
FINANCING ACTIVITIES			
Proceeds from short- and long-term debt	640,000	523,400	256,400
Payments on short- and long-term debt	(553,000)	(745,500)	(339,262)
Dividends	(4,413)	(3,891)	(4,950)
Purchase of minority interest	—	(100,071)	(42,385)
Contributions from minority interests	—	—	142,500
Common stock offering	—	126,125	29,668
Purchases of treasury stock and other	(14,907)	(41,896)	(25,501)
Cash Provided (Used) by Financing Activities	67,680	(241,833)	16,470
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(628)	1,704	(6,599)
Cash and Cash Equivalents, January 1	7,438	5,734	12,333
Cash and Cash Equivalents, December 31	$ 6,810	$ 7,438	$ 5,734
(a) **Changes in Operating Assets and Liabilities**			
Accounts receivable	$ 58,706	$ (90,921)	$ (8,227)
Investment in equity securities	—	43,746	20,180
Other current assets	(3,855)	(4,535)	(32)
Other assets	(1,738)	(15,535)	—
Current liabilities	(54,627)	82,392	(11,628)
Other long-term liabilities	—	18,683	1,229
	$ (1,514)	$ 33,830	$ 1,522

See accompanying notes to consolidated financial statements.

Consolidated Statements of Stockholders' Equity

(in thousands, except per share amounts)	Preferred Stock	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Earnings (Deficit)	Accumulated Other Comprehensive Income	Total
Balances, December 31, 1998	$28,468	$1,216	$361,851	$(118,555)	$ (71,506)	$ —	$201,474
Net income	—	—	—	—	46,743	—	46,743
Issuance/sale of common stock	—	90	45,610	—	—	—	45,700
Issuance/vesting of performance shares	—	3	230	—	—	—	233
Stock option exercises	—	—	95	(755)	—	—	(660)
Treasury stock purchases	—	—	—	(25,517)	—	—	(25,517)
Treasury stock issued	—	—	(11,945)	25,440	—	—	13,495
Common stock dividends ($0.018 per share)	—	—	—	—	(1,872)	—	(1,872)
Preferred stock dividends ($1.56 per share)	—	—	—	—	(1,779)	—	(1,779)
Balances, December 31, 1999	28,468	1,309	395,841	(119,387)	(28,414)	—	277,817
Net income	—	—	—	—	116,993	—	116,993
Sale of common stock from treasury	—	—	61,427	64,698	—	—	126,125
Issuance/vesting of performance shares	—	12	18,240	(6,976)	—	—	11,276
Stock option exercises	—	48	29,960	(4,933)	—	—	25,075
Treasury stock purchases	—	—	—	(55,758)	—	—	(55,758)
Cancellation of shares	—	(133)	(71,394)	71,527	—	—	—
Common stock dividends ($0.022 per share)	—	—	—	—	(2,403)	—	(2,403)
Preferred stock converted to common	(1,251)	3	1,248	—	—	—	—
Preferred stock dividends ($1.56 per share)	—	—	—	—	(1,758)	—	(1,758)
Balances, December 31, 2000	27,217	1,239	435,322	(50,829)	84,418	—	497,367
Net income	—	—	—	—	248,816	—	248,816
Cumulative effect of change in accounting for hedge derivatives net of applicable income tax benefit of $36,251	—	—	—	—	—	(67,323)	(67,323)
Change in hedge derivative fair value, net of applicable taxes of $69,153	—	—	—	—	—	128,428	128,428
Hedge derivative contract settlements reclassified into earnings from other comprehensive income, net of applicable taxes of $5,133	—	—	—	—	—	9,533	9,533
Comprehensive income	—	—	—	—	—	—	319,454
Issuance/vesting of performance shares	—	7	5,184	(4,226)	—	—	965
Stock option exercises	—	21	17,424	(410)	—	—	17,035
Treasury stock purchases	—	—	—	(9,249)	—	—	(9,249)
Common stock dividends ($0.037 per share)	—	—	—	—	(4,522)	—	(4,522)
Preferred stock converted to common	(27,217)	53	27,164	—	—	—	—
Balances, December 31, 2001	$ —	$1,320	$485,094	$ (64,714)	$328,712	$ 70,638	$821,050

See accompanying notes to consolidated financial statements.

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 its wholly owned subsidiaries ("the Company"). 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 three-for-two stock splits effected on September 18, 2000 and June 5, 2001.

The Company is an independent oil and gas company with production and exploration concentrated in Texas, Oklahoma, Arkansas, Kansas, New Mexico, Wyoming, Alaska and Louisiana. The Company also gathers, processes and markets gas, transports and markets oil and conducts other activities directly related to its oil and gas producing activities.

Property and Equipment

The Company follows 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. The Company generally pursues acquisition and development of proved reserves as opposed to exploration activities. Most 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 $136,611,000 at December 31, 2001 and $66,823,000 at December 31, 2000, related to wells in process of drilling.

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. The estimated undiscounted cost, net of salvage value, of dismantling and removing major oil and gas production facilities, including necessary site restoration, is accrued using the unit-of-production method.

If conditions indicate that long-term assets may be impaired, the carrying value of property and equipment is compared to management's future estimated pre-tax cash flow. If impairment is necessary, the asset carrying value is adjusted 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.

Royalty Trusts

The Company created Cross Timbers Royalty Trust in February 1991 and Hugoton Royalty Trust in December 1998 by conveying defined net profits interests in certain of the Company's properties. Units of both trusts are traded on the New York Stock Exchange. The Company makes monthly net profits payments to each trust based on revenues and costs from the related underlying properties. The Company owns 22.7% of Cross Timbers Royalty Trust units that it purchased on the open market in 1996 and 1997, and owns 54.3% of the Hugoton Royalty Trust following the sale of units in 1999 and 2000. The cost of the Company's interest in the trusts is included in producing properties. Amounts due the trusts, net of amounts retained by the Company's ownership of trust units, are deducted from the Company's 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.

Investment in Equity Securities

In accordance with Statement of Financial Accounting Standards ("SFAS") No. 115, *Accounting for Certain Investments in Debt and Equity Securities*, equity securities held during 1999 and 2000 were recorded as trading securities since they were acquired principally for resale in the near future. Accordingly, unrealized holding gains and losses are recognized in the consolidated income statements, and cash flows from purchases and sales of equity securities are included in cash provided by operating activities in the consolidated statements of cash flows. Gains (losses) on trading securities and interest expense related to the cost of these investments are classified as other income (expense) in the consolidated income statements.

Other Assets

Other assets primarily include deferred debt costs that are amortized over the term of the related debt (Note 3) and the long-term portion of gas balancing receivable (see "Revenue Recognition" below). Other assets are presented net of accumulated amortization of $16,194,000 at December 31, 2001 and $11,574,000 at December 31, 2000.

Derivatives

The Company uses derivatives to hedge product price and interest rate risks, as opposed to their use for trading purposes. On January 1, 2001, the Company adopted SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended by SFAS Nos. 137 and 138 (Note 6). SFAS No. 133 requires the Company to record all derivatives on the balance sheet at fair value. Change in the fair value of derivatives that are not designated as hedges, as well as the ineffective portion of hedge derivatives, must be recognized as a derivative fair value gain or loss in the income statement. Changes in the fair value of effective cash flow hedges are recorded as a component of accumulated other comprehensive income, which is later transferred to earnings when the hedged transaction occurs. Physical delivery contracts which 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).

Gains and losses on commodity hedge derivatives are recognized in oil and gas revenues when the hedged transaction occurs, and gains and losses on interest hedge derivatives are recorded as adjustments to interest expense. Cash flows related to derivative transactions are included in operating activities.

In conjunction with its hedging activities, the Company occasionally enters natural gas call options. Because 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 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.

Revenue Recognition

The Company uses the entitlement method of accounting for gas sales, based on the Company's net revenue interest in production. Accordingly, revenue is deferred for gas deliveries in excess of the Company's 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

Notes to Consolidated Financial Statements

time of production. The consolidated balance sheets include the following amounts related to production imbalances:

	December 31			
(in thousands)	2001		2000	
	Amount	Mcf	Amount	Mcf
Accounts receivable – current underproduction	$ 13,497	5,079	$ 11,185	4,854
Accounts payable – current overproduction	(13,064)	(4,871)	(8,720)	(3,943)
Net current gas underproduction balancing receivable	$ 433	208	$ 2,465	911
Other assets – noncurrent underproduction	$ 15,763	6,018	$ 11,208	5,133
Other long-term liability – noncurrent overproduction	(21,871)	(8,164)	(19,216)	(8,714)
Net long-term gas overproduction balancing payable	(6,108)	(2,146)	(8,008)	(3,581)
Other assets – noncurrent carbon dioxide underproduction	4,165	11,256	4,327	10,062
Net long-term overproduction balancing payable	$ (1,943)		$ (3,681)	

Gas Gathering, Processing and Marketing Revenues

Gas produced by the Company and third parties is marketed by the Company 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 $108,590,000 for 2001, $144,282,000 for 2000 and $66,175,000 for 1999. These amounts are net of intercompany eliminations.

Other Revenues

Other revenues include gains and losses from sale of property and equipment. Excluding the gain on sale of significant property divestitures, including the sale of Hugoton Royalty Trust units, the Company realized a net loss on sale of property and equipment of $277,000 in 2001, and a net gain on sale of property and equipment of $920,000 in 2000 and $6,390,000 in 1999.

Interest

Interest expense includes amortization of deferred debt costs and is presented net of interest income of $716,000 in 2001, $1,430,000 in 2000 and $619,000 in 1999, and net of capitalized interest of $6,649,000 in 2001, $3,488,000 in 2000 and $1,353,000 in 1999. Interest is capitalized as producing property cost based on the weighted average interest rate and the cost of wells in process of drilling. Interest expense related to investment in equity securities has been classified as a component of gain (loss) on investment in equity securities.

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 when the price target is reached. 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*, is disclosed in Note 12.

Earnings per Common Share

In accordance with SFAS No. 128, *Earnings Per Share*, the Company reports basic earnings per share, which excludes the effect of potentially dilutive securities, and diluted earnings per 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*, the Company has identified only one operating segment, which is the exploration and production of oil and gas. All the Company's assets are located in the United States and all its revenues are attributable to United States customers.

Production is sold under contracts with various purchasers. For the year ended December 31, 2001, sales to each of three purchasers were approximately 13%, 12% and 10% of total revenues. For the year ended December 31, 2000, sales to a single purchaser were approximately 13% of total revenues. There were no sales to a single purchaser that exceeded 10% of total revenues in 1999. The Company believes that alternative purchasers are available, if necessary, to purchase production at prices substantially similar to those received from these significant purchasers.

2. Related Party Transactions

Loans to Officers

Pursuant to margin support agreements with each of six officers, the Company, with Board of Director authorization, agreed to use up to $15 million of the value of Cross Timbers Royalty Trust units owned by the Company and the investment in equity securities to provide margin support for the officers' broker accounts in which they held Company common stock. The Company also agreed to pay, if necessary, each officer's margin debt in the event the officer subsequently failed to satisfy the debt. In connection with these agreements, in December 1998 the Company loaned four officers a total of $5,795,000 to reduce their margin debt. An additional $1,530,000 was loaned during 1999, including a new loan to a fifth officer. The loans were full recourse and due in December 2003, with an interest rate equal to the Company's bank debt rate. In May 2001, officers sold 302,000 shares of common stock to the Company for $6,496,000 and used the proceeds to partially repay their loans. Loans to officers were fully repaid in November 2001.

Other Transactions

A company, partially owned by a director of the Company, received fees totaling $994,000 in 2000 for consulting services performed in connection with the Company's acquisition and divestiture programs. The director-related company also represented the purchaser of properties sold by the Company during 1999 and invested in the purchase.

The same director-related company performed consulting services in connection with a 1998 acquisition and was entitled to receive, at its election, either a 20% working interest or a 1% overriding royalty interest conveyed from the Company's 100% working interest in the properties after payout of acquisition and operating costs. The Board of Directors authorized the purchase of this potential interest from the director-related company and other parties in November 2001 for $15 million, as supported by a third-party fairness opinion. The director-related company received $10 million of the total purchase price.

3. Debt

The Company's outstanding debt consists of the following:

	December 31	
(in thousands)	2001	2000
Long-term Debt:		
Senior debt –		
Bank debt under revolving credit agreements due May 12, 2005, 3.45% at December 31, 2001	$556,000	$469,000
Subordinated debt –		
9¼% senior subordinated notes due April 1, 2007	125,000	125,000
8¼% senior subordinated notes due November 1, 2009	175,000	175,000
Total long-term debt	$856,000	$769,000

Notes to Consolidated Financial Statements

(continued)

Senior Debt

In May 2000, the Company entered a revolving credit agreement with commercial banks with a commitment of $800 million. In June 2000, the loan agreement was amended to allow the Company to issue letters of credit. Any letters of credit outstanding reduce the borrowing capacity under the revolving credit facility. As of December 31, 2001, there were no letters of credit outstanding. In February 2001, the loan agreement was amended to allow the repurchase of the Company's subordinated debt and to increase commodity hedging limits. In May 2001, the loan agreement was amended to allow the Company to issue senior debt. Borrowings at December 31, 2001 under the loan agreement were $556 million with unused borrowing capacity of $244 million. The borrowing base is redetermined annually based on the value and expected cash flow of the Company's proved oil and gas reserves. If borrowings exceed the redetermined borrowing base, the banks may require that the excess be repaid within a year. Based on reserve values at December 31, 2001 and using parameters specified by the banks, the borrowing base remains in excess of the $800 million commitment. Borrowings under the loan agreement are due May 12, 2005, but may be prepaid at any time without penalty. The Company may renegotiate the loan agreement to increase the borrowing commitment and extend the revolving facility.

The credit facility is partially secured by the Company's producing properties. Restrictions set forth in the loan agreement include limitations on the incurrence of additional indebtedness and the creation of certain liens. The loan agreement also limits dividends to 25% of cash flow from operations, as defined, for the latest four consecutive quarterly periods. The Company is also required to maintain a current ratio of not less than one (where unused borrowing commitments are included as a current asset and current assets and liabilities related to derivative fair value are excluded).

The loan agreement provides the option of borrowing at floating interest rates based on the prime rate or at fixed rates for periods of up to six months based on certificate of deposit rates or London Interbank Offered Rates ("LIBOR"). Borrowings under the loan agreement at December 31, 2001 were based on LIBOR rates with maturity of one to six months and accrued at the applicable LIBOR rate plus 1.375%. Interest is paid at maturity, or quarterly if the term is for a period of 90 days or more. The Company also incurs a commitment fee on unused borrowing commitments which was 0.25% at December 31, 2001. The weighted average interest rate on senior debt was 5.7% during 2001, 8.2% during 2000 and 6.7% during 1999.

Subordinated Debt

The Company sold $125 million of 9¼% senior subordinated notes on April 2, 1997, and $175 million of 8¾% senior subordinated notes on October 28, 1997. The notes are general unsecured indebtedness that is subordinate to bank borrowings under the loan agreement. Net proceeds of $121.1 million from the 9¼% notes and $169.9 million from the 8¾% notes were used to reduce bank borrowings under the loan agreement. The 9¼% notes mature on April 1, 2007 and interest is payable each April 1 and October 1, while the 8¾% notes mature on November 1, 2009 with interest payable each May 1 and November 1.

The Company has the option to redeem the 9¼% notes on April 1, 2002 and the 8¾% notes on November 1, 2002 at a price of approximately 105%, and thereafter at prices declining ratably at each anniversary to 100% in 2005. Upon a change in control of the Company, the noteholders have the right to require the Company to purchase all or a portion of their notes at 101% plus accrued interest.

The notes were issued under indentures that place certain restrictions on the Company, including limitations on additional indebtedness, liens, dividend payments, treasury stock purchases, disposition of proceeds from asset sales, transfers of assets and transactions with subsidiaries and affiliates.

See Note 6 regarding interest rate swap agreements. Under the terms of one of these agreements, the Company has notified the bank counterparty that it will purchase subordinated notes with a face value of $9,725,000 on April 1, 2002. Including the effects of the interest swap agreement and expensing of related deferred debt cost, the Company will record a loss on extinguishment of debt of approximately $600,000.

4. Income Tax

The effective income tax rate for the Company was different than the statutory federal income tax rate for the following reasons:

(in thousands)	2001	2000	1999
Income tax expense at the federal statutory rate (35% in 2001, and 34% in 2000 and 1999)	$159,375	$59,987	$24,006
State and local taxes and other	2,577	(607)	(41)
Income tax expense	$161,952	$59,380	$23,965

Components of income tax expense are as follows:

(in thousands)	2001	2000	1999
Current income tax	$ 847	$ 387	$ 308
Deferred income tax expense	155,021	63,792	28,697
Net operating loss carryforwards (added) used	6,084	(4,799)	(5,040)
Income tax expense	$161,952	$59,380	$ 23,965

Deferred tax assets and liabilities are the result of temporary differences between the financial statement carrying values and tax bases of assets and liabilities. The Company's net deferred tax liabilities are recorded as a current liability of $27,330,000 and a long-term liability of $199,091,000 at December 31, 2001, and a current asset of $17,098,000 and a long-term liability of $82,476,000 at December 31, 2000. Significant components of net deferred tax assets and liabilities are:

	December 31	
(in thousands)	2001	2000
Deferred tax assets:		
Net operating loss carryforwards	$ 63,286	$ 69,370
Accrued stock appreciation right and performance share compensation	17	916
Derivative fair value loss	25,940	15,024
Other	5,976	5,038
Total deferred tax assets	95,219	90,348
Deferred tax liabilities:		
Property and equipment	261,353	148,363
Derivative fair value gain	48,646	—
Other	11,641	7,363
Total deferred tax liabilities	321,640	155,726
Net deferred tax liabilities	$(226,421)	$(65,378)

As of December 31, 2001, the Company has estimated tax loss carryforwards of approximately $195 million, of which $10.6 million are related to capital losses. The capital loss tax carryforwards expire in 2005 while the remaining ordinary loss carryforwards are scheduled to expire in 2009 through 2021. Approximately $22 million of the tax loss carryforwards are the result of an acquisition. A new tax law, signed in March 2002 and retroactive to September 11, 2001, will increase the Company's tax loss carryforwards by approximately $12 million. The Company has not booked any valuation allowance because it believes it has tax planning strategies available to realize its tax loss carryforwards.

5. Commitments and Contingencies

Leases

The Company leases offices, vehicles, airplanes, compressors and certain other equipment in its 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, 2001, minimum future lease payments for all noncancelable lease agreements (including the sale and operating leaseback agreements described below) were as follows:

(in thousands)	
2002	$15,524
2003	14,956
2004	10,411
2005	8,539
2006	8,639
Remaining	31,898
Total	$89,967

Notes to Consolidated Financial Statements

Amounts incurred under operating leases (including renewable monthly leases) were $20,561,000 in 2001, $17,329,000 in 2000 and $14,093,000 in 1999.

In March 1996, the Company sold its 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 November 1996, the Company sold its 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. Rentals are adjusted monthly based on the 30-day LIBOR rate and may be irrevocably fixed by the Company with 20 days advance notice. As of December 31, 2001, annual rentals were $1.6 million. 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, 2001 was $1.6 million.

Under each of the above sale and leaseback transactions, the Company does 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 the Company at its fair market value. Additionally, the Company has a right of first refusal of any third party offers to buy the facility after the initial term.

Employment Agreements

Two executive officers have year-to-year employment agreements with the Company. 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, the Company terminates 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. 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

The Company has entered into natural gas physical delivery contracts, futures contracts, collars and swap agreements that effectively fix gas prices. See Note 8.

Drilling Contracts

The Company has agreements to use four drilling rigs and one workover rig through July 2003. Total commitments under these agreements are $9.5 million for 2002 and $1 million for 2003.

Litigation

On April 3, 1998, a class action lawsuit, styled *Booth, et al. v. Cross Timbers Oil Company*, was filed against the Company in the District Court of Dewey County, Oklahoma. The action was filed on behalf of all persons who, at any time since June 1991, have been paid royalties on gas produced from any gas well within the State of Oklahoma under which the Company has assumed the obligation to pay royalties. The plaintiffs allege that the Company has reduced royalty payments by post-production deductions and has entered into contracts with subsidiaries that were not arm's-length transactions. The plaintiffs further allege that these actions reduced the royalties paid to the plaintiffs and those similarly situated, and that such actions are a breach of the leases under which the royalties are paid. These deductions allegedly include production and post-production costs, marketing costs, administration costs and costs incurred by the Company in gathering, compressing, dehydrating, processing, treating, blending and/or transporting the gas produced. The Company contends that, to the extent any fees are proportionately borne by the plaintiffs, these fees are established by arm's-length negotiations with third parties or, if charged by affiliates, are comparable to fees charged by third party gatherers or processors. The Company further contends that any such fees enhance the value of the gas or the products derived from the gas. The plaintiffs are seeking an accounting and payment of the monies allegedly owed to them. A hearing on the class certification issue has not been scheduled. The court has ordered that the parties enter into mediation, which should occur in the first half of 2002. Management believes it has strong defenses against this claim and intends to vigorously defend the action. Management's estimate of the potential liability from this claim has been accrued in the Company's financial statements.

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 against the Company and certain of its subsidiaries by Jack J. Grynberg on behalf of the United States under the *qui tam* provisions of the False Claims Act. The plaintiff alleges that the Company underpaid royalties on gas produced from federal leases and lands owned by Native Americans by at least 20% during the past 10 years as a result of mismeasuring the volume of gas and incorrectly analyzing its heating content. According to the U.S. Department of Justice, the plaintiff has made similar allegations in over 70 actions filed against more than 300 other companies. The plaintiff seeks to recover the amount of royalties not paid, together with treble damages, a civil penalty of $5,000 to $10,000 for each violation and attorney fees and expenses. The plaintiff also seeks an order for the Company to cease the allegedly improper measuring practices. After its review, the Department of Justice decided in April 1999 not to intervene and asked the court to unseal the case. The court unsealed the case in May 1999. A multi-district litigation panel ordered that the lawsuits against the Company and other companies filed by Grynberg be transferred and consolidated to the federal district court in Wyoming. The Company and other defendants filed a motion to dismiss the lawsuit, which was denied. The Company believes that the allegations of this lawsuit are without merit and intends to vigorously defend the action. Any potential liability from this claim cannot currently be reasonably estimated, and no provision has been accrued in the Company's financial statements.

In February 2000, the Department of Interior notified the Company and several other producers that certain Native American leases located in the San Juan Basin have expired due to the failure of the leases to produce in paying quantities from February through August 1990. The Department of Interior has demanded abandonment of the property as well as payment of the gross proceeds from the wells minus royalties paid from the date of the alleged cessation of production to present. The Company has filed a Notice of Appeal with the Interior Board of Indian Appeals. Management believes it has strong defenses against this claim and intends to vigorously defend the action. Management's estimate of the potential liability from this claim has been accrued in the Company's financial statements.

In June 2001, the Company was served with a lawsuit styled *Quinque Operating Co., et al. v. Gas Pipelines, et al.* The action was filed in the District Court of Stevens County, Kansas, against the Company and one of its subsidiaries, along with over 200 natural gas transmission companies, producers, gatherers and processors of natural gas. 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. No class has been certified. The allegations in the case are similar to those in the *Grynberg* case; however, the *Quinque* 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. 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

Notes to Consolidated Financial Statements

September 2001, the Company filed a motion to dismiss the lawsuit, which is currently pending. In February 2002, the Company and one of its subsidiaries were dismissed from the suit and another subsidiary of the Company was added. The Company believes that the allegations of this lawsuit are without merit and intends to vigorously defend the action. Any potential liability from this claim cannot currently be reasonably estimated, and no provision has been accrued in the Company's financial statements.

The Company is involved in various other lawsuits and certain governmental proceedings arising in the ordinary course of business. Company 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 the Company's 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, the Company's 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.

6. Financial Instruments

The Company uses financial and commodity-based derivative contracts to manage exposures to commodity price and interest rate fluctuations. The Company does not hold or issue derivative financial instruments for speculative or trading purposes.

Change in Accounting Principle

On January 1, 2001, the Company adopted SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended by SFAS Nos. 137 and 138, by recording a one-time after-tax charge of $44,589,000 in the income statement for the cumulative effect of a change in accounting principle and an unrealized loss of $67,323,000 in accumulated other comprehensive income. The unrealized loss is related to the derivative fair value of cash flow hedges. The charge to the income statement is primarily related to the Company's physical delivery contract with crude oil-based pricing, also referred to as the Enron Btu swap contract.

After adoption of SFAS No. 133, all derivative financial instruments are recorded on the balance sheet at fair value. Change in the fair value of derivatives that are not designated as hedges, as well as the ineffective portion of hedge derivatives, are recorded in derivative fair value gain (loss) in the income statement. Changes in the fair value of effective cash flow hedges are recorded as a component of accumulated other comprehensive income, which is later transferred to earnings when the hedged transaction occurs.

Enron Btu Swap Contract

In 1995, the Company entered a contract to sell gas based on crude oil pricing, also referred to as the Enron Btu swap contract (Note 8). This contract was terminated as a result of the Enron bankruptcy (Note 7). Because the contract pricing is not clearly and closely associated with natural gas prices, it must be considered a non-hedge derivative financial instrument under SFAS No. 133 beginning January 1, 2001, with changes in fair value recorded as a derivative gain (loss) in the income statement.

Prior to termination of the Enron Btu swap contract, the Company entered derivative contracts with another counterparty 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. Changes in fair value of these contracts are recorded as a derivative gain (loss) in the income statement. In March 2002, the Company terminated some of these contracts with maturities of May through December 2002 and received $6.6 million from the counterparty. Because these contracts are non-hedge derivatives, most of the related $6.6 million gain related to their termination was recorded in 2001 derivative fair value gain.

Commodity Price Hedging Instruments

The Company periodically enters into futures contracts, energy swaps, collars and basis swaps to hedge its exposure to price fluctuations on crude oil and natural gas sales. When actual commodity prices exceed the fixed price provided by these contracts, the Company pays this excess to the counterparty, and when actual commodity prices are below the contractually provided fixed price, the Company receives this difference from the counterparty. The Company has hedged its exposure to variability in future cash flows from natural gas sales for transactions occurring through December 2002. See Note 8.

In 2001, net losses on futures and basis swap hedge contracts reduced gas revenue by $11.1 million. Including the effect of fixed price physical delivery contracts, all hedging activities increased gas revenue by $97 million. During 2000, net losses on futures and basis swap hedge contracts reduced gas revenue by $40.5 million and oil revenue by $7.8 million. During 1999, net losses on futures and basis swap hedge contracts reduced gas revenue by $5.7 million and oil revenue by $2.2 million. The effect of fixed price physical delivery contracts was not significant in 2000 or 1999. As of December 31, 2001, an unrealized pre-tax derivative fair value gain of $108.7 million, related to cash flow hedges of gas price risk, was recorded in accumulated other comprehensive income. The ultimate settlement value of these hedges will be recognized in the income statement as gas revenue when the hedged gas sales occur over the next year.

The Company occasionally sells gas call options. Because these options are covered by Company production, they have the same effect on the Company as product hedges when the strike prices are below current market gas prices. However, because written 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 the call options, has been recognized as a loss in derivative fair value, rather than deferring the loss and recognizing it as reduced gas revenue when the hedged production occurs.

Interest Rate Swap Agreements

To reduce the interest rate on a portion of its subordinated debt, the Company entered an agreement with a bank to purchase a portion of the Company's subordinated notes with a face value of $21.6 million. The Company pays the bank a variable interest rate based on three-month LIBOR rates, and receives semiannually from the bank the fixed interest rate on the notes. The term of the agreement for approximately half the notes is through April 2002, and for the remaining half is through November 2002. Any depreciation in market value of the notes from the date purchased by the bank is immediately payable to the bank. Any appreciation in the market value, including any depreciation payments, is receivable from the bank to the extent of the market value of the notes at the end of the agreement. The Company has the option of terminating this agreement and purchasing the notes from the bank at any time at market value. The Company has notified the bank that it will purchase subordinated notes with a face value of $9,725,000 on April 1, 2002, the termination date of the related interest swap agreement. See Note 3. This agreement is recorded in the financial statements as a non-hedge derivative with changes in fair value recorded in the income statement.

In September 1998, to reduce variable interest rate exposure on debt, the Company entered into a series of interest rate swap agreements, effectively fixing its interest rate at an average of 6.9% on a total notional balance of $150 million until September 2005. In 1999 and 2000, the Company terminated these interest rate swaps, resulting in a gain of $2 million. This gain has been deferred and is being amortized against interest expense through September 2005.

Derivative Fair Value (Gain) Loss

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

(in thousands)	2001	2000
Change in fair value of the Enron Btu swap contract	$(27,505)	$ —
Change in fair value of call options and other derivatives that do not qualify for hedge accounting	(27,022)	55,821
Ineffective portion of derivatives qualifying for hedge accounting	157	—
Derivative fair value (gain) loss	$(54,370)	$55,821

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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, 2001 and 2000. The following are estimated fair values and carrying values of the Company's other financial instruments at each of these dates:

	Asset (Liability)			
	December 31, 2001		December 31, 2000	
(in thousands)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Derivative Assets:				
Fixed-price natural gas futures and swaps	$ 116,829	$ 116,829	$ —	$ 3,868
Interest rate swap	2,791	2,791	473	2,651
Other *(a)(b)*	6,080	6,080	—	—
Derivative Liabilities:				
Fixed-price natural gas futures and swaps	(19,198)	(19,198)	—	(112,807)
Natural gas written call options	—	—	(44,189)	(44,189)
Enron Btu swap contract *(c)*	—	—	—	(70,777)
Other *(a)*	(10,157)	(10,157)	—	—
Net derivative asset (liability)	$ 96,345	$ 96,345	$ (43,716)	$(221,254)
Long-term debt	$(856,000)	$(870,720)	$(769,000)	$(774,000)

(a) These contracts were entered prior to termination of the Enron Btu swap contract and 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.

(b) In March 2002, the Company terminated contracts with maturities of May through December 2002 and received $6.6 million from the counterparty. Because these contracts are non-hedge derivatives, most of the related $6.6 million gain related to their termination was recorded in 2001 derivative fair value gain.

(c) The Enron Btu swap contract was terminated in December 2001 (Note 7). The value of this contract immediately prior to termination was a $43.3 million liability, which is recorded as a current liability until legal extinguishment is finalized.

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

Changes in fair value of derivative assets and liabilities are the result of changes in oil and gas prices and interest rates. Natural gas 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 until the hedged transaction occurs.

During 2001, the Company entered 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, the contracts are not required to be recorded in the financial statements. The value of outstanding physical delivery contracts at December 31, 2001 was $36.4 million.

Concentrations of Credit Risk

Although the Company's cash equivalents and derivative financial instruments are exposed to the risk of credit loss, the Company does not believe such risk to be significant. Cash equivalents are high-grade, short-term securities, placed with highly rated financial institutions. Most of the Company's receivables are from a broad and diverse group of energy companies and, accordingly, do not represent a significant credit risk. The Company's gas marketing activities generate receivables from customers including pipeline companies, local distribution companies and end-users in various industries. Financial and commodity-based swap contracts expose the Company to the credit risk of non-performance by the counterparty to the contracts. In general, the Company does not believe this risk is significant since the exposure is diversified among major banks and financial institutions with high credit ratings. See Note 7 regarding credit risk related to the Enron Corporation bankruptcy. Letters of credit or other appropriate security are obtained as considered necessary to limit risk of loss. The Company recorded an allowance for collectibility of all accounts receivable of $4,098,000 at December 31, 2001 and $3,121,000 at December 31, 2000. The Company's bad debt provision was $978,000 in 2001, $1,093,000 in 2000 and $1,347,000 in 1999.

7. Enron Corporation Bankruptcy

As of December 2, 2001, the date of its bankruptcy filing, Enron Corporation was the counterparty to some of the Company's hedge derivative contracts, as well as a purchaser of natural gas under certain physical delivery contracts. One of these contracts was a natural gas physical delivery contract with crude oil-based pricing ("Enron Btu swap contract").

The Company sent Enron notices of contract terminations in November and December 2001. Based on the fair value as of the contract termination dates, Enron owes the Company $7.8 million for physical gas deliveries in November and December 2001, and $13.5 million for net gains on hedge derivative contracts. Enron also owes the Company $14.1 million in net unrealized gains related to undelivered gas under physical delivery contracts. This amount, however, will not be recorded in the financial statements until collectibility is assured.

Also recorded in the balance sheet at December 31, 2001 is a current liability of $43.3 million related to the Enron Btu swap contract, based on fair values at the date of contract termination. As specified under the contract termination provisions, the Company, as the nondefaulting party, has notified Enron that its liability under this contract has been reduced to zero. Based upon discussion with outside legal counsel, the Company believes that these termination provisions are legally enforceable, and accordingly, it has no liability under this contract. However, under generally accepted accounting principles, this liability cannot be credited to income until legal extinguishment of the debt is finalized.

In the event the termination provisions of the Enron Btu swap contract are ultimately not enforced, the Company believes that, based on contract provisions and discussions with outside legal counsel, it should have the right to offset all amounts due from Enron against any Enron Btu swap contract liability, including amounts related to undelivered gas under physical delivery contracts. Because the recorded Enron Btu swap contract liability exceeds total Enron receivables at December 31, 2001, no reserve for asset collectibility has been recorded.

Final resolution of the Enron bankruptcy and related proceedings may result in a settlement materially different from amounts recorded at December 31, 2001. The following is a summary of recorded, unrecorded and total amounts related to Enron:

	Receivable (Payable) at December 31, 2001		
(in thousands)	Recorded	Unrecorded	Total
Accounts receivable:			
Physical delivery contracts	$ 7,817	$14,069	$21,886
Hedge derivative contract fair value	13,534	—	13,534
Total accounts receivable	21,351	14,069	35,420
Current liability — Enron Btu swap contract fair value	(43,272)	—	(43,272)
Net asset (liability)	$(21,921)	$14,069	$(7,852)

8. Natural Gas Sales Commitments

The Company has 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 6 regarding accounting for commodity hedges. All contracts with Enron have been terminated and excluded (Note 7).

	Futures Contracts and Swap Agreements	
2002 Production Period	Mcf per Day	NYMEX Price per Mcf *(a)*
April to May	355,000	$3.66
June	305,000	3.71
July to December	280,000	3.73

(a) Includes approximately $0.05 per Mcf gain that will be deferred and recognized in 2003 related to contract terminations and hedge redesignations.

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(continued)

The Company has entered into basis swap agreements which effectively fix basis for the following production and periods:

Location	2002 Production Period	Mcf per Day	Basis per Mcf *(a)*
Arkoma	April to October	85,000	$ 0.10
East Texas	April to June	170,000	0.00
	July to September	170,000	0.01
	October	150,000	0.00
	November to December	60,000	0.00
Mid-Continent	April to October	20,000	0.12

(a) Reductions from NYMEX gas price for location, quality and other adjustments.

The Company's settlement of futures contracts and basis swap agreements related to first quarter 2002 gas production resulted in increased gas revenue of $32.3 million. This gain will be recognized as an increase in gas revenue of approximately $0.75 per Mcf in the first quarter of 2002. Included in these settlements is $4.4 million related to terminated Enron futures contracts and swap agreements which will be recognized as an increase in gas revenue of approximately $0.10 per Mcf.

In December 2001 and March 2002, the Company closed futures contracts and swap agreements that were designated as cash flow hedges and, accordingly, has recorded deferred gains of $10.5 million in accumulated other comprehensive income. Included in these deferred gains is $7.6 million related to terminated Enron futures contracts. Deferred gains on these closed contracts will be recorded as gas revenue based on production in the following periods:

2002 Production Period	Mcf per Day	Gain per Mcf
April	50,000	$0.72
May	50,000	0.68
June	75,000	0.65
July	75,000	0.62
August	75,000	0.60
September	75,000	0.61
October	75,000	0.49
November	65,000	0.45
December	65,000	0.34

In March 2002, the Company entered into collar agreements which provide a floor (put) and ceiling (call) price for natural gas. If the market price of natural gas exceeds the call price or falls below the put price, the Company receives the fixed price and pays the market price. If the market price of natural gas is between the floor and ceiling price, no payments are due from either the Company or the counterparty. Prices to be realized may be less than these floor and ceiling prices because of location, quality and other adjustments. The Company has entered into collar agreements for the following production periods:

		Average NYMEX Price *(a)*	
2002 Production Period	Mcf per Day	Floor	Ceiling
April to May	75,000	$2.60	$3.20
June	150,000	2.90	3.46
July to September	150,000	2.95	3.52
October to December	165,000	3.27	3.89

(a) Includes reduction of $0.10 per Mcf for cost of collars.

The Company has entered gas physical delivery contracts that are considered to be normal sales, and therefore, are not recorded in the financial statements, because they are not expected to be net cash settled. All Enron contracts have been terminated and excluded. These contracts effectively fix prices for the following production and periods:

Location	2002 Production Period	Mcf per Day	Fixed Price per Mcf
Arkoma	January to March	60,000	$ 4.75
	April to December	20,000	3.61
East Texas	January	50,000	5.06
	February to March	20,000	4.54
	April to December	10,000	3.63
Mid-Continent	January to March	20,000	5.58

Other Physical Delivery Contracts

From August 1995 through July 1998 the Company received an additional $0.30 to $0.35 per Mcf on 10,000 Mcf of gas per day. In exchange therefor, the Company 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 6 regarding accounting for this contract, also referred to as the Enron Btu swap contract, which has been terminated as a result of the Enron bankruptcy (Note 7). Also see Note 6 regarding a related derivative commitment with another counterparty.

As partial consideration for an acquisition, the Company agreed to sell gas volumes ranging from 40,000 Mcf in 2000 to 35,000 Mcf in 2003 at specified discounts from index prices. This commitment was recorded at its total value of $7.5 million in March 1999 in other current and long-term liabilities. The discounts are charged to the liability as taken. As of December 31, 2001, $1,552,000 is recorded in other current liabilities and $455,000 is recorded in other long-term liabilities related to this commitment.

As part of an acquisition, the Company assumed a commitment to sell 6,800 Mcf of gas per day in Arkansas through April 2003 at prices which are adjusted by the monthly index price. In 2001, the prices ranged from $0.44 to $1.44 per Mcf. This contract is considered a normal sale and therefore, is not recorded as a derivative in the Company's financial statements.

In 1998, the Company 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, the Company committed to deliver to EEX a total of approximately 34.3 Bcf (27.8 Bcf net to the Company's interest) of gas during the 10-year period beginning January 1, 2002, with scheduled deliveries by year, subject to certain variables. EEX will reimburse the Company for all royalty and production and property tax payments related to such deliveries. EEX will also pay the Company an operating fee of $0.257 per Mcf for deliveries in 2002, which fee will be escalated annually at a rate of 5.5%. Each December, beginning in 1998, the Company had the option to repurchase a portion of this production payment, based on a total cost of $30 million plus interest accrued from May 1, 1998 through the repurchase date. The Company repurchased portions of the production payment in 2001 and 2002 for $20.7 million (Note 13). According to the terms of the delivery agreement, the Company has the right to receive the repurchased production payment volumes first out of production commencing January 1, 2002. Because the Company has repurchased 18.3 Bcf (14.8 Bcf net) of gas, it should be approximately September 2006 before EEX will begin receiving the remaining 16.0 Bcf (13.0 Bcf net) of gas.

9. Equity

Three-for-Two Stock Splits

The Company effected three-for-two common stock splits on September 18, 2000 and June 5, 2001. 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 the Company's common stock activity:

Shares Issued

(in thousands)	2001	2000	1999
Balance, January 1	123,880	130,924	121,608
Issuance/sale of common stock	—	—	9,000
Issuance/vesting of performance shares	666	1,220	292
Stock option exercises	2,154	4,792	24
Cancellation of shares	—	(13,299)	—
Preferred stock converted to common	5,289	243	—
Balance, December 31	131,989	123,880	130,924

Shares in Treasury

(in thousands)	2001	2000	1999
Balance, January 1	7,547	20,924	20,972
Issuance/sale of common stock	—	(9,900)	(4,500)
Issuance/vesting of performance shares	217	571	—
Stock option exercises	23	414	115
Treasury stock purchases	429	8,837	4,337
Cancellation of shares	—	(13,299)	—
Balance, December 31	8,216	7,547	20,924

In July 1999, the Company issued 9 million shares of common stock at its fair value of $5.08 per share in exchange for its 50% interest in an acquisition and for cash proceeds of $3.2 million which were used to reduce bank debt.

Also in July 1999, the Company sold from treasury 4.5 million shares of common stock in an underwritten public offering for net proceeds of approximately $26.5 million. The proceeds were used to repurchase 4.3 million shares of common stock issued in conjunction with an acquisition.

In May 2000, 13.3 million shares were canceled from treasury stock. This transaction caused a $71.5 million reduction in treasury stock with an offsetting reduction in additional paid-in capital, resulting in no change to total stockholders' equity.

In November 2000, the Company sold from treasury 9.9 million shares of common stock in an underwritten public offering for net proceeds of approximately $126.1 million. The proceeds were used to reduce bank debt.

Treasury Stock

The Company's open market treasury share acquisitions totaled 7.9 million shares in 2000 at an average price of $5.25 and 11,000 shares in 1999 at an average price of $4.69 per share. As of March 27, 2002, 6.5 million shares remain under the May 2000 Board of Directors' authorization to repurchase 6.8 million shares of the Company's common stock.

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, a dividend of one preferred share purchase right was declared for each outstanding share of common stock, par value $.01 per share, payable on September 15, 1998 to stockholders of record on that date. 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 ten years.

Shelf Registration Statement

In October 2001, the Company 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 securities, preferred stock or common stock. The total price of securities to be offered is $600 million, at prices and on terms to be determined at the time of sale. Net proceeds from the sale of such securities are to be used for general corporate purposes, including reduction of bank debt. As of March 2002, no securities have been issued under the shelf registration statement.

Common Stock Warrants

As partial consideration for producing properties acquired in December 1997, the Company issued warrants to purchase 2.1 million shares of common stock at a price of $6.70 per share for a period of five years. These warrants were valued at $5.7 million and recorded as additional paid-in capital.

Common Stock Dividends

The Board of Directors declared quarterly dividends of $0.0045 per common share from 1999 through second quarter 2000, $0.0067 per common share for third quarter 2000 through first quarter 2001 and $0.01 per common share for the remainder of 2001. See Note 3 regarding restrictions on dividends.

Series A Convertible Preferred Stock

Series A convertible preferred stock is recorded in the accompanying December 31, 2000 consolidated balance sheet at its liquidation preference of $25 per share. During 2000, 50,000 shares of convertible preferred stock were converted into 243,000 shares of common stock. In January 2001, the Company sent notice to preferred stockholders that it would redeem all outstanding shares in February 2001 at a price of $25.94 per share plus accrued and unpaid dividends. Prior to the redemption date, 1.1 million outstanding shares of preferred stock were converted into 5.3 million common shares.

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
2001			
Basic			
Net income	$248,816		
Earnings available to common stock – basic	248,816	122,505	$2.03
Diluted			
Effect of dilutive securities:			
Stock options	—	484	
Preferred stock	—	377	
Warrants	—	1,260	
Earnings available to common stock – diluted	$248,816	124,626	$2.00
2000			
Basic			
Net income	$116,993		
Preferred stock dividends	(1,758)		
Earnings available to common stock – basic	115,235	106,730	$1.08
Diluted			
Effect of dilutive securities:			
Stock options	—	777	
Preferred stock	1,758	5,470	
Warrants	—	581	
Earnings available to common stock – diluted	$116,993	113,558	$1.03
1999			
Basic			
Net income	$ 46,743		
Preferred stock dividends	(1,779)		
Earnings available to common stock – basic	44,964	105,341	$0.43
Diluted			
Effect of dilutive securities:			
Stock options	—	243	
Preferred stock	1,779	5,534	
Warrants	—	—	
Earnings available to common stock – diluted	$ 46,743	111,118	$0.42

11. Supplemental Cash Flow Information

The consolidated statements of cash flows exclude the following non-cash transactions (Notes 9 and 12):

- Conversion of 1.1 million shares of preferred stock to 5.3 million shares of common stock in 2001 and conversion of 50,000 shares of preferred stock to 243,000 shares of common stock in 2000
- Cancellation of 13.3 million shares of treasury stock in 2000
- Sale of Hugoton Royalty Trust units in 2000 in exchange for 743,000 shares of common stock valued at $11.3 million, and

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in 1999 in exchange for 111,000 shares of common stock valued at $700,000

- Purchase of a 50% interest in an acquisition in 1999 in exchange for 8.4 million shares of common stock, valued at $42.5 million
- Performance shares activity, including:
  - Grants of 878,000 shares in 2001, 1,230,000 shares in 2000 and 319,000 shares in 1999 to key employees and nonemployee directors
  - Vesting of 602,000 shares in 2001, 1,510,000 shares in 2000 and 27,000 shares in 1999
  - Forfeiture of 9,000 shares in 2001 and 27,000 shares in 1999
- Receipt of common stock of 66,000 shares (valued at $967,000) in 2000 for the option price of exercised stock options

Interest payments in 2001 totaled $59,550,000 (including $6,649,000 of capitalized interest), $80,067,000 in 2000 (including $3,488,000 of capitalized interest) and $70,500,000 in 1999 (including $1,353,000 of capitalized interest). Net income tax refunds were $140,000 during 2001 and $322,000 during 1999; income tax payments were $1,085,000 in 2000.

12. Employee Benefit Plans

401(k) Plan

The Company sponsors a 401(k) benefit plan that allows employees to contribute and defer a portion of their wages. The Company matches employee contributions of up to 10% of wages. Employee contributions vest immediately while the Company's 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 $3,884,000 in 2001, $3,226,000 in 2000 and $2,514,000 in 1999.

Post-Retirement Health Plan

Effective January 1, 2001, the Company adopted a retiree medical plan for employees who retire at age 55 or over with a minimum of five years full-time service. Benefits under the plan are the same as for active employees, and continue until the retired employee or the employee's dependents are eligible for Medicare or another similar federal health insurance program. All participants pay premiums as determined by the Company. Post-retirement medical benefits are not pre-funded by the Company, but are paid when incurred. The status of the Company's post-retirement health plan for 2001 is as follows:

(in thousands)	2001
Change in benefit obligation:	
Benefit obligation at January 1	$ 804
Service cost	221
Interest cost	62
Actuarial loss	1
Benefit payments	(10)
Benefit obligation at December 31	$ 1,078
Amounts recognized in the consolidated balance sheet:	
Funded status	$(1,078)
Unrecognized net actuarial gain	(9)
Accrued benefit liability, as recognized in the consolidated balance sheet at December 31, 2001	$(1,087)
Components of net periodic benefit cost:	
Service cost	$ 221
Interest cost	62
Recognized prior service cost	804
Net periodic benefit cost	$ 1,087

The weighted average discount rate used by the Company in determining the accumulated post-retirement benefit obligation was 7.5%. For measurement purposes, the annual rate of increase in the covered health care benefits was assumed to range from 9% in 2001 to 6% in 2006 and beyond. A 1% change in the assumed health care cost trend rate would have approximately a $158,000 effect on total estimated service and interest cost and approximately a $417,000 effect on the post-retirement benefit obligation.

1994 and 1997 Stock Incentive Plans

Under the 1994 Stock Incentive Plan and the 1997 Stock Incentive Plan, a total of 5,063,000 shares of common stock may be issued under each plan to directors, officers and other key employees pursuant to grants of stock options or performance shares. At December 31, 2001, there are 1,341,000 shares available for grant under the 1994 Plan and 1,181,000 shares available for grant under the 1997 Plan. Options vest and become exercisable on terms specified when granted by the compensation committee ("the Committee") of the Board of Directors. Options granted under the 1994 Plan have a term of ten years and are not exercisable until six months after their grant date. Options granted under the 1997 Plan have a term of ten years. Options granted under the 1994 Plan and the 1997 Plan generally vest in equal amounts over five years, with provisions for earlier vesting if specified performance requirements are met. All outstanding options under the 1994 Plan were vested by resolution of the Board of Directors.

1998 Stock Incentive Plan

Under the 1998 Stock Incentive Plan, a total of 13,500,000 shares of common stock may be issued pursuant to grants of stock options or performance shares. Grants under the 1998 Plan are subject to the provision that outstanding stock options and performance shares under all the Company's stock incentive plans cannot exceed 6% of the Company's outstanding common stock at the time such grants are made. At December 31, 2001, there were 1,249,000 shares available for grant under the 1998 Plan. Stock options generally vest and become exercisable annually in equal amounts over a five-year period, with provision for accelerated vesting when the common stock price reaches specified levels. There were 44,000 options outstanding at December 31, 2001 that vest when the common stock price reaches $23.33, 174,000 options that vest when the common stock price reaches $21.50, 5,000 options that vest when the common stock price reaches $20.00 and 174,000 options that vest when the common stock price reaches $19.50. The options with the common stock target prices of $19.50 and $20.00 vested in March 2002.

Performance Shares

Performance shares granted under the 1994, 1997 and 1998 Plans are subject to restrictions determined by the Committee and are subject to forfeiture if performance targets are not met. Otherwise, holders of performance shares generally have all the voting, dividend and other rights of other common stockholders. The Company issued performance shares to key employees totaling 871,000 in 2001, 1,230,000 in 2000 and 292,000 in 1999. Performance shares vested, totaling 595,000 in 2001 and 1,510,000 in 2000, when the common stock price reached specified levels. In 2001, 9,000 of the performance shares issued in 2001 were forfeited, and in 1999, 27,000 performance shares issued in 1998 were forfeited. General and administrative expense includes compensation related to performance shares of $8.7 million in 2001, $18.4 million in 2000 and $102,000 in 1999. As of December 31, 2001, there were 159,000 performance shares that vest when the common stock price reaches $18.30, 242,000 performance shares that vest when the common stock price reaches $21.67 and 13,500 performance shares that vest in increments of 6,750 in each of 2002 and 2003. In February 2002, upon vesting of the performance shares with the $18.30 common stock vesting price, an additional 159,000 performance shares were issued that vested when the stock price reached $20.00 in March 2002. The Company also issued to nonemployee directors a total of 8,000 performance shares in February 2002, 7,000 performance shares in 2001 and 27,000 performance shares in 1999, all of which vested upon grant.

In 2001, the Board approved an agreement with certain executive officers under which the officers, immediately prior to a change in control of the Company, will receive a total grant of 150,000 performance shares for every $1.67 increment in the closing price of the Company's common stock above $20.00. Unless otherwise designated by the Board, the number of performance shares granted under the agreement will be reduced by the number of performance shares awarded to the officers between the date of the agreement and the date of the change in control. Certain officers will

Notes to Consolidated Financial Statements

(continued)

also receive a total grant of 232,500 performance shares immediately prior to a change in control without regard to the price of the Company's common stock.

Royalty Trust Option Plans

Under the 1998 Royalty Trust Option Plan, the Company granted certain officers options to purchase 1,290,000 Hugoton Royalty Trust units at prices of $8.03 and $9.50 per unit, or a total of $12 million. These options were exercised in 2000 and 1999, resulting in non-cash compensation expense of $7.1 million in 2000 and $60,000 in 1999.

Option Activity and Balances

The following summarizes option activity and balances from 1999 through 2001:

	Weighted Average Exercise Price	Stock Options
1999		
Beginning of year	$ 6.33	5,937,719
Grants	4.74	922,218
Exercises	3.05	(23,540)
Forfeitures	5.17	(64,293)
End of year	6.13	6,772,104
Exercisable at end of year	4.93	3,014,042
2000		
Beginning of year	$ 6.13	6,772,104
Grants	13.33	7,143,752
Exercises	6.54	(6,965,106)
Forfeitures	5.94	(369,528)
End of year	13.43	6,581,222
Exercisable at end of year	12.83	4,722,764
2001		
Beginning of year	$ 13.43	6,581,222
Grants	18.74	5,713,621
Exercises	13.19	(5,325,655)
Forfeitures	18.81	(81,000)
End of year	17.93	6,888,188
Exercisable at end of year	18.03	6,492,188

The following summarizes information about outstanding options at December 31, 2001:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number	Weighted Average Remaining Term	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
$ 1.84 - $ 5.52	24,049	5.5 years	$ 4.29	24,049	$ 4.29
$ 5.53 - $ 9.20	37,965	6.9 years	7.49	37,965	7.49
$ 9.21 - $12.88	46,946	8.6 years	10.35	46,946	10.35
$12.89 - $18.39	2,835,741	9.1 years	15.96	2,483,379	15.98
$18.40 - $20.35	3,943,487	9.3 years	19.62	3,899,849	19.62
	6,888,188			6,492,188	

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 $8.68 in 2001, $6.85 in 2000 and $2.85 in 1999.

	2001	2000	1999
Risk-free interest rates	4.9%	5.8%	5.8%
Dividend yield	0.2%	0.2%	3.0%
Weighted average expected lives	4 years	5 years	5 years
Volatility	54%	53%	91%

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 2001, 2000 and 1999, 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)		2001	2000	1999
Earnings available to common stock:				
As reported		$ 248,816	$115,235	$44,964
Pro forma		$ 204,543	$ 91,194	$40,373
Earnings per common share:				
Basic	As reported	$ 2.03	$ 1.08	$ 0.43
	Pro forma	$ 1.67	$ 0.85	$ 0.38
Diluted	As reported	$ 2.00	$ 1.03	$ 0.42
	Pro forma	$ 1.64	$ 0.82	$ 0.38

13. Acquisitions and Dispositions

Acquisitions

In January 2001, the Company acquired gas properties in East Texas and Louisiana for $115 million from Herd Producing Company, Inc., and in February 2001, it acquired gas properties in East Texas for $45 million from Miller Energy, Inc. and other owners. In August 2001, the Company acquired primarily underdeveloped acreage in the Freestone area of East Texas for approximately $22 million. The purchases were funded with bank debt and are subject to typical post-closing adjustments.

Acquisitions have been recorded using the purchase method of accounting. The following presents unaudited pro forma results of operations for the year ended December 31, 2000 as if these acquisitions had been consummated immediately prior to January 1, 2000. Pro forma results are not presented for the year ended December 31, 2001 because the effects of these acquisitions excluded from 2001 results are not significant. These pro forma results are not necessarily indicative of future results.

(in thousands, except per share data)	Pro Forma 2000 (Unaudited)
Revenues	$620,113
Net income	$115,231
Earnings available to common stock	$113,473
Earnings per common share:	
Basic	$ 1.06
Diluted	$ 1.01
Weighted average shares outstanding	106,730

In January 2001, the Company repurchased 9.1 Bcf of natural gas for $9.9 million from a production payment sold to EEX Corporation in a 1998 acquisition. In January 2002, the Company repurchased an additional 9.2 Bcf of natural gas for $10.8 million. See Note 8.

In 1999, the Company and Lehman Brothers acquired the common stock of Spring Holding Company, a private oil and gas company, for a combination of cash and the Company's common stock totaling $85 million. The Company and Lehman each owned 50% of a limited liability company that acquired the common stock of Spring. In September 1999, the Company acquired Lehman's 50% interest in Spring for $44.3 million. This acquisition included oil and gas properties located in the Arkoma Basin of Arkansas and Oklahoma with a purchase price of $235 million. After purchase accounting adjustments and other costs, the cost of the properties was $257 million.

The Company also acquired in 1999, with Lehman as 50% owner, Arkoma Basin properties from affiliates of Ocean Energy, Inc. for $231 million. The Company acquired Lehman's interest in the Ocean Energy Acquisition in March 2000 for $111 million.

Dispositions

In June 2001, the Company and Cross Timbers Royalty Trust filed an amended registration statement with the Securities and Exchange Commission to sell 1,360,000 units (22.7% of outstanding units) owned by the Company. The Company's sale of these units is dependent upon commodity prices and related market conditions for oil and gas equities. These units are classified as producing properties in the accompanying balance sheet at a net cost of $12.2 million at December 31, 2001.

In March 2000, the Company sold producing properties in Crockett County, Texas, and Lea County, New Mexico for total gross proceeds of

Notes to Consolidated Financial Statements

$68.3 million. In May and June 1999, the Company sold primarily nonoperated gas-producing properties in New Mexico for $44.9 million. In September 1999, the Company sold primarily nonoperated oil- and gas-producing properties in Oklahoma, Texas, New Mexico and Wyoming for $63.5 million, including sales of $22.5 million of properties acquired in the Spring Holding Company acquisition.

In December 1998, the Company formed the Hugoton Royalty Trust by conveying 80% net profits interests in properties located 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. In April and May 1999, the Company sold 17 million, or 42.5%, of the trust units in an initial public offering at a price of $9.50 per unit, less underwriters' discount and expenses. Total net proceeds from the sale were $148.6 million, resulting in a gain of $40.3 million before income tax. Proceeds from the sale were used to reduce bank debt. In 1999 and 2000, officers exercised options to purchase a total of 1.3 million Hugoton Royalty Trust units from the Company pursuant to the 1998 Royalty Trust Option Plan in exchange for shares of Company common stock. The Company recognized gains of $11 million in 2000 and $235,000 in 1999 on these sales of trust units.

14. Quarterly Financial Data (Unaudited)

The following are summarized quarterly financial data for the years ended December 31, 2001 and 2000:

(in thousands, except per share data)	Quarter 1st	2nd	3rd	4th
2001				
Revenues	$249,152	$209,021	$197,307	$183,268
Gross profit *(a)*	$164,788	$167,514	$129,604	$ 88,269
Earnings available to common stock	$ 46,748	$ 90,533	$ 70,342	$ 41,193
Earnings per common share:				
Basic	$ 0.39	$ 0.74	$ 0.57	$ 0.33
Diluted	$ 0.38	$ 0.73	$ 0.56	$ 0.33
Average shares outstanding	119,640	123,050	123,596	123,669
2000				
Revenues	$113,326	$121,650	$160,519	$205,356
Gross profit *(a)*	$ 44,997	$ 30,094	$ 80,981	$105,490
Earnings available to common stock	$ 33,267	$ 798	$ 31,366	$ 49,804
Earnings per common share:				
Basic	$ 0.31	$ 0.01	$ 0.30	$ 0.45
Diluted	$ 0.29	$ 0.01	$ 0.28	$ 0.42
Average shares outstanding	108,662	103,376	104,277	110,592

(a) Operating income before general and administrative expense.

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

All of the Company's 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)	2001	2000	1999
Acquisitions:			
Producing properties	$238,041	$ 31,983	$505,912
Undeveloped properties	3,980	3,490	4,182
Development *(a)*	385,479	163,224	89,306
Exploration:			
Geological and geophysical studies	2,123	829	872
Dry hole expense	2,189	—	—
Rental expense and other	1,126	218	32
Total	$632,938	$199,744	$600,304

(a) Includes capitalized interest of $6,649,000 in 2001, $3,488,000 in 2000 and $1,353,000 in 1999.

Proved Reserves

The Company's 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.

Standardized Measure

The standardized measure of discounted future net cash flows ("standardized measure") 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. 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.

The standardized measure does not represent management's estimate of the Company's 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 of discounted cash flows, are influenced by seasonal demand and other factors and may not be the most representative in estimating future revenues or reserve data.

Proved Reserves (in thousands)	Oil (Bbls)	Gas (Mcf)	Natural Gas Liquids (Bbls)
December 31, 1998	54,510	1,209,224	17,174
Revisions	10,792	60,011	1,838
Extensions, additions and discoveries	3,003	166,669	3,357
Production	(5,112)	(105,120)	(1,325)
Purchases in place	2,790	494,666	20
Sales in place	(4,380)	(279,827)	(3,162)
December 31, 1999	61,603	1,545,623	17,902
Revisions	2,709	142,974	3,709
Extensions, additions and discoveries	1,145	258,843	1,951
Production	(4,736)	(125,857)	(1,622)
Purchases in place	833	26,557	72
Sales in place	(3,109)	(78,457)	—
December 31, 2000	58,445	1,769,683	22,012
Revisions	(4,201)	(96,990)	(2,193)
Extensions, additions and discoveries	3,317	469,602	2,081
Production	(4,978)	(152,178)	(1,601)
Purchases in place	1,484	248,339	—
Sales in place	(18)	(2,978)	—
December 31, 2001	54,049	2,235,478	20,299

Proved Developed Reserves (in thousands)	Oil (Bbls)	Gas (Mcf)	Natural Gas Liquids (Bbls)
December 31, 1998	42,876	968,495	14,000
December 31, 1999	48,010	1,225,014	13,781
December 31, 2000	46,334	1,328,953	16,448
December 31, 2001	41,231	1,452,222	14,774

Notes to Consolidated Financial Statements

(continued)

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

(in thousands)	December 31 2001	2000	1999
Future cash inflows	$ 6,366,557	$18,866,832	$ 5,113,094
Future costs:			
Production	(1,989,344)	(3,237,574)	(1,549,401)
Development	(620,611)	(389,698)	(294,250)
Future net cash flows before income tax	3,756,602	15,239,560	3,269,443
Future income tax	(879,874)	(4,947,614)	(718,892)
Future net cash flows	2,876,728	10,291,946	2,550,551
10% annual discount	(1,354,679)	(5,029,916)	(1,153,611)
Standardized measure *(a)*	$ 1,522,049	$ 5,262,030	$ 1,396,940

(a) Before income tax, the year-end standardized measure (or discounted present value of future net cash flows) was $1,947,441,000 in 2001, $7,748,632,000 in 2000 and $1,765,936,000 in 1999.

Changes in Standardized Measure of Discounted Future Net Cash Flows

(in thousands)	2001	2000	1999
Standardized measure, January 1	$ 5,262,030	$ 1,396,940	$ 808,403
Revisions:			
Prices and costs	(6,285,062)	5,096,973	608,123
Quantity estimates	173,587	190,457	62,033
Accretion of discount	455,788	123,225	70,256
Future development costs	(408,772)	(196,048)	(113,110)
Income tax	2,278,522	(2,082,745)	(259,403)
Production rates and other	1,090	1,378	(137)
Net revisions	(3,784,847)	3,133,240	367,762
Extensions, additions and discoveries	252,524	1,018,349	125,209
Production	(653,626)	(441,323)	(215,869)
Development costs	312,435	128,757	70,275
Purchases in place *(a)*	148,111	115,866	414,759
Sales in place *(b)*	(14,578)	(89,799)	(173,599)
Net change	(3,739,981)	3,865,090	588,537
Standardized measure, December 31	$ 1,522,049	$ 5,262,030	$ 1,396,940

(a) 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.

(b) 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.

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 realized oil prices used in the estimation of proved reserves and calculation of the standardized measure were $17.39 for 2001, $25.49 for 2000 and $24.17 for 1999. Year-end average realized gas prices were $2.36 for 2001, $9.55 for 2000 and $2.20 for 1999. Year-end average realized natural gas liquids prices were $8.70 for 2001, $26.33 for 2000 and $13.83 for 1999. Proved oil and gas reserves at December 31, 2001 include:

- 1,658,000 Bbls of oil and 204,123,000 Mcf of gas and discounted present value before income tax of $159,275,000 related to the Company's ownership of approximately 54% of Hugoton Royalty Trust units at December 31, 2001.
- 605,000 Bbls of oil and 7,305,000 Mcf of gas and discounted present value before income tax of $9,974,000 related to the Company's ownership of approximately 23% of Cross Timbers Royalty Trust units at December 31, 2001.

The standardized measure does not include the effect of hedge derivatives or fixed price physical delivery contracts. Including the effects of these contracts, the standardized measure before income tax would increase by $151.6 million at December 31, 2001 and $4.3 million at December 31, 1999, and would decrease by $193.8 million at December 31, 2000.

Based on assumed realized prices of $25.00 per Bbl for oil, $3.50 per Mcf for gas and $16.00 per Bbl for natural gas liquids, estimated proved reserves at December 31, 2001 would be 59.3 million Bbls of oil, 2.3 Tcf of natural gas and 22.3 million Bbls of natural gas liquids. Using these prices, the present value of estimated future cash flows, discounted at 10% and before income tax, would be $3.5 billion.

Report of Independent Public Accountants

To the Board of Directors and Stockholders of
XTO Energy Inc.

We have audited the accompanying consolidated balance sheets of XTO Energy Inc. and its subsidiaries as of December 31, 2001 and 2000, and the related consolidated income statements, statements of cash flows and stockholders' equity for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2001 and 2000, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

As discussed in Note 6 to Consolidated Financial Statements, the Company changed its method of accounting for its derivative instruments and hedging activities effective January 1, 2001, in connection with its adoption of Statement of Financial Accounting Standards No. 133, "*Accounting for Derivative Instruments and Hedging Activities*," as amended.

Arthur Andersen LLP

ARTHUR ANDERSEN LLP

Fort Worth, Texas
March 28, 2002

Market Price of Common Stock and Dividends Declared Per Share

XTO Energy common stock began trading on the New York Stock Exchange on May 11, 1993 under the symbol "XTO." The following table shows the high and low prices of XTO Energy common stock and the dividends declared for each quarter of 2000 and 2001. These values have been adjusted for the three-for-two splits that occurred in September 2000 and June 2001. As of March 1, 2002, there were 658 holders of record of XTO Energy common stock.

QUARTER END	High	Low	Dividend
2001			
March 31	$ 20.633	$ 12.542	$ 0.0067
June 30	21.733	13.750	0.0100
September 30	16.500	12.300	0.0100
December 31	19.300	13.250	0.0100
2000			
March 31	$ 5.944	$ 3.361	$ 0.0045
June 30	9.889	5.444	0.0045
September 30	14.417	7.111	0.0067
December 31	19.333	11.167	0.0067

Directors and Officers

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 *(b) (c)*
President
Texas Bank
Fort Worth Downtown

J. Luther King, Jr. *(a)*
President
Luther King Capital
Management Corporation

Jack P. Randall
President
Randall & Dewey

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

Dr. Lane G. Collins *(a) (b) (c)*
Professor of Accounting
Baylor University

Keith A. Hutton
Executive Vice President,
Operations

Vaughn O. Vennerberg II
Executive Vice President,
Administration

(a) Audit Committee

(b) Compensation Committee

(c) Nominating Committee

SENIOR 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

Bennie G. Kniffen
Senior Vice President and
Controller

Timothy L. Petrus
Senior Vice President, Acquisitions

Kenneth F. Staab
Senior Vice President, Engineering

Thomas L. Vaughn
Senior Vice President, Operations

OTHER OFFICERS

Virginia N. Anderson
Corporate Secretary

Adam E. Auten
Assistant Treasurer

Nick J. Dungey
Vice President, Natural Gas
Operations

Robert B. Gathright
Assistant Controller and
Director of Budget and Planning

Ken K. Kirby
Vice President, Operations
East Texas

Gary L. Markestad
Vice President, Operations
San Juan Basin

Frank G. McDonald
Vice President and
General Counsel and Assistant
Secretary

Robert C. Myers
Vice President, Human Resources

John M. O'Rear
Vice President and Treasurer

Edwin S. Ryan, Jr.
Vice President, Land

Terry L. Schultz
Vice President, Gas Marketing

Doug C. Schultze
Vice President, Operations
Permian Basin

Gary D. Simpson
Vice President, Investor Relations

Mark A. Stevens
Vice President, Taxation

E. E. Storm III
Vice President and
General Counsel,
Land and Acquisitions

L. Frank Thomas III
Vice President,
Information Technology

Michael R. Tyson
Assistant Controller and
Director of Financial Reporting

Corporate Information

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810 Houston Street
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Oklahoma City Office
210 West Park Avenue, Suite 2350
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Midland, Texas 79705
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Tyler Office
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Tyler, Texas 75701
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Bldg. K, Suite 1
Farmington, New Mexico 87401
(505) 324-1090

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Ozark, Arkansas 72949
(501) 667-4819

Alaska Office
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Kenai, Alaska 99611
(907) 776-8473

Annual Meeting
Tuesday, May 21, 2002 at 10 a.m.
Fort Worth Club Tower
777 Taylor Street
12th Floor, Horizon Room
Fort Worth, Texas

Independent Auditors
Arthur Andersen LLP
Fort Worth, Texas

Senior Subordinated Notes
9¼% Notes due 2007
8¼% Notes due 2009

Transfer Agents and Registrars
Common Stock:
Mellon Investor Services LLC
Dallas, Texas
www.mellon-investor.com
Senior Subordinated Notes:
Bank of New York
Corporate Trust Division
New York, New York

Form 10-K
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. 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 balance, transfer procedures and year-end tax information call (888) 877-2892.

Web Site
www.xtoenergy.com

XTO Energy Inc.
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www.xtoenergy.com

This Annual Report, other than historical financial information, contains forward-looking statements regarding results of future development expenditures, growth in production, growth in reserves, cash flow per share, proved reserves, debt levels, strategic acquisitions, potential stock prices, availability of natural gas supply and other matters subject to a number of risks and uncertainties which are detailed in the Company's Annual Report on Form 10-K for the year ended December 31, 2001, which is incorporated by this reference as though fully set forth herein. Although the Company believes that the expectations reflected in such forward-looking statements are reasonable based on currently available information, there is no assurance that these goals and projections can or will be met.

XTO ENERGY

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