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

FORM 10-K/A

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

For the fiscal year ended December 31, 2003

OR

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

For the transition period from ______ to ______

Commission File Number 1-3523

Westar Energy, Inc.
(Exact name of registrant as specified in its charter)

Kansas	48-0290150
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)

818 South Kansas Avenue, Topeka, Kansas 66612 (785) 575-6300

(Address, including Zip code and telephone number, including area code, of registrant’s principal executive offices)

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

Common Stock, par value $5.00 per share	New York Stock Exchange
(Title of each class)	(Name of each exchange on which registered)

Securities registered pursuant to section 12(g) of the Act:

Preferred Stock, 4 1/2% Series, $100 par value

(Title of Class)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

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

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). Yes ☒ No ☐

The aggregate market value of the voting common equity held by non-affiliates of the registrant was approximately $1,170,717,860 at June 30, 2003.

Indicate the number of shares outstanding of each of the registrant’s classes of common stock, as of the latest practicable date.

Common Stock, par value $5.00 per share	73,289,873 shares
(Class)	(Outstanding at February 23, 2004)

DOCUMENTS INCORPORATED BY REFERENCE:

None.

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FORWARD-LOOKING STATEMENTS

Certain matters discussed in this Annual Report on Form 10-K are "forward-looking statements." The Private Securities Litigation Reform Act of 1995 has established that these statements qualify for safe harbors from liability. Forward-looking statements may include words like we "believe," "anticipate," "target," "expect," "pro forma," "estimate," "intend" and words of similar meaning. Forward-looking statements describe our future plans, objectives, expectations or goals. Such statements address future events and conditions concerning:

- capital expenditures,
- earnings,
- liquidity and capital resources,
- litigation,
- accounting matters,
- possible corporate restructurings, acquisitions and dispositions,
- the sale of assets and the issuance of equity proposed in our Debt Reduction Plan approved by the Kansas Corporation Commission on July 25, 2003,
- a possible new revolving credit facility,
- compliance with debt and other restrictive covenants,
- interest rates and dividends,
- environmental matters,
- nuclear operations, and
- the overall economy of our service area.

What happens in each case could vary materially from what we expect because of such things as:

- electric utility deregulation or re-regulation,
- regulated and competitive markets,
- ongoing municipal, state and federal activities,
- economic and capital market conditions,
- changes in accounting requirements and other accounting matters,
- changing weather,
- rates, cost recoveries and other regulatory matters,
- the impact of changes and downturns in the energy industry and the market for trading wholesale electricity,
- the impact of changes in "Hours of Service" legislation that was enacted in January 2004 on the number of hours during which employees may operate equipment,
- the impact of the outcome of the notice of violation received on January 22, 2004 from the Environmental Protection Agency and other environmental matters,
- the outcome of the investigation being conducted by the Federal Energy Regulatory Commission regarding power trades with Cleco Corporation and its affiliates and other energy marketing and transmission transactions,
- political, legislative, judicial and regulatory developments,
- the impact of the purported shareholder and employee class action lawsuits filed against us,
- the impact of our potential liability to David C. Wittig and Douglas T. Lake for unpaid compensation and benefits and the impact of claims they have made against us related to the termination of their employment and the publication of the report of the special committee of the board of directors,
- the impact of changes in interest rates,
- changes in, and the discount rate assumptions used for, pension and other post-retirement and post-employment benefit liability calculations, as well as actual and assumed investment returns on pension plan assets,
- the impact of changing interest rates and other assumptions on our decommissioning liability for Wolf Creek,
- transmission reliability rules,
- Kansas Corporation Commission utility service reliability rules,
- changes in the expected tax benefits and contingent payments resulting from the loss on the sale of our monitored services business,
- homeland security considerations,

- coal, natural gas and oil prices, and
- other circumstances affecting anticipated operations, sales and costs.

These lists are not all-inclusive because it is not possible to predict all factors. This report should be read in its entirety. No one section of the report deals with all aspects of the subject matter. Any forward-looking statement speaks only as of the date such statement was made, and we are not obligated to update any forward-looking statement to reflect events or circumstances after the date on which such statement was made except as required by applicable laws or regulations.

PART I

ITEM 1. BUSINESS

GENERAL

Westar Energy, Inc., a Kansas corporation incorporated in 1924, is the largest electric utility in Kansas. Unless the context otherwise indicates, all references in this Annual Report on Form 10-K to "the company," "we," "us," "our" and similar words are to Westar Energy, Inc. and its consolidated subsidiaries. The term "Westar Energy" refers to Westar Energy, Inc. alone and not together with its consolidated subsidiaries. We provide electric generation, transmission and distribution services to approximately 644,000 customers in Kansas. Westar Energy provides these services in northeastern Kansas, including the Topeka, Lawrence, Manhattan, Salina and Hutchinson metropolitan areas. Kansas Gas and Electric Company (KGE), our wholly owned subsidiary, provides these services in south-central and southeastern Kansas, including the Wichita metropolitan area. Both Westar Energy and KGE conduct business using the name Westar Energy. Our corporate headquarters is located at 818 South Kansas Avenue, Topeka, Kansas 66612.

KGE owns a 47% interest in the Wolf Creek Generating Station (Wolf Creek), a nuclear power plant located near Burlington, Kansas, and a 47% interest in Wolf Creek Nuclear Operating Corporation (WCNOC), the operating company for Wolf Creek.

Westar Industries, Inc. (Westar Industries), our wholly owned subsidiary, owned an 87% interest in Protection One, Inc. (Protection One), a publicly traded company that provides monitored security services, and our investment in Protection One Europe. Westar Industries now owns other non-material investments. We sold our interest in Protection One on February 17, 2004, and we sold our interest in Protection One Europe on June 30, 2003. In 2003, we classified our interests in monitored security businesses as discontinued operations. See Note 5 of the Notes to Consolidated Financial Statements, "Discontinued Operations," for additional information about the classification of our monitored security businesses as discontinued operations.

SIGNIFICANT BUSINESS DEVELOPMENTS DURING 2003

KCC Orders and Debt Reduction Plan

On February 6, 2003, we filed a debt reduction plan (the Debt Reduction Plan) with the Kansas Corporation Commission (KCC) in response to the KCC's order that would have required us to reduce debt to $1.67 billion by August 1, 2003. In the Debt Reduction Plan, we outlined our plans for paying down debt and simplifying our business. The Debt Reduction Plan calls for the sale of our non-utility assets, including our interests in Protection One and Protection One Europe and our minority equity interest in ONEOK, Inc. (ONEOK), a diversified energy company. As part of the Debt Reduction Plan, we reduced our quarterly dividend on our common stock 37% to $0.19 per share beginning with the dividend paid April 1, 2003.

On July 21, 2003, we entered into a Stipulation and Agreement (Stipulation) with the KCC staff and other intervenors in the docket considering the Debt Reduction Plan. The KCC issued an order approving the Stipulation on July 25, 2003. The principal terms of the Stipulation are as follows:

- We will fully implement the Debt Reduction Plan by December 31, 2004, unless prevented by events beyond our control, in which case the KCC may extend the deadline for implementation upon a proper showing by us.
- We will reduce our debt to a level consistent with investment grade bond ratings and have a capital structure comprised of at least 40% common equity by December 31, 2004. This commitment replaces the requirement imposed in the previous KCC order that we reduce utility debt to $1.67 billion by August 1, 2003.

- We will file a rate case, which may or may not include a request for a change in rates, by May 1, 2005, based on a test year consisting of the 12 months ending December 31, 2004.
- We will pay to our Kansas jurisdictional customers rebates of $10.5 million on May 1, 2005 and $10.0 million on January 1, 2006.
- We will also pay a rebate to customers for any amounts we may recover from David C. Wittig, our former president, chief executive officer and chairman, and Douglas T. Lake, our former executive vice president, chief strategic officer and member of the board, for compensation totaling approximately $2.3 million paid to them that was included in our electric rates during calendar years 1998 through 2002, net of costs we incur to recover the funds. See Note 19 of the Notes to Consolidated Financial Statements, “Legal Proceedings,” for more information about our efforts to recover compensation from Mr. Wittig and Mr. Lake.
- Westar Industries will transfer to Westar Energy all of its stock in ONEOK and all of its cash in excess of $2.0 million within 30 days of the date of the order.

In August 2003, we began ratably recording a regulatory liability for the rebates that will be paid to customers in 2005 and 2006. Accordingly, as of December 31, 2003, we have recorded a regulatory liability of $3.5 million for revenue to be refunded, which is included in other liabilities on our consolidated balance sheets.

Also in August 2003, Westar Industries transferred to Westar Energy all of its remaining stock in ONEOK and all of its cash in excess of $2.0 million. Westar Industries has continued to transfer cash in excess of $2.0 million in subsequent months. These transfers are intercompany transactions that do not result in any change to the amounts reported on our consolidated financial statements. In addition, in accordance with a KCC order, an intercompany receivable in the amount of $710.5 million from Westar Industries was reclassified as an investment in Westar Industries. This intercompany transaction is eliminated in consolidation.

In 2003, we reduced our debt by $965.7 million primarily through use of the proceeds from the sale of our ONEOK stock and through the retirement of $135.0 million of debt that was economically defeased in 2002. With the closing of the sale of our interest in Protection One on February 17, 2004, we received proceeds of $122.2 million, which will also be used to reduce debt. We plan to issue $100 million to $250 million of equity during 2004.

Sale of ONEOK Stock Investment

We sold our ONEOK stock investment in multiple transactions in February, August and November 2003 for total proceeds of $801.8 million, net of transaction costs. We recorded a pre-tax gain of $99.3 million. We used the net proceeds for repayment of our outstanding debt.

Discontinued Operations — Sale of Protection One and Protection One Europe

In 2003, we classified our monitored security businesses as discontinued operations. This is reflected in the accompanying consolidated financial statements. We also reclassified all historical periods to conform with this reclassification. These reclassifications were required by generally accepted accounting principles (GAAP) as a result of our board of directors’ approval of the Debt Reduction Plan. The amounts associated with our discontinued operations are included in our “Other” segment. See Note 29 of the Notes to Consolidated Financial Statements, “Segments of Business,” for further information relating to our “Other” segment.

We sold our interest in Protection One Europe on June 30, 2003. The sale resulted in a $58.7 million reduction in our consolidated debt level from the buyer’s assumption of $48.2 million of Protection One Europe debt that was included in our consolidated financial statements and the use of $10.5 million of cash proceeds to pay down debt.

On December 23, 2003 we signed a definitive agreement to sell our interests in Protection One to subsidiaries of Quadrangle Capital Partners LP and Quadrangle Master Funding Ltd. (together, Quadrangle). The transaction did not include the sale of our Protection One 7 $^{3}/_{8}$% senior notes due August 15, 2005 in the face amount of $26.6 million.

On February 17, 2004, we closed the sale of the Protection One stock owned by Westar Industries to Quadrangle and assigned to Quadrangle the senior credit facility between Westar Industries and Protection One, which had an outstanding balance at December 31, 2003 and at closing of $215.5 million. At closing, we received proceeds of $122.2 million. We could receive up to an additional $24.2 million of cash contingent on Quadrangle meeting post-closing investment objectives and an additional $15.0 million of cash upon our making additional payments to Protection One under a tax sharing agreement between us and Protection One. These contingent payments depend upon post-closing facts and circumstances and may not materialize in whole or in part and, if payable, may not be paid for a significant period of time after closing. The net cash proceeds from the transaction will be used to reduce debt.

Protection One has been part of our consolidated tax group since 1997. During that time, we have reimbursed Protection One for current tax benefits attributable to Protection One used in our consolidated tax return under the terms of a tax sharing agreement. Following the sale of our Protection One common stock on February 17, 2004, Protection One is no longer a part of our consolidated tax group. We and Protection One did not formally terminate our tax sharing agreement and, based on discussions with Protection One and its counsel, there are several areas of potential dispute between us regarding our obligations under the terms of the tax sharing agreement. The most material of these potential disputes involve (i) the proper treatment under the tax sharing agreement of tax obligations or benefits arising out of the transaction in which we sold our interest in Protection One, including the impact of the cancellation of indebtedness income generated by the assignment of a credit agreement for less than the full amount outstanding under the credit agreement at closing on future payments if any, to Protection One, (ii) whether any payments will be due to Protection One as a result of any tax benefits that may arise from a decision by us in the future to elect to treat the sale of our Protection One stock as a sale of assets under the Internal Revenue Code and (iii) whether payments due Protection One when we are subject to alternative minimum tax should be calculated at the alternative minimum tax rate of 20% or the normal statutory rate of 35%. Because of these potential disputes, we have provided for these matters in our consolidated financial statements. We nevertheless believe that we have strong positions with respect to each of these items and will aggressively pursue our positions. If we prevail, we may realize significant additional benefits, which may reduce future cash taxes and increase our reported net income.

Before classifying our monitored services businesses as discontinued operations, we were unable to record a tax benefit for a significant portion of the goodwill impairment and amortization charges and losses of our monitored services businesses recorded in prior years. Upon classification as discontinued operations, GAAP requires the current recognition of any tax benefit that will be realized in the foreseeable future, net of any required valuation allowance. We estimate the tax benefits associated with the capital loss on the sale of Protection One and the assignment of the senior credit facility with Protection One to be approximately $327.7 million. Based on the sale of our ONEOK investment and current projections of taxable income, we estimate that it is likely that we will be able to realize approximately $93.8 million of these tax benefits. Therefore, we have recorded a $233.9 million valuation allowance for that portion of the tax benefit that we estimate may be unrealizable in the foreseeable future.

With discontinued operations accounting, we were required to estimate the net realizable proceeds from the sale of our monitored services businesses. We used actual sale proceeds to calculate the loss from discontinued operations related to Protection One Europe, which resulted in a write off of $13.5 million. When we initially classified Protection One as discontinued operations in the first quarter of 2003, our estimate of the net realizable proceeds from the sale of Protection One was based on an independent appraisal. At that time, we recorded a write down of $41.6 million on our Protection One investment. We updated our estimates in the third quarter of 2003 based on then existing bids from potential buyers and took an additional write down of $165.6 million. Upon signing the definitive agreement with Quadrangle on December 23, 2003, we reduced our estimated net realizable proceeds by an additional $38.5 million to reflect actual proceeds, and wrote off that amount in the fourth quarter of 2003.

Call Option

In August 1998, we entered into a call option with an investment bank related to the issuance of $400.0 million of our 6.25% senior unsecured notes. These notes were putable and callable on August 15, 2003 (the putable/callable notes).

In the second quarter of 2003, we purchased a call option at a cost of $65.8 million, which locked in the settlement cost associated with the August 1998 call option. The outstanding options were settled and the related notes were retired in August 2003. For the year ended December 31, 2003, we recognized a loss related to the putable/callable notes of $21.5 million, which includes a loss of $14.2 million associated with the settlement of the call options.

Special Committee Investigation

In September 2002, our board of directors appointed a special committee of directors to investigate matters related to a federal grand jury subpoena served on us by the United States Attorney's Office in Topeka, Kansas, requesting information concerning the use of our corporate aircraft and our annual shareholder meetings. The scope of the special committee's investigation was expanded to cover other matters that were the subject of additional United States Attorney's Office subpoenas served on us and certain of our employees. These matters included executive compensation arrangements with David C. Wittig, our former chairman of the board, president and chief executive officer, and Douglas T. Lake, our former executive vice president, chief strategic officer and member of the board, and other former and present officers; the proposed rights offering of Westar Industries stock that was abandoned; and the company in general. The investigation also included matters that were the subject of a Securities and Exchange Commission (SEC) inquiry into the restatement of our first and second quarter 2002 consolidated financial statements and disclosures in our proxy statements concerning personal aircraft use by former officers and the payment of a bonus to Mr. Wittig in 2002. The special committee completed its investigation and publicly released a report on May 14, 2003 concerning the conclusions and recommendations reached as a result of the investigation. The investigation did not result in adjustments to our previously filed financial statements.

ELECTRIC UTILITY OPERATIONS

General

Westar Energy supplies electric energy at retail to approximately 346,000 customers in northeast Kansas, including the communities of Topeka, Lawrence, Manhattan, Salina and Hutchinson. KGE supplies electric energy at retail to approximately 298,000 customers in south-central and southeastern Kansas, including the city of Wichita. We classify our retail customers as residential, commercial and industrial as defined in our tariffs. We also supply electric energy at wholesale to the electric distribution systems of 55 Kansas cities and four rural electric cooperatives. We have contracts for the sale, purchase or exchange of wholesale electricity with other utilities. In addition, our energy marketing operations purchase and sell wholesale electricity in areas outside our historical service territory.

Generation Capacity

We have 5,904 megawatts (MW) of generating capacity, of which 2,596 MW, including Wolf Creek, is owned by KGE. See "Item 2. Properties" for additional information on our generating units. The capacity by fuel type is summarized below.

Fuel Type	Capacity (MW)	Percent of Total Capacity
Coal	3,335	56.5
Nuclear	548	9.3
Natural gas or oil	1,937	32.8
Diesel fuel	83	1.4
Wind	1	—
Total	5,904	100.0

Our aggregate 2003 peak system net load of 4,655 MW occurred on August 21, 2003. This is also our all-time peak system net load. Our net generating capacity combined with firm capacity purchases and sales provided a capacity margin of approximately 18% above system peak responsibility at the time of the peak. We do not anticipate needing additional generating capacity through at least 2006.

We have agreed to provide generating capacity to other utilities for certain periods as set forth below:

Utility	Capacity (MW)	Period Ending
Oklahoma Municipal Power Authority	60	December 2013
Midwest Energy, Inc.	130	May 2008
Midwest Energy, Inc.	125	May 2010
Empire District Electric Company	162	May 2010
McPherson Board of Public Utilities (McPherson)	(a)	May 2027

(a) We provide base load capacity to McPherson. McPherson provides peaking capacity to us. During 2003, we provided approximately 75 MW to, and received approximately 180 MW from, McPherson. The amount of base load capacity provided to McPherson is based on a fixed percentage of McPherson's annual peak system load.

Fossil Fuel Generation

Fuel Mix

The effectiveness of a fuel to produce heat is measured in British thermal units (Btu). The higher the Btu content of a fuel, the lesser quantity of the fuel it takes to produce electricity. The quantity of heat consumed during the generation of electricity is measured in millions of Btu (MMBtu).

Based on MMBtus, our 2003 actual fuel mix was 81% coal, 14% nuclear and 5% natural gas, oil or diesel fuel. We expect that our fuel mix in 2004 will have a higher percentage of nuclear usage since 2004 is not a refueling year at Wolf Creek. Our fuel mix fluctuates with the operation of Wolf Creek, as discussed below under "— Nuclear Generation," fluctuations in fuel costs, plant availability, customer demand and the cost and availability of wholesale market power.

Coal

Jeffrey Energy Center: The three coal-fired units at Jeffrey Energy Center have an aggregate capacity of 2,213 MW, of which we own an 84% share, or 1,859 MW. We have a long-term coal supply contract with Amax Coal West, Inc., a subsidiary of RAG America Coal Company, to supply coal to Jeffrey Energy Center from mines located in the Powder River Basin (PRB) in Wyoming. All of the coal used at Jeffrey Energy Center is purchased under this contract. The contract expires December 31, 2020. The contract contains a schedule of minimum annual MMBtu delivery quantities. The contract also contains a mechanism for repricing quantities received above the minimum annual delivery quantity. The price for these additional quantities is renegotiated every five years to provide a fixed price at current market prices. The first year affected by this repricing mechanism was 2003. The renegotiated price increased the cost of coal received in 2003 by approximately $3.0 million over the cost in the prior year.

The coal supplied to Jeffrey Energy Center during 2003 was surface mined and had an average Btu content of approximately 8,430 Btu per pound and an average sulfur content of 0.48 lbs/MMBtu (see "— Environmental Matters" for a discussion of sulfur content). The average delivered cost of coal burned at Jeffrey Energy Center during 2003 was approximately $1.21 per MMBtu, or $20.53 per ton.

Coal is transported from Wyoming under a long-term rail transportation contract with the Burlington Northern Santa Fe (BNSF) and Union Pacific railroads, with a term continuing through December 31, 2013.

LaCygne Generating Station: The two coal-fired units at LaCygne Generating Station (LaCygne) have an aggregate generating capacity of 1,362 MW, of which we own a 50% share, or 681 MW. LaCygne 1 uses a blended fuel mix containing approximately 85% PRB coal and 15% Kansas/Missouri coal. LaCygne 2 uses PRB coal. The operator of LaCygne, Kansas City Power & Light Company (KCPL), administers the coal and coal transportation contracts. All of the LaCygne 1 and LaCygne 2 PRB coal is supplied through fixed price contracts through 2005 and is transported under KCPL's Omnibus Rail Transportation Agreement with the BNSF and Kansas City Southern Railroad through December 31, 2010. The LaCygne 1 Kansas/Missouri coal is purchased from time to time from local Kansas and Missouri producers.

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The PRB coal supplied to LaCygne 1 and LaCygne 2 during 2003 had an average Btu content of approximately 8,658 Btu per pound and an average sulfur content of 0.38 lbs/MMBtu. During 2003, the average delivered cost of all coal burned at LaCygne 1 was approximately $0.85 per MMBtu, or $15.03 per ton. The average delivered cost of coal burned at LaCygne 2 was approximately $0.77 per MMBtu, or $13.17 per ton.

Lawrence and Tecumseh Energy Centers: The coal-fired units located at the Lawrence and Tecumseh Energy Centers have an aggregate generating capacity of 795 MW. We have a coal supply contract ending in December 2004 with Kennecott Coal Sales Company to supply PRB coal to Lawrence and Tecumseh Energy Centers. Approximately 62% of the coal used at these energy centers on an annual basis is purchased under this contract with the remainder purchased on the spot market. In 2003, the coal supplied to Lawrence and Tecumseh Energy Centers had an average Btu content of approximately 8,820 Btu per pound and an average sulfur content of 0.41 lbs/MMBtu. During 2003, the average delivered cost of all coal burned in the Lawrence units was approximately $1.01 per MMBtu, or $17.87 per ton. The average delivered cost of all coal burned in the Tecumseh units was approximately $1.02 per MMBtu, or $17.95 per ton.

The coal supplied to Lawrence and Tecumseh Energy Centers is transported from Wyoming by the BNSF railroad under a contract ending in December 2004. We expect to extend this contract through December 2006. We have received proposals for contracts to supply coal to Lawrence and Tecumseh Energy Centers for various terms and prices beyond 2005. We anticipate entering into one or more contracts by the end of the first quarter of 2004. Spot market coal may or may not be a part of the supply plan for years 2005 and beyond.

General: We have entered into all of our coal contracts in the ordinary course of business and do not believe we are substantially dependent on these contracts. We believe there are other suppliers with plentiful sources of coal available at spot market prices to replace, if necessary, fuel supplied pursuant to these contracts and that we would be able to make transportation arrangements for such coal. In the event that we were required to replace our coal agreements, we would not anticipate a substantial disruption of our business, although the cost of purchasing coal could increase. Because the majority of our coal needs are met through long-term contracts as discussed above, we do not anticipate being materially impacted by price changes in the coal spot market.

We have entered into all of our coal transportation contracts in the ordinary course of business. Although several rail carriers are capable of serving the coal mines from where our coal originates, several of our generating stations can be served by only one rail carrier. In the event the rail carrier to one of our generating stations fails to provide reliable service, we could experience a disruption of our business. However, due to the obligation of the rail carriers to provide service under the Interstate Commerce Act, we do not anticipate any substantial disruption of our business, although the cost of transporting coal could increase.

Natural Gas

We use natural gas either as a primary fuel or as a start-up/secondary fuel, depending on market prices, in our Gordon Evans, Murray Gill, Neosho, Abilene and Hutchinson Energy Centers, in the gas turbine units at our Tecumseh generating station and in the combined cycle units at the State Line facility. Natural gas is also used as a supplemental fuel in the coal-fired units at the Lawrence and Tecumseh generating stations. Natural gas for all facilities is purchased in the short-term spot market, which supplies our facilities with a flexible natural gas supply as necessary to meet operational needs. During 2003, we purchased 3.2 million MMBtu of natural gas on the spot market for a total cost of $16.3 million. Natural gas accounted for approximately 1% of our total fuel burned during 2003.

If natural gas prices are higher than the amount we are able to recover through our retail rates, we may be exposed to the increased natural gas cost and our exposure could be material. We may be able to reduce our exposure due to our ability to use other fuel types and by using other pricing techniques available to us, such as purchasing derivative contracts. To recover increased natural gas costs in excess of the cost included in retail rates, we would have to make a rate filing with the KCC or request a recovery mechanism through the KCC, which could be denied in whole or in part. For additional information on our exposure to commodity price risks, see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

Natural gas transportation for the Abilene and Hutchinson Energy Centers is maintained with Kansas Gas Service Company, a division of ONEOK. This contract expires April 30, 2004. We expect that we will be able to renegotiate this contract with similar terms. We meet a portion of our natural gas transportation requirements for the

Gordon Evans, Murray Gill, Neosho, Lawrence and Tecumseh Energy Centers through firm natural gas transportation capacity agreements with Southern Star Central Pipeline. All of the natural gas transportation requirements for the State Line facility are met through a firm natural gas transportation agreement with Southern Star Central Pipeline. The firm transportation agreements that serve the Gordon Evans, Murray Gill, Lawrence and Tecumseh Energy Centers extend through April 1, 2010. The agreement for the Neosho and State Line facilities extends through June 1, 2016.

Oil

Our Gordon Evans, Murray Gill, Neosho and Hutchinson Energy Centers have the capability to burn oil in addition to natural gas once the facilities have been started with natural gas. We use oil as an alternate fuel when economical or when interruptions to natural gas supply make it necessary. Because oil during 2003 was more economical than natural gas, we used oil as the primary fuel in these generating facilities for most of 2003. In addition, over the past few years, we have been able to sell more power at wholesale during the winter months when oil has typically been more economical than natural gas. During 2003, we purchased 10.3 million MMBtu of oil for a total cost of $33.5 million. Oil accounted for approximately 3% of our total fuel burned during 2003.

Oil is also used as a start-up fuel at some of our generating stations, as a primary fuel in the Hutchinson No. 4 combustion turbine and in the diesel generators. Oil is obtained by spot market purchases and longer-term contracts. We maintain quantities in inventory that we believe will meet our fuel switching needs to facilitate economic dispatch of power, for emergency requirements and to protect against reduced availability of natural gas for limited periods or when the primary fuel becomes uneconomical to burn.

Other Fuel Matters

Our contracts to supply fuel for our coal-fired and natural gas-fired generating units, with the exception of Jeffrey Energy Center, do not provide full fuel requirements at the various stations. Supplemental fuel is procured on the spot market to provide operational flexibility and to take advantage of economic opportunities when the price is favorable. We use financial instruments to hedge a portion of our anticipated fossil fuel needs in an attempt to offset the volatility of the spot market. In 2001, we designated certain derivative contracts entered into for natural gas as a cash flow hedge under Statement of Financial Accounting Standards (SFAS) No. 133. We discontinued accounting for these derivative contracts as a cash flow hedge at the end of 2003. Since we currently do not use hedge accounting for any financial instruments, any changes in the fair value of these instruments are recognized currently in earnings. Due to the volatility of the fuel markets, we are unable to determine what the value of these financial instruments will be when the agreements are actually settled. See “Item 7A. Quantitative and Qualitative Disclosures About Market Risk” for further information.

The table below provides information relating to the weighted average cost of fuel that we have used, which includes the commodity cost, transportation cost to our facilities and any other associated costs.

	2003	2002	2001
Per Million Btu:			
Nuclear	$ 0.39	$ 0.40	$ 0.44
Coal	1.07	1.05	1.08
Natural gas	5.01	3.84	3.79
Oil	3.24	2.58	3.65
Per MWh Generation	$12.10	$11.88	$12.42

Purchased Power

At times, we purchase power to meet the energy needs of our wholesale customers and to meet the requirements of the retail customers within our service territory. Factors that could cause us to purchase power for retail customers include generating plant outages, prices for wholesale energy, extreme weather conditions, growth, and other factors. If we were unable to generate an adequate supply of electricity for our retail customers, we would purchase power in the wholesale market to the extent it is available, subject to transmission constraints, and/or implement curtailment or interruption procedures as permitted by our tariffs and terms and conditions of service.

Nuclear Generation

Wolf Creek

Wolf Creek is a 1,166 MW nuclear power plant located near Burlington, Kansas. Wolf Creek began operation in 1985. KGE owns a 47% interest in Wolf Creek, or 548 MW, which represents 9.3% of our total generating capacity. KCPL also owns a 47% interest in Wolf Creek and a 6% interest is owned by a group of Kansas electric cooperatives. Wolf Creek is operated by WCNOC, a corporation owned by the co-owners of Wolf Creek. The co-owners pay the operating costs of WCNOC equal to their percentage ownership in Wolf Creek. WCNOC has approximately 1,000 employees.

Over the last three years, Wolf Creek contributed an average of 16% of our annual megawatt hours (MWh) generated while operating at an average capacity factor of approximately 92%. Wolf Creek has the lowest fuel cost per MWh generated of any of our generating units. An extended or unscheduled shutdown of Wolf Creek could have a substantial adverse effect on our business, financial condition and consolidated results of operations because of higher replacement power and other costs and reduced amounts of power to sell at wholesale.

Fuel Supply

Wolf Creek has on hand or under contract 84% of its uranium needs and 100% of its uranium conversion needs for 2004. In addition, 94% of the uranium and 100% of the uranium conversion required for operation of Wolf Creek through October 2009 is under contract. The balance of the 2004 uranium requirement is expected to be purchased on the spot market.

The owners have under contract 100% of the uranium enrichment required to operate Wolf Creek through March 2008. Fabrication requirements are under contract through 2024.

All uranium, uranium conversion and uranium enrichment arrangements, as well as the fabrication agreement, have been entered into in the ordinary course of business, and Wolf Creek ordinarily is not substantially dependent on these agreements. However, contraction and consolidation among suppliers of these commodities and services, coupled with recent temporary shutdowns of some production facilities of two of the suppliers, have introduced some uncertainty as to Wolf Creek’s ability to replace, if necessary, some of these contracts. We believe this potential problem is common to the nuclear industry. Accordingly, in the event the affected contracts were required to be replaced, Wolf Creek’s management believes that the industry and government would arrive at a solution to minimize disruption of the nuclear industry’s operations, including Wolf Creek’s operations.

Nuclear fuel is amortized to cost of sales based on the quantity of heat produced for the generation of electricity.

Radioactive Waste Disposal

Under the Nuclear Waste Policy Act of 1982, the Department of Energy (DOE) is responsible for the permanent disposal of spent nuclear fuel. Wolf Creek pays the DOE a quarterly fee for the future disposal of spent nuclear fuel. The fee is one-tenth of a cent for each kilowatt-hour of net nuclear generation produced. These disposal costs are included in the cost of sales.

A permanent disposal site will not be available for the nuclear industry until 2010 or later. Under current DOE policy, once a permanent site is available, the DOE will accept spent nuclear fuel on a priority basis. The owners of the oldest spent fuel will be given the highest priority. As a result, disposal services for Wolf Creek will not be available prior to 2016. Wolf Creek has on-site temporary storage for spent nuclear fuel. In early 2000, Wolf Creek completed replacement of spent fuel storage racks to increase its on-site storage capacity for all spent fuel expected to be generated by Wolf Creek through the end of its licensed life in 2025.

In mid-2002, Congress passed and the President signed a resolution approving the Yucca Mountain site in Nevada for the development of a nuclear waste repository for the disposal of spent nuclear fuel and high level nuclear waste from the nation's defense activities. This action allows the DOE to apply to the Nuclear Regulatory Commission (NRC) to license the project. The DOE expects that this facility will open in 2010. However, the opening of the Yucca Mountain site could be delayed due to litigation and other issues related to the site as a permanent repository for spent nuclear fuel.

Wolf Creek disposes of all classes of its low-level radioactive waste at existing third-party repositories. Should disposal capability become unavailable, Wolf Creek is able to store its low-level radioactive waste in an on-site facility. Wolf Creek believes that a temporary loss of low-level radioactive waste disposal capability will not affect continued operation of the power plant.

The Low-Level Radioactive Waste Policy Amendments Act of 1985 mandated that the various states, individually or through interstate compacts, develop alternative low-level radioactive waste disposal facilities. The states of Kansas, Nebraska, Arkansas, Louisiana and Oklahoma formed the Central Interstate Low-Level Radioactive Waste Compact (Compact), and the Compact Commission, which is responsible for causing a new disposal facility to be developed within one of the member states. The Compact Commission selected Nebraska as the host state for the disposal facility. WCNOC and the owners of the other five nuclear units in the Compact provided most of the pre-construction financing for this project. Our net investment in the Compact is approximately $7.4 million.

In December 1998, the Nebraska agencies responsible for considering the developer's license application denied the application. The license applicant sought a hearing on the license denial, but a United States District Court indefinitely delayed proceedings related to the hearing. Most of the utilities that had provided the project's pre-construction financing (including WCNOC) filed a federal court lawsuit contending Nebraska officials acted in bad faith while handling the license application. In September 2002, the court entered a $151.4 million judgment, about one-third of which constitutes prejudgment interest, in favor of the Compact Commission and against Nebraska, finding that Nebraska had acted in bad faith in handling the license application. On Nebraska's appeal, the 8th Circuit, United States Court of Appeals, upheld the District Court's decision in February 2004. Nebraska has sought further appellate court review of the decision.

By late summer 2004, Nebraska should no longer be a member of the Compact as a result of either its notice of voluntary withdrawal given in 1999 or the Compact Commission's 2003 revocation of the state's membership. Neither Nebraska's withdrawal from the Compact nor the Compact Commission's revocation of Nebraska's membership in the Compact will of themselves nullify the site license proceeding.

Outages

Wolf Creek operates on an 18-month refueling and maintenance outage schedule that permits operations during every third calendar year without interruption for a refueling outage. Wolf Creek was shut down for 45 days in 2003 for its 13th scheduled refueling and maintenance outage, which began on October 18, 2003 and ended on December 2, 2003. During the outage, a complete inspection of the reactor vessel head indicated no corrosion or other problems. During outages, our electric demand is met primarily by our fossil-fueled generating units and by purchasing power according to the most economical pricing and availability. As provided by the KCC, we amortize the incremental maintenance costs incurred for planned refueling outages evenly over the unit's operating cycle, normally 18 months. Wolf Creek is scheduled to be taken off-line in the spring of 2005 for its 14th refueling and maintenance outage.

An extended or unscheduled shutdown of Wolf Creek could have a substantial adverse effect on our business, financial condition and consolidated results of operations because of higher replacement power and other costs and reduced amounts of power to sell at wholesale. Although not expected, the NRC could impose an unscheduled plant shutdown due to security or other concerns.

Nuclear Decommissioning

Nuclear decommissioning is a nuclear industry term for the permanent shutdown of a nuclear power plant and the removal of radioactive components in accordance with NRC requirements. The NRC will terminate a plant's license and release the property for unrestricted use when a company has reduced the residual radioactivity of a nuclear plant to a level mandated by the NRC. The NRC requires companies with nuclear plants to prepare formal financial plans to fund nuclear decommissioning. These plans are designed so that funds required for nuclear decommissioning will be accumulated prior to the termination of the license of the related nuclear power plant.

We accrue nuclear decommissioning costs over the expected life of the Wolf Creek generating facility. The amount we accrue is based on the decommissioning costs approved by the KCC to be included in rates. Decommissioning costs that are recovered in rates are deposited in an external trust fund.

The KCC reviews nuclear decommissioning plans in two phases. Phase one is the approval of the nuclear decommissioning study, the current year dollar amount of funding and the future year dollar amount of funding. Phase two is the filing of a "funding schedule" by the owner of the nuclear facility detailing how it plans to fund the future year dollar amount for its pro rata share of the plant.

An updated nuclear decommissioning and dismantlement cost estimate was filed with the KCC on August 30, 2002. Estimated costs outlined by this study were developed to decommission Wolf Creek following a shutdown. The analyses relied on site-specific, technical information, updated to reflect current plant conditions and operating assumptions. Based on this study, our share of Wolf Creek's nuclear decommissioning costs, under the immediate dismantlement method, is estimated to be approximately $220.0 million in 2002 dollars. These costs include decontamination, dismantling and site restoration and are not inflated, escalated, or discounted over the period of expenditure. The actual nuclear decommissioning costs may vary from the estimates because of changes in technology and changes in costs for labor, materials and equipment.

The KCC issued an order on April 16, 2003 approving the August 2002 nuclear decommissioning study for Wolf Creek. On June 2, 2003, we filed a funding schedule with the KCC to reflect the KCC's April 16, 2003 order. On October 10, 2003, the KCC approved the funding schedule as filed without any change to our funding obligation.

Nuclear decommissioning costs are currently being charged to operating expense in accordance with the July 25, 2001 KCC rate order as modified by the KCC's approval of the funding schedule in the KCC's October 13, 2003 order. Electric rates charged to customers provide for recovery of these nuclear decommissioning costs over the life of Wolf Creek as determined by the KCC through 2045. The NRC requires that funds to meet its nuclear decommissioning funding assurance requirement be in our nuclear decommissioning fund by the time our license expires in 2025. We believe that the KCC approved funding level will be sufficient to meet the NRC minimum financial assurance requirement. However, our consolidated results of operations would be materially adversely affected if we are not allowed to recover the full amount of the funding requirement.

Nuclear decommissioning amounts expensed in 2003 approximated $3.9 million. The amounts collected are deposited in an external trust fund. The average after-tax expected return on trust assets is 5.7%.

Our investment in the nuclear decommissioning fund is recorded at fair value, including reinvested earnings. It approximated $80.1 million at December 31, 2003 and $63.5 million at December 31, 2002. Trust fund earnings accumulate in the fund balance and increase the recorded decommissioning liability.

Security

We have increased the level of security measures at our generation facility sites and various offices, due in part to nationwide concerns about homeland security. These measures include, but are not limited to, increased security personnel, patrolling of company property, restricting access to our properties and implementing emergency training and response procedures.

The NRC has issued orders to all nuclear plants that make our current security measures mandatory. The orders also impose new security requirements at United States nuclear power plants. Wolf Creek has complied with these requirements. There are additional requirements related to homeland security in the NRC orders that are required to be completed by October 29, 2004. Wolf Creek is working to meet that compliance deadline.

Competition and Deregulation

Electric utilities have historically operated in a rate-regulated environment. The Kansas Legislature and the KCC took no action on deregulation in 2003 or 2002, and we expect no action to be taken in the near future. The Federal Energy Regulatory Commission (FERC), the federal regulatory agency having jurisdiction over our wholesale rates and transmission services, and other utilities have initiated steps that are expected to result in a more competitive environment for utility services in the wholesale market.

The 1992 Energy Policy Act began deregulating the electricity market for generation. The Energy Policy Act permitted the FERC to order electric utilities to allow third parties to use their transmission systems to sell electric power to wholesale customers. In 1992, we agreed to open access of our transmission system for wholesale transactions. The FERC also requires us to provide transmission services to others under terms comparable to those we provide ourselves. In December 1999, the FERC issued an order (FERC Order No. 2000) encouraging formation of regional transmission organizations (RTOs). RTOs are designed to control the wholesale transmission services of the utilities in their regions, thereby facilitating open and more competitive markets in bulk power.

Southwest Power Pool

We are a member of the Southwest Power Pool (SPP). On October 15, 2003, the SPP filed an application with the FERC to be granted RTO status. The FERC granted SPP's application on February 10, 2004 subject to the SPP fulfilling certain specified requirements. If the SPP meets the requirements of the February 10, 2004 Order and obtains RTO status, we expect to be a member and turn operational control of our transmission system over to the SPP RTO under its membership agreement and applicable tariff. If approved, the SPP RTO will operate our transmission system as part of an interconnected transmission system across eight states. The SPP RTO will collect revenues attributable to the use of each member's transmission system. Members and transmission customers will be able to transmit power purchased, generated for sale or bought for resale in the wholesale market throughout the entire SPP RTO system. We believe each transmission owner generally retains the transmission capacity needed to serve its existing retail customers. Any additional transmission capacity will be sold on a first come/first served non-discriminatory basis. All transmission customers will be charged uniform rates for use of the transmission system, including entities that may sell power inside our certificated service territory. We do not expect that our participation in the SPP RTO will have a material effect on our operations; however, there will be increased costs due to establishment of the RTO and associated markets. At this time, it is difficult to quantify these costs because these market systems have not been fully designed and there are many implementation issues that remain unresolved, such as regulatory jurisdiction over bundled transmission rates. It is anticipated that these costs will be recovered through future increases in RTO charges.

Regulation and Rates

As a Kansas electric utility, we are subject to the jurisdiction of the KCC, which has general regulatory authority over our rates, extensions and abandonments of service and facilities, valuation of property, the classification of accounts, the issuance of some securities and various other matters. We are also subject to the jurisdiction of the FERC, which has authority over wholesale sales of electricity, the transmission of electric power and the issuance of some securities. We are subject to the jurisdiction of the NRC for nuclear plant operations and safety. We are exempt as a public utility holding company pursuant to the Public Utility Holding Company Act of 1935 from all provisions of that Act, except Section 9(a)(2), which relates to the acquisition of the securities of other utilities.

We will file a rate case with the KCC by May 1, 2005, based on a test year consisting of the 12 months ending December 31, 2004. Prior to May 1, 2005, we will not make a filing to increase our Kansas jurisdictional electric rates. Certain other parties have agreed not to file a rate complaint or motion for us to show cause why our rates should not be reduced.

Effective January 4, 2004, the United States government enacted legislation that revised the "Hours of Service" regulations that govern the length of time that drivers may operate vehicles and the length of time they must be off-duty. This legislation was designed to reduce accidents related to driver fatigue. Until September 2004, electric utilities are exempt from implementing these changes. During restoration of electric service after a severe storm or other major power outages, we have to obtain a declaration of a state of emergency in order to gain an exception to these rules. The exception would permit employees who are required to restore electric power to operate equipment for extended hours without the required off-duty time. The impact of this legislation could affect customer service and could result in increased operating costs if we have to hire additional employees or lengthen electric service outage periods.

On February 10, 2004, the National Electric Reliability Council (NERC) issued its anticipated reliability improvement initiatives that stem from investigations of the August 14, 2003 blackout in the Eastern United States. These initiatives will impact our operations in a number of ways, such as, system relay protection, vegetation management and operator training. NERC and the ten operating regions in the United States, including the SPP, are working together to determine what operating policies and planning standards changes are necessary to achieve the NERC's goals. Although it is difficult to ascertain potential costs at this time, it is likely that our annual capital and maintenance expenditure requirements will increase over the historic trends.

Additional information with respect to rate matters and regulation is set forth in Note 3 of the Notes to Consolidated Financial Statements, "Rate Matters and Regulation."

Environmental Matters

General

We are subject to various federal, state and local environmental laws and regulations. These laws and regulations primarily relate to discharges into the air and air quality, discharges of effluents into water and the use of water, and the handling and disposal of hazardous substances and wastes. These laws and regulations require a lengthy and complex process for obtaining licenses, permits and approvals from governmental agencies for our new, existing or modified facilities. If we fail to comply with such laws and regulations, we could be fined or otherwise sanctioned by regulators. In addition, under certain laws, we could be responsible for costs relating to contamination at our current and former facilities or at third-party waste disposal sites. We have incurred and will continue to incur capital and other expenditures to comply with environmental laws and regulations.

Environmental laws and regulations affecting power plants are overlapping, complex, subject to changes in interpretation and implementation and have tended to become more stringent over time. Although we believe that we can recover in rates costs relating to compliance with such laws and regulations, there can be no assurance that we will be able to recover all or any such increased costs from our customers or that our business, consolidated financial condition or results of operations will not be materially and adversely affected as a result of costs to comply with such existing and future laws and regulations.

Air Emissions

The Clean Air Act, state laws and implementing regulations impose, among other things, limitations on major pollutants, including SO2, particulate matter and nitrogen oxides (NOx).

Certain Kansas Department of Health and Environment regulations applicable to our generating facilities prohibit the emission of SO2 in excess of certain levels. In order to meet these standards, we use low-sulfur coal, fuel oil and natural gas and have equipped our generating facilities with pollution control equipment.

In addition, we must comply with the provisions of the Clean Air Act Amendments of 1990 that require a two-phase reduction in some emissions. We have installed continuous monitoring and reporting equipment in order to meet the acid rain requirements. We have not had to make any material capital expenditures to meet Phase II SO2 and NOx requirements.

Title IV of the Clean Air Act created an SO2 allowance and trading program as part of the federal acid rain program. Under the allowance and trading program, the United States Environmental Protection Agency (EPA) allocated annual SO2 emissions allowances for each affected emitting unit. An SO2 allowance is a limited authorization to emit one ton of SO2 during a calendar year. At the end of each year, each emitting unit must have enough allowances to cover its emissions for that year. Allowances are tradable so that affected units that are anticipated to emit SO2 in excess of their allowances may purchase allowances from affected units that are anticipated to emit SO2 in an amount less than their allowances. Because of strong demand for generation during

2002 and 2003, we consumed more SO_2 allowances than were allocated to us by the EPA. We made up the shortfall by buying allowances. In 2004 and future years, we may purchase SO_2 allowances as necessary in order to meet the acid rain requirements of the Clean Air Act.

On January 30, 2004, the EPA published two proposed air quality rules referred to as the "Interstate Air Quality Rule" and the "Utility Mercury Reduction Rule" that, if adopted, would impact our operations. In an attempt to address the impact of interstate transport of air pollutants on downwind states, the proposed Interstate Air Quality Rule would require reductions of SO_2 and NO_x in certain states, including Kansas, in two separate phases. The first reductions would be required in 2010 and the second in 2015.

The proposed Utility Mercury Reduction Rule sets out two approaches for requiring subject power plants to control mercury and nickel emissions. The first option, a traditional command and control approach, would require subject plants to meet Hazardous Air Pollutant emissions standards for mercury and nickel based on the application of maximum available control technology. The second option would establish standards of performance limiting mercury and nickel emissions, and include a "cap and trade" program for mercury emissions. The EPA is expected to issue its final rule in 2005. New requirements for reductions of nickel emissions will be applicable only to our generating facilities that burn a significant amount of heavy fuel oil. Based on currently available information, we cannot estimate our costs to comply with these two proposed rule changes, but these costs could be material.

We may be required to further reduce emissions of SO_2, NO_x, particulate matter, mercury and carbon dioxide (CO_2) as a result of various other current or pending laws, including, in particular:

- the EPA's national ambient air quality standards for particulate matter and ozone,
- the EPA's regional haze rules, designed to reduce SO_2, NO_x and particulate matter emissions, and
- additional legislation introduced in the past few years in Congress, such as the various "multi-pollutant" bills sponsored by members of Congress requiring reductions of CO_2, NO_x, SO_2 and mercury, and the President's "Clear Skies" legislation, which would cap emissions of three pollutants (NO_x, SO_2 and mercury).

Based on currently available information, we cannot estimate our costs to comply with these proposed laws, but such costs could be material.

EPA New Source Review

The EPA is conducting numerous investigations nationwide to determine whether modifications at coal-fired power plants are subject to New Source Review requirements or New Source Performance Standards under Section 114(a) of the Clean Air Act (Section 114). These investigations focus on whether projects at coal-fired plants were routine maintenance or whether the projects were substantial modifications that could have reasonably been expected to result in a significant net increase in emissions. The Clean Air Act requires companies to obtain permits and, if necessary, install control equipment to remove emissions when making a major modification or a change in operation if either is expected to cause a significant net increase in emissions.

The EPA has requested information from us under Section 114 regarding projects and maintenance activities that have been conducted since 1980 at the three coal-fired plants we operate. On January 22, 2004, the EPA notified us that certain projects completed at Jeffrey Energy Center violated pre-construction permitting requirements of the Clean Air Act.

We are in discussions with the EPA concerning this matter but are unable to predict whether the EPA will take further enforcement action. We will attempt to reach a settlement agreement with the EPA. However, if a settlement cannot be reached, the EPA could refer the matter to the United States Department of Justice for it to consider whether to pursue an enforcement action. If we are required to pay any fines or penalties or update or install emissions controls at Jeffrey Energy Center or the other coal-fired plants or take other remedial action, these costs could be material. We believe that costs related to updating or installing emissions controls would qualify for recovery through rates. If we are assessed a penalty as a result of the EPA's allegation, the penalty could be material and may not be recovered in rates.

Manufactured Gas Sites

We have been associated with a number of former manufactured gas sites located in Kansas and Missouri that may contain coal tar and other potentially harmful materials.

We and the Kansas Department of Health and Environment (KDHE) entered into a consent agreement in 1994 governing all future work at the Kansas sites. Under the terms of the consent agreement, we agreed to investigate and, if necessary, remediate these sites. Through December 31, 2003, the costs incurred for preliminary site investigation and risk assessment have been minimal. Pursuant to an environmental indemnity agreement with ONEOK, the current owner of some of the Kansas sites, our liability for twelve of the Kansas sites is limited. Of those twelve sites, ONEOK assumed total liability for remediation of seven sites and we share liability for remediation with ONEOK for five sites. Our total liability for the five shared sites is capped at $3.8 million and terminates in 2012. We have sole responsibility for remediation with respect to three Kansas sites. With respect to two of those sites, we are currently either conducting or completing remediation activities and, with respect to the third site, we will begin investigation activities in the near future.

Our liability for our former manufactured gas sites in Missouri is limited by an environmental indemnity agreement with Southern Union Company, which bought all of the Missouri manufactured gas sites. According to the terms of the agreement, our future liability for these sites is capped at $7.5 million and terminates in 2009.

Solid Waste Landfills

We have operating solid waste landfills at Jeffrey Energy Center, Tecumseh Energy Center and Lawrence Energy Center for the single purpose of disposing of coal combustion waste material. Additionally, there is one retired landfill at each of the Lawrence and Neosho Energy Centers. All landfills are permitted by the KDHE. The operating landfill at Lawrence Energy Center is projected to be full by 2007 requiring us to permit and construct a new landfill at this site. It is anticipated that the lead-time for permitting a new landfill may be significant. We began the process of obtaining this permit in late 2003 but can offer no assurance as to when or if we will obtain the permit.

SEGMENT INFORMATION

Financial information with respect to business segments is set forth in Note 29 of the Notes to Consolidated Financial Statements, “Segments of Business,” and is incorporated herein by reference.

GEOGRAPHIC INFORMATION

Geographic information is set forth in Note 29 of the Notes to Consolidated Financial Statements, “Segments of Business,” and is incorporated herein by reference.

EMPLOYEES

As of February 29, 2004, we had approximately 2,000 employees. Our current contract with Local 304 and Local 1523 of the International Brotherhood of Electrical Workers extends through June 30, 2005. The contract covered approximately 1,200 employees as of February 29, 2004.

ACCESS TO COMPANY INFORMATION

Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q and Current Reports on Form 8-K are available free of charge either through our website at www.wr.com or by responding to requests addressed to our investor relations department. These reports are available as soon as reasonably practicable after such material is electronically filed with or furnished to the SEC. The information contained on our website is not part of this document.

RISK FACTORS

Like other companies in our industry, our consolidated financial results will be impacted by weather, the economy of our service territory and the performance of our customers. Our common stock price and creditworthiness will be affected by national and international macroeconomic trends, general market conditions and the expectations of the investment community, all of which are largely beyond our control. In addition, the following statements highlight risk factors that may affect our consolidated financial condition and results of operations. These are not intended to be an exhaustive discussion of all such risks, and the statements below must be read together with factors discussed elsewhere in this document and in our other filings with the SEC.

Our Revenues Depend Upon Rates Determined by the KCC

The KCC regulates many aspects of our business and operations, including the retail rates that we may charge customers for electric service. Our retail rates are set by the KCC using a cost-of-service approach that takes into account our historical operating expenses, our fixed obligations and recovery of our capital investments, including potentially stranded obligations. Using this approach, the KCC sets rates at a level calculated to recover such costs, adjusted to reflect known and measurable changes, and a permitted return on investment. Other parties to a rate case or the KCC staff may contend that our current rates or rates proposed in the rate case are excessive. In July 2003, we entered into a Stipulation that requires us to file a rate case, which may or may not include a request for a change in rates, by May 1, 2005 and to pay customer rebates of $10.5 million on May 1, 2005 and $10.0 million on January 1, 2006. We agreed to the Stipulation and the required rebates to resolve matters related to the approval of our Debt Reduction Plan in a KCC proceeding, including assertions by some parties in the proceeding that our rates are excessive. The rates permitted by the KCC in the rate case will determine our revenues for the succeeding periods and may have a material impact on our consolidated earnings, cash flows and financial position, as well as our ability to maintain our common stock dividend at current levels or to increase our dividend in the future. We are unable to predict the outcome of the rate case.

Some of Our Costs May not be Fully Recovered in Retail Rates

Our rates, once established by the KCC, remain fixed until changed in a subsequent rate case. We may at any time elect to file a rate case to request a change in our rates or intervening parties may request that the KCC review our rates for possible adjustment, subject to any limitations that may have been ordered by the KCC. Earnings could be reduced to the extent that increases in our operating costs increase more than our revenues during the period between rate cases, which may occur because of maintenance and repair of plants, fuel and purchased power expenses, employee or labor costs, inflation or other factors.

Equipment Failures and Other External Factors Can Adversely Affect Our Results

The generation and transmission of electricity requires the use of expensive and complicated equipment. While we have a maintenance program in place, generating plants are subject to unplanned outages because of equipment failure. In these events, we must acquire power from others at unpredictable cost in order to supply our customers and perform our contractual agreements. This can increase our costs materially and prevent us from selling excess power at wholesale, thus reducing our profits. In addition, decisions or mistakes by other utilities may adversely affect our ability to use transmission lines to deliver or import power, thus subjecting us to unexpected expenses or to the cost and uncertainty of public policy initiatives. These factors, as well as weather, interest rates, economic conditions, fuel prices and price volatility, are largely beyond our control, but may have a material adverse effect on our consolidated earnings, cash flows and financial position.

Non-Investment Grade Credit Ratings May Increase Our Borrowing Costs

We are highly leveraged. At December 31, 2003, we had outstanding senior indebtedness of approximately $2.3 billion, consisting primarily of $1.4 billion of first mortgage bonds and debt secured by first mortgage bonds and $869.5 million of unsecured debt, including capital leases. First mortgage bonds are secured by a lien on substantially all of our utility property. A substantial portion of our senior debt is rated “less than investment grade” by the major rating services, which makes our cost of borrowing higher than it is for better rated companies. We have agreed with the KCC that we will reduce the proportion of our capital structure represented by debt from the December 31, 2003 level such that common equity becomes no less than 40% of our capitalization by December 31, 2004, but this may not cause the rating agencies to give us an “investment grade” rating. There can be no assurance that our ratings will be raised before we are required to refinance certain of our indebtedness that matures during the next few years.

We May Have a Material Financial Exposure Under the Clean Air Act and Other Environmental Regulations

On January 22, 2004, the EPA notified us that certain projects completed at Jeffrey Energy Center violated pre-construction permitting requirements under the Clean Air Act. This notification was delivered as part of an investigation by the EPA regarding maintenance activities that have been conducted since 1980 at the three coal-fired plants that we operate. If this matter is not resolved with the EPA, it may be referred to the United States Department of Justice for it to consider whether to pursue an enforcement action. The remedy for a violation could include fines and penalties and an order to install new emission control systems, the cost of which could be material.

Our activities are subject to stringent environmental regulation by federal, state, and local governmental authorities. These regulations generally involve effluents into the water, emissions into the air, the use of water, and hazardous substance and waste handling, remediation and disposal, among others. Congress also may consider legislation and the EPA may propose new regulations or change existing regulations that could require us to further restrict or reduce certain emissions at our plants. Legislation, proposed regulations or changes in regulations, if adopted, could impose additional costs on the operation of our power plants. Although we generally recover such costs through our rates, there can be no assurance that we would be able to recover all or any increased costs relating to compliance with environmental regulations from our customers or that our business, consolidated financial condition or results of operations would not be materially and adversely affected. We have made and will continue to make capital and other expenditures to comply with environmental laws and regulations. There can be no assurance that such expenditures will not have a material adverse effect on our business, consolidated financial condition or results of operations.

Competitive Pressures from Electric Industry Deregulation Could Adversely Affect Our Revenues and Reported Earnings

Neither the Kansas Legislature nor the KCC has taken action in the recent past to establish retail competition in our service territory. We currently apply the accounting principles of Statement of Financial Accounting Standards No. 71, “Accounting for the Effects of Certain Types of Regulation” (SFAS No. 71), to our regulated business and at December 31, 2003 had recorded $397.0 million of regulatory assets, net of regulatory liabilities. In the event that we determined that we could no longer apply the principles of SFAS No. 71, either as a result of the establishment of retail competition in Kansas or an expectation that permitted rates would not allow us to recover these costs, we would be required to record a charge against income in the amount of the remaining unamortized net regulatory assets.

We Face Financial Risks From Our Nuclear Facility

Risks of substantial liability arise from the ownership and operation of nuclear facilities, including, among others, structural problems at a nuclear facility, the storage, handling and disposal of radioactive materials, limitations on the amounts and types of insurance coverages commercially available and uncertainties with respect to the technological aspects of nuclear decommissioning at the end of their useful lives and anticipated increases in the cost of nuclear decommissioning and costs or measures associated with public safety. In the event of an extended or unscheduled outage at Wolf Creek, we would be required to purchase power in the open market to replace the power normally produced at Wolf Creek and we would have less power available for sale by us in the wholesale markets. Such purchases would subject us to the risk of increased energy prices and, depending on the length of the outage and the level of market prices, could adversely affect our cash flow. If we were not permitted by the KCC to recover these costs, such events could have an adverse impact on our consolidated financial condition.

We May Face Liability In Ongoing Lawsuits and Investigations

We and certain of our former and present directors and officers are defendants in civil litigation alleging violations of the securities laws. In addition, we continue to cooperate in investigations by a federal grand jury, the SEC and the United States Department of Justice into events at our company during the years prior to 2003. Our former president, chief executive officer and chairman and our former executive vice president and chief strategic officer have asserted significant claims against us in connection with the termination of their employment and the publication of the report of the special committee of our board. Finally, the FERC is investigating certain activities regarding our energy trading activities and our compliance with the FERC standards of conduct. An adverse result in any of these matters could result in damages, fines or penalties in amounts that could be material and adversely affect our consolidated results and financial condition.

Table of Contents

EXECUTIVE OFFICERS OF THE COMPANY

Name	Age	Present Office	Other Offices or Positions Held During the Past Five Years
James S. Haines, Jr.	57	Director, Chief Executive Officer and President (since December 2002)	**The University of Texas at El Paso -** Adjunct Professor and Skov Professor of Business Ethics (January 2002 to Present) **El Paso Electric Company -** Director, President and Chief Executive Officer (May 1996 to November 2001)
William B. Moore	51	Executive Vice President and Chief Operating Officer (since December 2002)	**Saber Partners, LLC -** Senior Managing Director and Senior Advisor (October 2000 to December 2002) **Westar Energy -** Executive Vice President, Chief Financial Officer and Treasurer (May 1999 to August 2000) Acting Executive Vice President, Chief Financial Officer and Treasurer (October 1998 to May 1999)
Mark A. Ruelle	42	Executive Vice President and Chief Financial Officer (since January 2003)	**Sierra Pacific Resources, Inc. -** President, Nevada Power Company (June 2001 to May 2002) Senior Vice President, Chief Financial Officer (March 1997 to May 2001)
Douglas R. Sterbenz	40	Senior Vice President, Generation and Marketing (since October 2001)	**Westar Energy, Inc. -** Senior Director, Bulk Power Marketing (January 1999 to October 2001)
Bruce A. Akin	39	Vice President, Administrative Services (since December 2001)	**Westar Energy Inc.** Executive Director, Business Services (October 2001 to December 2001) Executive Director, Human Resources (July 1999 to October 2001) Senior Director, Internal Audit (April 1998 to June 1999)
Kelly B. Harrison	45	Vice President, Regulatory (since December 2001)	**Westar Energy, Inc.** Executive Director, Regulatory (November 2001 to December 2001) Senior Director, Restructuring and Rates (October 1999 to October 2001) Director, Regulatory Services (January 1999 to September 1999)
Larry D. Irick	47	Vice President, General Counsel and Corporate Secretary (since February 2003)	**Westar Energy, Inc.** Vice President and Corporate Secretary (December 2001 to February 2003) Corporate Secretary (May 2000 to December 2001) Executive Director, Law (May 1999 to May 2000) **Bryan Cave, LLP** Counsel (July 1995 to May 1999)
Peggy S. Loyd	46	Vice President, Corporate Compliance and Internal Audit (since March 2003)	**Westar Energy, Inc.** Vice President, Financial Services (May 2000 to March 2003) Executive Director, Financial Services (January 1999 to May 2000)
James J. Ludwig	45	Vice President, Public Affairs (since January 2003)	**Westar Energy, Inc.** Senior Director, Regulatory Affairs (July 1995 to October 2001)

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ITEM 2. PROPERTIES

ELECTRIC UTILITY FACILITIES

Name	Location	Unit No.	Year Installed	Principal Fuel	Unit Capacity (MW) By Owner: Westar Energy	KGE	Total Company
Abilene Energy Center:	Abilene, Kansas						
Combustion Turbine		1	1973	Gas	71.0	—	71.0
Gordon Evans Energy Center:	Colwich, Kansas						
Steam Turbines		1	1961	Gas—Oil	—	147.0	147.0
		2	1967	Gas—Oil	—	383.0	383.0
Combustion Turbines		1	2000	Gas—Oil	75.0	—	75.0
		2	2000	Gas—Oil	77.0	—	77.0
		3	2001	Gas—Oil	151.0	—	151.0
Diesel Generator		1	1969	Diesel	—	3.0	3.0
Hutchinson Energy Center:	Hutchinson, Kansas						
Steam Turbines		1	1950	Gas	17.0	—	17.0
		2	1950	Gas	18.0	—	18.0
		3	1951	Gas	28.0	—	28.0
		4	1965	Gas	175.0	—	175.0
Combustion Turbines		1	1974	Gas	54.0	—	54.0
		2	1974	Gas	54.0	—	54.0
		3	1974	Gas	54.0	—	54.0
		4	1975	Diesel	77.0	—	77.0
Diesel Generator		1	1983	Diesel	3.0	—	3.0
Jeffrey Energy Center (84%):	St. Marys, Kansas						
Steam Turbines		1(a)	1978	Coal	471.0	147.0	618.0
		2(a)	1980	Coal	470.0	147.0	617.0
		3(a)	1983	Coal	475.0	149.0	624.0
Wind Turbines		1(a)	1999	—	0.5	0.1	0.6
		2(a)	1999	—	0.5	0.1	0.6
LaCygne Station (50%):	LaCygne, Kansas						
Steam Turbines		1(a)	1973	Coal	—	344.0	344.0
		2(b)	1977	Coal	—	337.0	337.0
Lawrence Energy Center:	Lawrence, Kansas						
Steam Turbines		3	1954	Coal	57.0	—	57.0
		4	1960	Coal	122.0	—	122.0
		5	1971	Coal	388.0	—	388.0
Murray Gill Energy Center:	Wichita, Kansas						
Steam Turbines		1	1952	Gas—Oil	—	42.0	42.0
		2	1954	Gas—Oil	—	69.0	69.0
		3	1956	Gas—Oil	—	104.0	104.0
		4	1959	Gas—Oil	—	107.0	107.0
Neosho Energy Center:	Parsons, Kansas						
Steam Turbine		3	1954	Gas—Oil	—	69.0	69.0
State Line (40%):	Joplin, Missouri						
Combined Cycle		2-1(a)	2001	Gas	66.0	—	66.0
		2-2(a)	2001	Gas	64.0	—	64.0
		2-3(a)	2001	Gas	72.0	—	72.0
Tecumseh Energy Center:	Tecumseh, Kansas						
Steam Turbines		7	1957	Coal	85.0	—	85.0
		8	1962	Coal	143.0	—	143.0
Combustion Turbines		1	1972	Gas	20.0	—	20.0
		2	1972	Gas	20.0	—	20.0
Wolf Creek Generating Station (47%):	Burlington, Kansas						
Nuclear		1(a)	1985	Uranium	—	548.0	548.0
Total					3,308.0	2,596.2	5,904.2

(a) We jointly own Jeffrey Energy Center (84%), LaCygne 1 generating unit (50%), Wolf Creek Generating Station (47%) and State Line (40%). Total unit capacity amounts reflect Westar Energy's ownership only.

(b) In 1987, we entered into a sale-leaseback transaction involving our 50% interest in the LaCygne 2 generating unit.

We own approximately 6,100 miles of transmission lines, approximately 25,200 miles of overhead distribution lines and approximately 3,200 miles of underground distribution lines.

Substantially all of our utility properties are encumbered by first priority mortgages pursuant to which bonds have been issued and are outstanding.

ITEM 3. LEGAL PROCEEDINGS

Information on our legal proceedings is set forth in Notes 3, 17, 19, 20, 21 and 23 of the Notes to Consolidated Financial Statements, "Rate Matters and Regulation," "Commitments and Contingencies — EPA New Source Review," "Legal Proceedings," "Ongoing Investigations," "Special Committee Investigation," and "Potential Liabilities to David C. Wittig and Douglas T. Lake," respectively, which are incorporated herein by reference.

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

No matter was submitted to a vote of our security holders through the solicitation of proxies or otherwise during the fourth quarter of 2003.

PART II

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

STOCK TRADING

Our common stock is listed on the New York Stock Exchange and traded under the ticker symbol WR. As of February 23, 2004, there were 31,721 common shareholders of record. For information regarding quarterly common stock price ranges for 2003 and 2002, see Note 30 of the Notes to Consolidated Financial Statements, "Quarterly Results (Unaudited)."

DIVIDENDS

Holders of our common stock are entitled to dividends when and as declared by our board of directors. However, prior to the payment of common dividends, we must first pay dividends to the holders of preferred stock based on the fixed dividend rate for each series, and we must meet our obligations with respect to mandatorily redeemable preferred securities issued by an affiliated trust.

Quarterly dividends on common stock and preferred stock are normally paid on or about the first business day of January, April, July and October to shareholders of record as of or about the ninth day of the preceding month. Our board of directors reviews our common stock dividend policy from time to time. Among the factors the board of directors considers in determining our dividend policy are earnings, cash flows, capitalization ratios, regulation, including the KCC's order requiring us to reduce our outstanding debt, competition and financial loan covenants. On February 9, 2004, our board of directors declared a first-quarter 2004 dividend of $0.19 per share. We established our dividend at this level in the first quarter of 2003.

On March 4, 2004, our board of directors announced its current intention to begin restoring our dividend to a level consistent with comparable regulated electric utilities following achievement of the Debt Reduction Plan. Subject to a review of our financial results and dividend policy at the time, the board currently anticipates that it will increase the quarterly dividends payable in January 2005.

Our Articles of Incorporation restrict the payment of dividends or the making of other distributions on our common stock while any preferred shares remain outstanding unless certain capitalization ratios and other conditions are met. We provide further information on these restrictions in Note 22 of the Notes to Consolidated Financial Statements, "Common and Preferred Stock." We do not expect these restrictions to have an impact on our ability to pay dividends on our common stock.

For additional information on dividends, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Future Cash Requirements," Note 3 of the Notes to Consolidated Financial Statements, "Rate Matters and Regulation" and Note 22, "Common and Preferred Stock," included herein.

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ITEM 6. SELECTED FINANCIAL DATA

	For the Year Ended December 31,				
	2003	2002 (a)	2001	2000	1999 (b)
	(In Thousands)				
Income Statement Data:					
Sales	$ 1,461,143	$ 1,423,151	$ 1,308,536	$ 1,361,006	$ 1,257,435
Income from continuing operations before accounting change and preferred dividends	162,915	88,816	59,333	192,696	80,848
Earnings (loss) available for common stock	84,042	(793,400)	(21,771)	135,352	13,167

	As of December 31,				
	2003	2002	2001	2000	1999 (b)
	(In Thousands)				
Balance Sheet Data:					
Total assets	$ 5,734,505	$ 6,740,325	$ 7,712,764	$ 7,882,867	$ 7,981,238
Long-term debt, net, and shares subject to mandatory redemption	2,259,879	3,225,556	2,915,153	2,938,832	2,419,459

	For the Year Ended December 31,				
	2003	2002 (a)	2001	2000	1999 (b)
Common Stock Data:					
Basic earnings per share available for common stock from continuing operations before accounting change	$ 2.24	$ 1.23	$ 0.83	$ 2.78	$ 1.19
Basic earnings (losses) per share available for common stock	$ 1.16	$ (11.06)	$ (0.31)	$ 1.96	$ 0.20
Dividends per share	$ 0.76	$ 1.20	$ 1.20	$ 1.44	$ 2.14
Book value per share	$ 13.93	$ 13.37	$ 25.64	$ 27.28	$ 27.68
Average shares outstanding (in thousands)	72,429	71,732	70,650	68,962	67,080

(a) See Note 5 of the Notes to Consolidated Financial Statements, “Discontinued Operations — Sale of Protection One and Protection One Europe” for discussion of impairment charges that are the primary cause of our losses.

(b) Information reflects the impairment of marketable securities and the change to an accelerated amortization method for the monitored services segment’s customer accounts.

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

INTRODUCTION

We are the largest electric utility in Kansas. We produce, transmit and sell electricity at retail in Kansas and at wholesale in a multi-state region in the central United States under the regulation of the KCC and the FERC.

Our goals are to improve our core utility business by improving customer service, continuing to expand our wholesale sales, continuing to reduce debt, improving credit quality and improving our relationships with regulators, shareholders, employees and other interested parties.

Our focus during 2003 was the reduction of debt, primarily through the disposition of non-utility and non-core operations. In 2003, we reduced our debt by $965.7 million primarily through use of the proceeds from the sale of our ONEOK stock and through the retirement of $135.0 million of debt that was economically defeased in 2002. With the closing of the sale of our interest in Protection One on February 17, 2004, we received proceeds of $122.2 million, which will also be used to reduce debt. We plan to issue $100 million to $250 million of equity during 2004.

Key factors affecting our business in any given period include the weather, the economic well-being of our Kansas service territory, performance of our electric generating facilities, conditions in fuel markets and the markets for wholesale electricity and the cost of dealing with public policy initiatives.

As discussed in Note 32 to the Notes to Consolidated Financial Statements, "Restatement of Cash Flow Statements," the consolidated statements of cash flows for the years ended December 31, 2003, 2002 and 2001 have been restated to correct misstatements in the classification of cash distributions received from investments in foreign power projects, the reinvestment of dividends payable on shares of our common stock issued or reissued under our Direct Stock Purchase Plan and other individually insignificant items. Amounts affected by this restatement included in "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources" have been appropriately revised.

As you read Management's Discussion and Analysis, please refer to our consolidated financial statements and the accompanying notes, which contain our operating results.

CRITICAL ACCOUNTING ESTIMATES

Our discussion and analysis of financial conditions and results of operations are based on our consolidated financial statements, which have been prepared in conformity with GAAP. Note 2 of the Notes to Consolidated Financial Statements, "Summary of Significant Accounting Policies," contains a summary of our significant accounting policies, many of which require the use of estimates and assumptions by management. The policies highlighted below have an impact on our reported results that may be material due to the levels of judgment and subjectivity necessary to account for uncertain matters or susceptibility of matters to change.

Pension Benefit Plans

In accounting for our retirement plans and other post-retirement benefits, we make assumptions regarding the valuation of benefit obligations and the performance of plan assets. The reported costs of our pension benefit plans, which include our portion of WCNOC's costs, are impacted by management estimates regarding earnings on plan assets, contributions to the plan, discount rates used to determine our projected benefit obligation and pension costs and employee demographics (including age, compensation levels and employment periods). A change in any of these assumptions could have a significant impact on future costs, which may be reflected as an increase or decrease in net income in the period, or on the amount of related liabilities reflected on our consolidated balance sheets or may also require cash contributions.

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The following table shows the annual impact of a 0.5% decrease in certain assumptions. If the discount rate increased by 0.5%, the impact would be a similar amount in the opposite direction.

	Change in Assumption	Annual Increase in Projected Benefit Obligation	Annual Increase in Pension Liability	Annual Increase in Projected Pension Expense
			(In Thousands)	
Discount rate	0.5% decrease	$ 25,209	$ 36,572	$ 1,107
Rate of return on plan assets	0.5% decrease	—	—	2,300

Revenue Recognition - Energy Sales

Revenues from energy sales are recognized upon delivery to the customer and include an estimate for energy delivered but unbilled at the end of each year. Our estimate of revenue attributable to this unbilled portion is based on the total energy available for sale during the year measured against total billed sales and our estimates, based on historical data, of the portion of the unbilled revenues attributable to each of our different rate classes (retail or wholesale). If actual sales differ from the estimate, our revenues could be affected. At December 31, 2003, we had estimated unbilled revenue of $42.7 million.

Energy marketing activities are accounted for under the mark-to-market method of accounting. Under this method, changes in the portfolio value are recognized as gains or losses in the period of change. The net mark-to-market change is included in energy sales on our consolidated statements of income (loss). The resulting unrealized gains and losses are recorded as energy trading assets and liabilities on our consolidated balance sheets. We use quoted market prices to value our energy marketing and derivative contracts when such data are available. When market prices are not readily available or determinable, we use alternative approaches, such as model pricing. The quoted market prices used to value these transactions reflect our best estimate of fair values of our trading positions. Results actually achieved from these activities could vary materially from intended results and could affect our consolidated financial results.

The tables below show fair value of energy trading contracts outstanding for the year ended December 31, 2003, their sources and maturity periods:

	Fair Value of Contracts
	(In Thousands)
Net fair value of contracts outstanding at the beginning of the period	$ 9,643
Less contracts realized or otherwise settled during the period	29,376
Plus fair value of new contracts entered into during the period	30,197
Fair value of contracts outstanding at the end of the period	$ 10,464

The sources of the fair values of the financial instruments related to these contracts are summarized in the following table:

	Fair Value of Contracts at End of Period				
	Total Fair Value	Maturity Less Than 1 Year	Maturity 1-3 Years	Maturity 4-5 Years	Maturity in Excess of 5 Years
			(In Thousands)		
Sources of Fair Value					
Prices actively quoted (futures)	$ 5,615	$ 5,615	$ —	$ —	$ —
Prices provided by other external sources (swaps and forwards)	6,554	3,475	3,079	—	—
Prices based on the Black Option Pricing model (options and other) (a)	(1,705)	(1,705)	—	—	—
Total fair value of contracts outstanding	$ 10,464	$ 7,385	$ 3,079	$ —	$ —

(a) The Black Option Pricing model is a variant of the Black-Scholes Option Pricing model.

OPERATING RESULTS

Westar Energy Consolidated

We are pursuing a strategy to return to our core business of providing electric service. We have discussed our 2003 significant accomplishments elsewhere throughout this document. As described in further detail in the "—Segments of Business" discussion that follows, our operating results for 2003 improved based on a variety of factors.

2003 compared to 2002:

Income from operations improved 35% from $274.3 million in 2002 to $371.4 million in 2003. Improved electric sales revenues and the significant decline in selling, general and administrative expense more than offset increased fuel and purchased power expense. Administrative expenses in 2002 were significantly higher due to expenses related to work force reductions and other costs described below. Other income increased by $59.4 million in 2003 because the gain on the sale of our ONEOK stock in 2003 more than offset other declines in investment earnings, losses associated with the settlement of the call option related to our putable/callable notes and losses on the extinguishment of debt. Interest expense declined primarily due to the reduction in our outstanding debt balance. The 2003 results of discontinued operations were significantly improved as compared to 2002. Results in 2002 were adversely impacted by large impairment charges, which are described below. The net effect of these improvements in our consolidated financial position was net income of $85.0 million in 2003 compared to a net loss of $793.0 million in 2002.

2002 compared to 2001:

Income from operations improved 30% from $211.0 million in 2001 to $274.3 million in 2002. Improved electric sales revenues and declines in purchased power and depreciation expenses more than offset increases in administrative expenses related to special committee and grand jury investigation costs, work force reductions and amounts recorded for potential liabilities to Mr. Wittig and Mr. Lake. Additionally, results of discontinued operations more than offset the improvement in our income from operations. In 2002, we recorded impairment charges of $623.7 million, net of $72.3 million tax, associated with goodwill and customer account assets of our monitored services businesses. These large impairment charges are reflected in the results of our discontinued operations and are the primary reason for our net loss of $793.4 million in 2002.

Segments of Business

We evaluate segment performance based on earnings per share and have two reportable segments: "Electric Utility" and "Other." We have no single customer from which we receive 10% or more of our revenues.

- "Electric Utility" consists of our integrated electric utility operations, including the generation, transmission and distribution of power to our retail customers in Kansas and to wholesale customers, as well as our energy marketing activities.

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- "Other" includes our former ownership interests in ONEOK, Protection One and Protection One Europe and other investments that in the aggregate are immaterial to our business or consolidated results of continuing operations. We expect the "Other" segment will be immaterial in future periods.

Electric Utility

Regulated electric utility sales are significantly impacted by such things as rate regulation, customer conservation efforts, wholesale demand, the overall economy of our service area, the weather and competitive forces. Our wholesale sales are impacted by demand inside and outside our service territory, the cost of fuel and purchased power, price volatility and available generation capacity.

2003 compared to 2002: Changes in results of operations for the "Electric Utility" segment are as follows:

	Year Ended December 31,			
	2003	2002	Change	% Change
	(In Thousands, Except Per Share Amounts)			
SALES:				
Residential	$ 432,955	$ 442,106	$ (9,151)	(2.1)
Commercial	382,585	385,375	(2,790)	(0.7)
Industrial	240,538	242,847	(2,309)	(1.0)
Subtotal	1,056,078	1,070,328	(14,250)	(1.3)
Network integration (a)	59,587	60,136	(549)	(0.9)
Other (b)	46,915	46,689	226	0.5
Total retail	1,162,580	1,177,153	(14,573)	(1.2)
Energy Marketing	31,129	7,049	24,080	341.6
Wholesale	267,434	238,697	28,737	12.0
Total Sales	1,461,143	1,422,899	38,244	2.7
OPERATING EXPENSES:				
Fuel used for generation	342,522	347,332	(4,810)	(1.4)
Purchased power	47,790	32,123	15,667	48.8
Operating and maintenance	375,115	378,812	(3,697)	(1.0)
Depreciation and amortization	167,226	171,749	(4,523)	(2.6)
Selling, general and administrative	153,329	213,823	(60,494)	(28.3)
Total Operating Expenses	1,085,982	1,143,839	(57,857)	(5.1)
INCOME FROM OPERATIONS	375,161	279,060	96,101	34.4
OTHER INCOME (EXPENSE):				
Investment earnings	8,303	2,118	6,185	292.0
Settlement of putable/callable notes	(14,221)	—	(14,221)	—
Other income	5,180	1,237	3,943	318.8
Other expense	(16,590)	(38,380)	21,790	56.8
Total Other Income (Expense)	(17,328)	(35,025)	17,697	50.5
Interest expense	193,369	229,760	(36,391)	(15.8)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES AND PREFERRED DIVIDENDS	164,464	14,275	150,189	1,052.1
Income tax expense (benefit)	51,050	(5,785)	56,835	982.5
NET INCOME	113,414	20,060	93,354	465.4
Preferred dividends, net of gain on reacquired preferred stock	968	399	569	142.6
EARNINGS AVAILABLE FOR COMMON STOCK	$ 112,446	$ 19,661	$ 92,785	471.9
EARNINGS PER SHARE	$ 1.55	$ 0.27	$ 1.28	

(a) **Network Integration:** Reflects a network transmission tariff as discussed in "— Other Information — Electric Utility — Network Integration Transmission Service." In 2003, our transmission costs were approximately $65.3 million. This amount, less $5.7 million that was retained by the SPP as administration cost, was returned to us as revenues. In 2002, our transmission costs were approximately $65.9 million with an administration cost of $5.8 million retained by the SPP.

(b) **Other:** Includes public street and highway lighting, miscellaneous electric revenues and revenues to be refunded.

The following table reflects changes in electric sales volumes, as measured by thousands of MWh of electricity, for the two years ended December 31, 2003 and 2002. No sales volumes are shown for network integration or energy marketing because these activities are unrelated to electricity we generate.

	2003	2002	Change	% Change
	(Thousands of MWh)			
Residential	6,031	6,170	(139)	(2.3)
Commercial	6,801	6,817	(16)	(0.2)
Industrial	5,448	5,451	(3)	(0.1)
Other	104	106	(2)	(1.9)
Total retail	18,384	18,544	(160)	(0.9)
Wholesale	8,666	9,115	(449)	(4.9)
Total	27,050	27,659	(609)	(2.2)

Assets attributable to our “Electric Utility” segment are summarized in the table below:

	December 31,			
	2003	2002	Change	% Change
	(In Thousands)			
Identifiable assets	$ 4,970,380	$ 5,087,004	$(116,624)	(2.3)

Retail sales revenues declined primarily because of the effect of the weather on usage of electricity by residential customers, which caused residential sales volumes to decline, as well as the sale of a small portion of our rural distribution territory. Commercial and industrial sales revenues showed slight decreases while sales volumes remained relatively flat compared to 2002. The decline in retail sales volumes accounted for approximately $10.2 million of the decline in retail sales revenues. The remainder of the decline in retail sales revenues was due to the accrual of approximately $3.5 million to be refunded to customers in 2005 and 2006 pursuant to a KCC order.

The increases in energy marketing and wholesale sales revenues more than offset the decline in retail sales revenues. Higher wholesale market prices were the primary cause of improvement in energy marketing and wholesale sales revenues. The higher wholesale market prices more than offset the decline in wholesale sales volumes.

Purchased power expenses increased $15.7 million during 2003. During periods of high energy use in 2003, we purchased more power from other sources than we did during the same periods of 2002 because it was more economical to purchase power than to operate our peaking units. This is also the primary reason our fuel expense decreased.

Selling, general and administrative expenses declined in 2003, which reflects a reduction in numerous incremental administrative expenses incurred in 2002. These 2002 administrative expenses included a $36.0 million charge related to our work force reduction, a $9.0 million charge related to an exchange of restricted share units for common stock and an expense of $22.9 million for potential liabilities to Mr. Wittig and Mr. Lake. The decline in selling, general and administrative expenses for 2003 was partially offset by $9.6 million in charges related to the special committee and grand jury investigations in 2003 as compared to charges of $4.7 million in 2002 related to these investigations.

Decreases in depreciation and amortization and operating and maintenance expenses also contributed to the decline in total operating expenses for 2003. Depreciation and amortization expense decreased due primarily to the adoption of new depreciation rates on April 1, 2002 pursuant to a KCC order. Operating and maintenance expense declined due primarily to the $11.9 million gain recorded on the sale of utility assets, which was recorded as an offset to operating expenses. General maintenance expenses at our generating facilities increased by $8.5 million, partially offsetting the decline in operating expenses.

Other income (expense) improved significantly in 2003 primarily because the mark to market charge to record the fair value of the call option associated with the putable/callable notes for 2003 was $2.2 million compared to a charge of $22.6 million for 2002. The smaller mark to market charge in 2003 was the result of the settlement of the call options related to our putable/callable notes in August 2003.

On November 8, 2002, the KCC issued an order that directed us to reverse all transactions recorded in 2002 as equity investments by us in Westar Industries so such transactions were reflected as intercompany payables owed by Westar Industries to us. During 2003, as a result of the November 8, 2002 KCC order, we recorded interest income associated with the intercompany receivable owed by Westar Industries to Westar Energy. This resulted in an offset to interest expense in 2003 of $30.8 million as compared to $5.6 million in 2002. The remainder of the improved interest expense was due to the significant decline in our outstanding debt balances. In response to a subsequent KCC order, the intercompany receivable owed by Westar Industries to Westar Energy was again reclassified as an equity investment by us in Westar Industries. No additional interest income is expected to be recorded in the future.

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2002 compared to 2001: Changes in results of operations for the "Electric Utility" segment are as follows:

	Year Ended December 31,			
	2002	2001	Change	% Change
	(In Thousands, Except Per Share Amounts)			
SALES:				
Residential	$ 442,106	$ 419,492	$ 22,614	5.4
Commercial	385,375	380,277	5,098	1.3
Industrial	242,847	244,392	(1,545)	(0.6)
Subtotal	1,070,328	1,044,161	26,167	2.5
Network integration (a)	60,136	—	60,136	—
Other (b)	46,689	50,669	(3,980)	(7.9)
Total retail	1,177,153	1,094,830	82,323	7.5
Energy Marketing	7,049	10,258	(3,209)	(31.3)
Wholesale	238,697	202,089	36,608	18.1
Total Sales	1,422,899	1,307,177	115,722	8.9
OPERATING EXPENSES:				
Fuel used for generation	347,332	347,351	(19)	—
Purchased power	32,123	46,725	(14,602)	(31.3)
Operating and maintenance	378,812	343,253	35,559	10.4
Depreciation and amortization	171,749	185,156	(13,407)	(7.2)
Selling, general and administrative	213,823	168,073	45,750	27.2
Total Operating Expenses	1,143,839	1,090,558	53,281	4.9
INCOME FROM OPERATIONS	279,060	216,619	62,441	28.8
OTHER INCOME (EXPENSE):				
Investment earnings	2,118	2,986	(868)	(29.1)
Other income	1,237	2,809	(1,572)	(56.0)
Other expense	(38,380)	(15,514)	(22,866)	(147.4)
Total Other Income (Expense)	(35,025)	(9,719)	(25,306)	(260.4)
Interest expense	229,760	228,129	1,631	0.7
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES, ACCOUNTING CHANGE AND PREFERRED DIVIDENDS	14,275	(21,229)	35,504	167.2
Income tax expense (benefit)	(5,785)	(40,018)	34,233	85.5
INCOME FROM CONTINUING OPERATIONS BEFORE ACCOUNTING CHANGE AND PREFERRED DIVIDENDS	20,060	18,789	1,271	6.8
Cumulative effect of accounting change	—	18,694	(18,694)	—
NET INCOME	20,060	37,483	(17,423)	(46.5)
Preferred dividends, net of gain on reacquired preferred stock	399	895	(496)	(55.4)
EARNINGS AVAILABLE FOR COMMON STOCK	$ 19,661	$ 36,588	$ (16,927)	(46.3)
EARNINGS PER SHARE	$ 0.27	$ 0.52	$ (0.25)	

(a) **Network Integration:** Reflects a network transmission tariff as discussed in "— Other Information — Electric Utility — Network Integration Transmission Service." In 2002, our transmission costs were approximately $65.9 million with an administration cost of $5.8 million retained by the SPP. 2002 was the first year this tariff was in effect.

(b) **Other:** Includes public street and highway lighting, miscellaneous electric revenues and revenues to be refunded.

The following tables reflect changes in electric sales volumes, as measured by thousands of MWh of electricity, for the two years ended December 31, 2002 and 2001. No sales volumes are shown for network integration or energy marketing because these activities are unrelated to electricity we generate.

	2002	2001	Change	% Change
	(Thousands of MWh)			
Residential	6,170	5,755	415	7.2
Commercial	6,817	6,742	75	1.1
Industrial	5,451	5,617	(166)	(3.0)
Other	106	107	(1)	(0.9)

Total retail	18,544	18,221	323	1.8
Wholesale	9,115	7,547	1,568	20.8
Total	27,659	25,768	1,891	7.3

Assets attributable to our "Electric Utility" segment are summarized in the table below:

	December 31,			
	2002	2001	Change	% Change
	(In Thousands)			
Identifiable assets	$ 5,087,004	$ 4,879,641	$ 207,363	4.2

Residential sales revenues increased due primarily to the increase in residential sales volumes. The increase was due primarily to favorable weather conditions but was partially offset by lower retail rates. The lower retail rates are attributable to the rate reductions ordered by the KCC in July 2001.

Commercial sales revenues were similarly affected by favorable weather conditions, the increased volumes and the lower retail rates. Industrial sales revenues decreased primarily because of weak economic conditions experienced in our service territory, principally associated with the downturn in the aircraft industry.

Other retail revenues, which include public street and highway lighting and miscellaneous electric revenues, also decreased. The factors affecting this decline were a $1.9 million provision for rate refunds recorded during 2002 and a $1.9 million decline in other electric revenues, primarily related to changes in transmission revenues received as a result of open access to our transmission lines.

Wholesale revenues increased primarily as a result of an increase in wholesale sales volumes. Revenues attributable to the increase in wholesale sales volumes were partially offset by lower market prices. Energy marketing revenues declined due primarily to the lower market prices.

Purchased power expense decreased due primarily to lower wholesale market prices. The remainder of the decline is due to a decrease in the quantity purchased because of the increased availability of our generating units.

Selling, general and administrative expenses increased due primarily to $22.9 million recorded in 2002 for potential liabilities to Mr. Wittig and Mr. Lake, $12.2 million increase in 2002 as compared to 2001 for employee severance costs related to a work force reduction, $9.0 million in 2002 for compensation expense associated with an exchange of previously granted restricted share units, as discussed in Note 15 of the Notes to Consolidated Financial Statements, "Employee Benefit Plans — Stock Based Compensation Plans," and approximately $4.7 million in 2002 for special committee and grand jury investigation costs.

Operating and maintenance expense increased due primarily to $65.9 million in charges associated with the network integration transmission tariff as discussed in "— Other Information — Electric Utility — Network Integration Transmission Service." Our maintenance expense declined $22.6 million, or 19%, due primarily to the lower forced outage rates at our generating units, which partially offset the increase in transmission expense.

The increases in selling, general and administrative expenses and operating and maintenance expenses were partially offset by a decline in depreciation expense. Depreciation expense declined $13.4 million due primarily to a change in depreciation rates on April 1, 2002.

We had higher other expense in 2002 due to recording the $22.6 million mark to market charge to record the fair value of the call option associated with the putable/callable notes.

Other

Other includes our former ownership interests in ONEOK, Protection One and Protection One Europe and other investments which are, in the aggregate, immaterial to our business or consolidated results of continuing operations.

2003 compared to 2002: Changes in results of operations for our “Other” segment are as follows:

	For the years ended December 31,			
	2003	2002	Change	% Change
	(In Thousands)			
SALES	$ —	$ 252	$ (252)	—
OPERATING EXPENSES	3,763	5,033	(1,270)	(25.2)
INCOME (LOSS) FROM OPERATIONS	(3,763)	(4,781)	1,018	21.3
OTHER INCOME (EXPENSE):				
Investment earnings	28,429	74,974	(46,545)	(62.1)
Gain on ONEOK Stock	99,327	—	99,327	—
(Loss) on extinguishment of debt	(12,234)	(1,541)	(10,693)	(693.9)
Impairment of investments	(500)	(330)	(170)	(51.5)
Other income	—	112	(112)	—
Other expense	(53)	—	(53)	—
Total Other Income (Expense)	114,969	73,215	41,754	57.0
Interest expense (income)	30,987	5,412	25,575	472.6
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	80,219	63,022	17,197	27.3
Income tax expense (benefit)	30,718	(5,734)	36,452	635.7
INCOME FROM CONTINUING OPERATIONS	49,501	68,756	(19,255)	(28.0)
Results of discontinued operations, net of tax	(77,905)	(881,817)	803,912	91.2
EARNINGS (LOSS) AVAILABLE FOR COMMON STOCK	$ (28,404)	$ (813,061)	$ 784,657	96.5
EARNINGS (LOSS) PER SHARE	$ (0.39)	$ (11.33)	$ 10.94	

Sales revenues shown for 2002 were from a wholly owned subsidiary of Westar Industries providing paging services. The subsidiary was sold during the first quarter of 2002.

Other income increased in 2003 as compared to 2002 due primarily to the gain of $99.3 million recorded on the sale of ONEOK stock. This gain was partially offset by a reduction in investment earnings, of which $30.5 million was due to the cessation of dividends and equity earnings on the ONEOK shares we sold. Investment earnings in 2003 were also lower than in 2002 because of the one-time payment of approximately $14.2 million received during the first quarter of 2002 as a partial recovery of an investment in a foreign power project. A $7.3 million charge on the mark to market adjustment on the call option of the putable/callable notes also affected the increase in the loss on extinguishment of debt.

Interest expense increased primarily as the result of intercompany interest expense of $30.8 million paid to Westar Energy in 2003 that was not paid in 2002. This interest expense was recorded as a result of the November 8, 2002 KCC order as discussed in the “Electric Utility” segment above.

The $77.9 million loss on discontinued operations for 2003 includes impairment charges of $137.1 million, net of tax benefit of $108.6 million, on our monitored services businesses that was based on actual sale proceeds received on the sale of our interest in Protection One Europe and the estimate of value that we believed would be recovered in connection with a sale of our interest in Protection One. This compares to an $881.8 million loss on discontinued operations for 2002, which included impairment charges of $623.7 million, net of $72.3 million tax benefit, related to the impairment recorded in 2002 for goodwill and customer account assets.

Assets attributable to our “Other” segment are summarized in the table below:

	December 31,			
	2003	2002	Change	% Change
	(In Thousands)			
Identifiable assets	$ 764,125	$ 1,653,321	$(889,196)	(53.8)

The change in identifiable assets is due primarily to recording our investment in the monitored services businesses at the estimate of realizable value and the sale of ONEOK stock.

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2002 compared to 2001: Changes in results of operations for our “Other” segment are as follows:

	For the years ended December 31,			
	2002	2001	Change	% Change
	(In Thousands)			
SALES	$ 252	$ 1,359	$ (1,107)	(81.5)
OPERATING EXPENSES	5,033	6,943	(1,910)	(27.5)
INCOME (LOSS) FROM OPERATIONS	(4,781)	(5,584)	803	14.4
OTHER INCOME (EXPENSE):				
Investment earnings	74,974	49,648	25,326	51.0
(Loss) gain on extinguishment of debt	(1,541)	1,395	(2,936)	(210.5)
Impairment of investments	(330)	(11,075)	10,745	97.0
Other income	112	7,364	(7,252)	(98.5)
Total Other Income (Expense)	73,215	47,332	25,883	54.7
Interest expense (income)	5,412	(12,102)	17,514	144.7
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	63,022	53,850	9,172	17.0
Income tax expense (benefit)	(5,734)	13,306	(19,040)	(143.1)
INCOME FROM CONTINUING OPERATIONS	68,756	40,544	28,212	69.6
Results of discontinued operations, net of tax	(881,817)	(98,903)	(782,914)	(791.6)
EARNINGS (LOSS) AVAILABLE FOR COMMON STOCK	$ (813,061)	$ (58,359)	$ (754,702)	(1,293.2)
EARNINGS (LOSS) PER SHARE	$ (11.33)	$ (0.83)	$ (10.50)	

Sales revenues shown above were from a wholly owned subsidiary of Westar Industries providing paging services. The subsidiary was sold during the first quarter of 2002.

Investment earnings increased $25.3 million in 2002 primarily as a result of the receipt of a one-time payment of approximately $14.2 million related to a partial recovery of an investment in a foreign power project and an increase in ONEOK investment income of $4.9 million. In 2001, we recorded an $11.1 million impairment charge to recognize an other than temporary decline in fair value of certain securities held for investment. Other income in 2001 is attributable to a favorable arbitration panel decision regarding the settlement of a liability related to an investment in a foreign power project.

Westar Industries recorded interest income of $12.6 million in 2001 received in association with an intercompany note that it did not receive in 2002.

As discussed above, the substantial impairment charges recorded in 2002 were the primary reasons for the increase in 2002 loss on discontinued operations.

Assets attributable to our “Other” segment are summarized in the table below:

	December 31,			
	2002	2001	Change	% Change
	(In Thousands)			
Identifiable assets	$1,653,321	$2,833,123	$(1,179,802)	(41.6)

The change in identifiable assets is due primarily to recording the impairment charges on the goodwill and customer account assets of our monitored services businesses in 2002.

LIQUIDITY AND CAPITAL RESOURCES

Overview

We believe we will have sufficient cash to fund future operations of our business, debt reductions, the rebates to customers we are required to make in 2005 and 2006, and the payment of dividends, from a combination of cash on hand, cash flow and available borrowing capacity under our revolving credit facility and access to capital markets. Uncertainties affecting our ability to meet these requirements include, among others, factors affecting sales described above, economic conditions, including the impact of inflation on operating expenses, regulatory actions, conditions in the capital markets, our ability to implement the Debt Reduction Plan, including the issuance of additional Westar Energy common stock and compliance with environmental regulations.

As of December 31, 2003, our total outstanding long-term debt, excluding current maturities, was approximately $2.1 billion. At December 31, 2003, our current maturities of long-term debt were $190.7 million, due primarily to the reclassification of $184.5 million of debt that matures in August 2004 from long-term to short-term debt. Our indebtedness could have a negative impact on, among other things, our ability to obtain additional financing in the future for working capital, capital expenditures and general corporate purposes and our ability to withstand a downturn in our business or the economy in general.

Capital Resources

We had $79.6 million in unrestricted cash and cash equivalents at December 31, 2003. We consider cash equivalents to be highly liquid investments with maturities of three months or less at the time they are purchased.

At December 31, 2003, we also had $17.9 million of restricted cash classified as a current asset and $31.9 million of restricted cash classified as a long-term asset. The following table details our restricted cash as of December 31, 2003:

	Restricted Cash Current Portion	Restricted Cash Long-term Portion
	(In Thousands)	
Prepaid capacity and transmission agreement	$ 2,090	$ 28,239
Cash held in escrow as required by certain letters of credit, surety bonds and various other deposits	15,835	3,615
Total	$ 17,925	$ 31,854

We had $149.0 million of available borrowing capacity under our revolving credit facility at December 31, 2003. We plan to replace our existing $150.0 million revolving credit facility, which matures on June 6, 2005, with a new $300.0 million revolving credit facility in the first quarter of 2004.

The Debt Reduction Plan provides for a systematic disposal of our non-utility and non-core assets and the planned issuance of equity securities. The net proceeds of these transactions have been and will be used to reduce debt. We may reduce debt pursuant to terms stated in the debt agreements or through open market purchases or tender offers.

The Westar Energy mortgage prohibits additional first mortgage bonds from being issued (except in connection with certain refundings) unless Westar Energy's unconsolidated net earnings available for interest, depreciation and property retirement (which as defined, does not include earnings or losses attributable to the ownership of securities of subsidiaries), for a period of 12 consecutive months within 15 months preceding the issuance, are not less than the greater of twice the annual interest charges on, and 10% of the principal amount of, all first mortgage bonds outstanding after giving effect to the proposed issuance. In addition, the issuance of bonds is subject to limitations based on the amount of bondable property additions. As of December 31, 2003, $361.3 million principal amount of additional first mortgage bonds could be issued under the most restrictive provisions in the mortgage, except in connection with refundings.

The KGE mortgage prohibits additional first mortgage bonds from being issued (except in connection with certain refundings) unless KGE's net earnings before income taxes and before provision for retirement and depreciation of property for a period of 12 consecutive months within 15 months preceding the issuance are not less than either two and one-half times the annual interest charges on, or 10% of the principal amount of, all KGE first mortgage bonds outstanding after giving effect to the proposed issuance. In addition, the issuance of bonds is subject to limitations based on the amount of bondable property additions. As of December 31, 2003, approximately $889.0 million principal amount of additional KGE first mortgage bonds could be issued under the most restrictive provisions in the mortgage.

We expect to issue equity securities in 2004 in private transactions, public offerings or both.

Cash Flows from Operating Activities

Our primary source of operating cash flows is the operations of our electric utility business. Cash flows from operating activities decreased $144.6 million to $126.4 million in 2003 from $271.0 million in 2002. This decrease was mostly attributable to taxes paid in 2003 of $53.6 million compared to an income tax refund received in 2002 of $54.1 million, an increase in maintenance expenditures at our generating facilities in 2003 as compared to 2002, and increased legal expenditures in 2003 related to investigations and litigation. The increased taxes paid in 2003 were mostly attributable to the gain on the sale of ONEOK stock.

Cash flows from operating activities increased $153.1 million to $271.0 million in 2002 from $117.9 million in 2001. This increase was mostly attributable to a decrease in maintenance expenditures in 2002 over 2001 and an income tax refund received in 2002 of $54.1 million. Severance payments of $27.6 million related to workforce reductions made in 2002 compared to $4.3 million in severance payments made in 2001 offset the increase.

Cash Flows from (used in) Investing Activities

In general, cash used for investing purposes relates to the growth and maintenance of the operations of our electric utility business. The utility business is capital intensive and requires significant investment in plant on an annual basis. We spent $150.4 million in 2003, $126.8 million in 2002, and $227.0 million in 2001 on net additions to utility property, plant and equipment, which included $52.2 million in 2001 for new generation facilities. We did not construct any new generation facilities in 2002 or 2003.

During 2003, we received net proceeds of $801.8 million from the sale of ONEOK stock and net proceeds of $33.3 million from the sale of utility assets. Proceeds from other investments includes ONEOK dividends, proceeds from the sale of investments in affordable housing tax credit limited partnerships and proceeds from the sale of other miscellaneous investments.

Cash Flows (used in) from Financing Activities

We used $876.0 million of cash in 2003 for financing activities compared to $73.8 million in 2002. In 2003, cash was used in financing activities for the retirement of long-term debt and the payment of dividends. In 2003, we reduced our indicated annual dividend from $1.20 per share to $0.76 per share.

In 2002, an increase in long-term debt was due primarily to the debt refinancings completed during 2002, and was the principal source of cash flows from financing activities that were used to reduce short-term debt, retire other long-term debt, place funds in a trust to be used for debt repayment, pay dividends, acquire treasury stock and retire a portion of our preferred stock.

We received net cash flows from financing activities of $132.6 million in 2001. In 2001, an increase in short-term debt was the principal source of cash flows from financing activities. Cash from financing activities was used to fund the retirement of long-term debt and to pay dividends.

Future Cash Requirements

The Debt Reduction Plan requires us to pay rebates to retail customers of $10.5 million on May 1, 2005 and $10.0 million on January 1, 2006. We believe we can fund these rebates with internally generated cash flow and available borrowing capacity under the revolving credit facility.

If we are required to update emissions controls or take other remedial action as a result of the EPA's investigation, the costs could be material. We may also have to pay fines or penalties or make significant capital or operational expenditures related to the notice of violation we received from the EPA in connection with certain projects completed at the Jeffrey Energy Center. In addition, significant capital or operational expenditures may be required in order to comply with future environmental regulations or in connection with future remedial obligations.

Our business requires significant capital investments. Through 2006, we expect we will need cash mostly for ongoing utility construction programs designed to improve facilities providing electric service. Other than making planned upgrades to existing facilities, we do not anticipate needing additional generating capacity through at least 2006. We expect these cash needs to be met with internally generated cash flow.

Electric utility capital expenditures for 2003 and anticipated capital expenditures for 2004 through 2006 are as follows:

	Replacements	Additional Capacity	New Customer Construction	Nuclear Fuel	Total Electric Utility
			(In Thousands)		
2003	$ 90,949	$ 1,140	$ 37,448	$20,841	$ 150,378
2004	112,409	9,270	37,403	21,346	180,428
2005	127,163	14,743	37,814	1,086	180,806
2006	140,046	7,990	38,419	22,638	209,093

These estimates are prepared for planning purposes and will be revised from time to time. Actual expenditures will differ from our estimates. These amounts do not include any estimate of expenditures that may be incurred as a result of the EPA investigation or other enacted or proposed environmental regulations.

Maturities of long-term debt as of December 31, 2003 are as follows:

Year	Principal Amount
	(In Thousands)
2004	$ 190,747
2005	183,395
2006	103,879
2007	755,489
2008	2,732
Thereafter	1,023,637
	$ 2,259,879

We have $184.5 million of debt that matures in August 2004. We expect to repay this debt from a combination of cash on hand, available borrowing capacity and, if completed prior to such time, the proceeds of equity issuances.

Contractual Obligations and Commercial Commitments

In the course of our business activities, we enter into a variety of contractual obligations and commercial commitments. Some of these result in direct obligations reflected on our consolidated balance sheets while others are commitments, some firm and some based on uncertainties, not reflected in our underlying consolidated financial statements. The obligations listed below do not include amounts for on-going needs for which no contractual obligations existed as of December 31, 2003, and represent only those amounts that we were contractually obligated to meet as of December 31, 2003. We may from time to time enter into new contracts to replace contracts that have expired.

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Contractual Cash Obligations

The following table summarizes the projected future cash payments for our contractual obligations existing at December 31, 2003:

	Total	2004	2005 - 2006 (b)	2007 - 2008	Thereafter
			(In Thousands)		
Contractual Obligations					
Long-term debt excluding capital leases (a)	$ 2,237,286	$ 185,940	$ 279,666	$ 752,914	$ 1,018,766
Capital leases (c)	25,328	5,294	8,473	6,039	5,522
Adjusted long-term debt	2,262,614	191,234	288,139	758,953	1,024,288
Operating leases (d)	614,310	45,106	99,203	104,367	365,634
Fossil fuel (e)	1,991,748	176,653	323,266	243,512	1,248,317
Nuclear fuel (f)	177,904	23,710	25,338	22,856	106,000
Unconditional purchase obligations	30,984	20,557	10,419	7	1
Total contractual obligations, including adjusted long-term debt	$ 5,077,560	$ 457,260	$ 746,365	$ 1,129,695	$ 2,744,240

(a) Final maturity of January 1, 2005 or later. See Note 12 of the Notes to Consolidated Financial Statements, “Long-Term Debt,” for individual long-term debt maturities.
(b) We have an obligation to pay rebates to customers in 2005 and 2006.
(c) Includes principal and interest on capital leases for vehicles and computer equipment.
(d) Includes office space, operating facilities, office equipment and operating equipment.
(e) Coal and natural gas commodity and transportation contracts.
(f) Uranium concentrates, conversion and enrichment.

Commercial Commitments

The following table summarizes our commercial commitments by date of expiration existing at December 31, 2003:

	Total Amounts Committed	2004	2005 - 2006	2007 - 2008	Thereafter
			(In Thousands)		
Commercial Commitments					
Lines of credit (a)	$ 1,000	$ —	$ 1,000	$ —	$ —
Outstanding letters of credit (b)	10,709	9,509	—	1,200	—
Total commercial commitments	$ 11,709	$ 9,509	$ 1,000	$ 1,200	$ —

(a) Revolving credit facility capacity totaling $150.0 million with borrowings as of December 31, 2003 of $1.0 million.
(b) $2.7 million related to our energy marketing and trading activities, $5.8 million related to worker’s compensation and $2.2 million related to other operating activities.

Debt Covenants

Some of our debt instruments contain restrictions that require us to maintain various coverage and leverage ratios as defined in the agreements. Our calculations of these ratios are performed in accordance with our debt agreements and are used solely to determine compliance with our various debt covenants. We were in compliance with these covenants as of December 31, 2003.

Accounts Receivable Sales Program

On July 28, 2000, Westar Energy and KGE entered into an agreement with WR Receivables Corporation, a wholly owned, bankruptcy-remote special purpose entity (SPE) to sell all of their accounts receivable arising from the sale of electricity to the SPE. These transfers are accounted for as sales in accordance with SFAS No. 140, “Accounting for Transfers and Servicing of Financial Assets and Extinguishment of Liabilities.” The SPE then sells up to $125 million of an undivided interest in the accounts receivable to a third party conduit under various terms and conditions. The percentage ownership interest in receivables held by the third party conduit will increase or decrease over time, depending on the characteristics of the SPE's receivables, including delinquency rates and debtor concentrations. The agreement with the third party conduit is renewable annually upon agreement by all parties. On July 23, 2003, the term of the agreement was extended through July 21, 2004.

See Note 6 of the Notes to Consolidated Financial Statements, "Accounts Receivable and Variable Interest Entities," for additional information regarding our SPE transactions.

Consolidation of Variable Interest Entities

In January 2003, the Financial Accounting Standards Board (FASB) issued Financial Interpretation Number (FIN) 46, "Consolidation of Variable Interest Entities," which was subsequently revised in December 2003 with the issuance of FIN 46R. See Note 6 of the Notes to Consolidated Financial Statements, "Accounts Receivable and Variable Interest Entities" for additional information.

Debt Financings

On May 10, 2002, we completed offerings for $365.0 million of our first mortgage bonds and $400.0 million of our unsecured senior notes. The entire principal amount of these securities will be due on May 1, 2007. The first mortgage bonds bear interest at an annual rate of 7 $^{7}/_{8}$% and the unsecured senior notes bear interest at an annual rate of 9 $^{3}/_{4}$%. Interest on the first mortgage bonds and unsecured senior notes is payable semi-annually on May 1 and November 1 of each year. The net proceeds from these offerings were used to repay outstanding indebtedness of $547.0 million under our existing secured bank term loan, provide for the repayment of $100.0 million of our 7.25% first mortgage bonds due August 15, 2002 together with accrued interest, reduce the outstanding balance on our existing secured revolving credit facility and pay fees and expenses of the transactions. In conjunction with our May 10, 2002 financing, we amended our secured revolving credit facility to reduce the total commitment under the facility to $400.0 million from $500.0 million and to release $100.0 million of our first mortgage bonds from collateral.

On June 6, 2002, we entered into a secured credit agreement providing for a $585.0 million term loan and a $150.0 million revolving credit facility, each maturing on June 6, 2005, provided that if we have not refinanced or provided for the payment of our 6.875% senior unsecured notes (with an outstanding principal balance of $184.5 million) before June 1, 2004, the secured credit agreement will mature on June 1, 2004. All loans under the credit agreement are secured by KGE's first mortgage bonds. The proceeds of the term loan were used to retire the existing $400.0 million revolving credit facility with an outstanding principal balance of $380.0 million, to provide for the repayment at maturity of $135.0 million principal amount of KGE first mortgage bonds that were due December 15, 2003 together with accrued interest, to repurchase approximately $45.0 million of our outstanding unsecured notes and to pay customary fees and expenses of the transactions.

In February 2004, we repaid the remaining balance of $114.1 million under our $585.0 million term loan that was due in 2005 with internally generated cash and a portion of the proceeds received from the sale of Protection One.

Interest Rate Swap

Effective October 4, 2001, we entered into a $500.0 million interest rate swap agreement with a term of two years. At that time, the effect of the swap agreement was to fix the annual interest rate on a term loan at 6.18%. In June 2002, we refinanced the term loan associated with this swap, which increased the effective rate of the swap to 6.43%. At December 31, 2002, the variable rate in effect for the term loan was 4.40%. We settled the swap agreement on September 29, 2003. For information regarding ongoing interest rates, see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

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Capital Structure

Our consolidated capital structure at December 31, 2003 and 2002 was as follows:

	2003	2002
Common equity	31%	23%
Preferred stock	1%	1%
Long-term debt	68%	76%
Total	100%	100%

Equity Issuance Plans

We plan to issue $100 million to $250 million of equity during 2004 in private transactions, public offerings or both. The Debt Reduction Plan requires that we have at least 40% common equity in our capital structure at December 31, 2004. As of December 31, 2003, our consolidated common equity ratio was 31%.

Credit Ratings

Standard & Poor’s Ratings Group (S&P), Moody’s Investors Service (Moody’s) and Fitch Investors Service (Fitch) are independent credit-rating agencies that rate our debt securities. These ratings indicate the agencies’ assessment of our ability to pay interest and principal when due on our securities.

On December 19, 2003, Moody’s assigned us a speculative liquidity rating of SGL-3, which reflects its view that we have “adequate” liquidity. On January 5, 2004, S&P affirmed its ratings for us and KGE and revised its outlook for us from developing to positive. On March 1, 2004 Fitch raised its ratings for us and KGE and assigned us a stable outlook.

As of March 1, 2004, ratings with these agencies are as follows:

	Westar Energy Mortgage Bond Rating	Westar Energy Unsecured Debt	KGE Mortgage Bond Rating
S&P	BBB-	BB-	BB+
Moody’s	Ba1	Ba2	Ba1
Fitch	BBB-	BB+	BBB-

In general, less favorable credit ratings make debt financing more costly and more difficult to obtain on terms that are economically favorable to us. Westar Energy and KGE do not have any credit rating conditions in any of the agreements under which our debt has been issued, except for conditions in the agreements governing the sale of our accounts receivable discussed in Note 6 of the Notes to Consolidated Financial Statements, “Accounts Receivable and Variable Interest Entities.” We may enter into new credit agreements that contain credit conditions, which could affect our liquidity and/or our borrowing costs.

New Accounting Pronouncements

Accounting for Energy Trading Contracts

In May 2003, the FASB issued SFAS No. 149, “Amendment of Statement 133 on Derivative Instruments and Hedging Activities.” SFAS No. 149 amends the accounting for derivative instruments, including certain derivative instruments embedded in other contracts for hedging activities, and clarifies which contracts qualify as “normal purchase/normal sale” contracts. SFAS No. 149 also amends certain other existing pronouncements and requires contracts with comparable characteristics to be accounted for similarly. In particular, SFAS No. 149 clarifies when a contract with an initial net investment meets the characteristics of a derivative and when a derivative that contains a financing component will require special reporting in the statement of cash flows. SFAS No. 149 was effective for contracts entered into or modified after June 30, 2003. Adoption of SFAS No. 149 has not had a material effect on our consolidated results of operations, financial position or cash flows.

In October 2002, the FASB, through the Emerging Issues Task Force (EITF), reached consensus on EITF Issue No. 02-03, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities." EITF Issue No. 02-03, in part, rescinded Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities." As a result, all new contracts entered into after October 25, 2002 can no longer be marked-to-market and recorded in earnings unless they fall within the scope of SFAS No. 133. We were unaffected by this change in accounting principle and were not required to reclassify any of our contracts since our energy trading contracts qualify as derivative instruments under the guidance of SFAS No. 133. EITF Issue No. 02-03 also requires reporting energy trading contracts and derivatives in the income statement on a net basis effective January 1, 2003, whether the contracts are settled financially or physically. We began classifying our energy trading contracts on a net basis during the third quarter of 2002 and have reclassified all prior periods to reflect this presentation.

In August 2003, the FASB issued EITF Issue 03-11, "Reporting Realized Gains and Losses on Derivative Instruments that are Subject to the FASB Statement No. 133 and Not "Held For Trading Purposes" as Defined in Issue No. 02-3." The reporting of realized gains and losses on physically settled derivative contracts based on the economic substance of the transaction. Our physically settled transactions are reported on a gross basis in the income statement in accordance with EITF Issue 03-11 guidance.

Potential Accounting Changes

At its September 9, 2003 meeting, the American Institute of Certified Public Accountants Accounting Standards Executive Committee approved a Statement of Position (SOP), "Accounting for Certain Costs and Activities Related to Property, Plant, and Equipment," subject to the Accounting Standards Executive Committee's positive clearance of certain revisions and the FASB clearance. The revised draft SOP sent to the FASB for clearance provides guidance on accounting for certain costs and activities relating to property, plant and equipment (PP&E). The following principles apply to the accounting for PP&E costs within the scope of the SOP.

PP&E consists of one or more components, which should be recorded at cost. A PP&E component should be depreciated over its expected useful life. The costs of a replacement component and the component replaced should not concurrently be recorded as assets. The SOP requires that an entity determine the level of component accounting for its PP&E, which should be set no higher than the functional unit level (i.e., a power plant, a building). A component is a tangible part or portion of PP&E that (1) an entity has elected to account for separately as an asset and (2) is expected to provide economic benefit for more than one year. In order for a replacement to be capitalized, the replaced item needs to have been previously separately accounted for as a component. If an entity replaces a part or portion of a separate component that previously has not been accounted for as a separate component, the replacement would be charged to expense. If, however, the entity determines that the replacement will be accounted for as a separate component in the future, this constitutes a change in accounting principle under APB Opinion 20. The method is to be applied consistently from period to period. Indirect, general and administrative costs and occupancy costs should be charged to expense as incurred. Additionally, under provisions of the SOP, major maintenance costs are to be expensed as incurred. Accordingly, we would be required to expense Wolf Creek refueling costs as incurred absent the regulatory treatment afforded these costs by the KCC. Removal costs should be considered costs associated with the removed component rather than any replacement component, and should be charged to expense. The SOP would be effective for fiscal years beginning after December 15, 2004.

OTHER INFORMATION

Sale of Utility Assets

In August 2003, we sold a portion of our transmission and distribution assets and rights to provide service to approximately 10,000 customers in an area of central Kansas. Total sales proceeds received were $33.3 million and we recorded a gain of $11.9 million, which is included as a reduction in operating and maintenance expenses on our consolidated income statement. We may enter into similar transactions in the future.

City of Wichita Franchise

On February 10, 2004, the Wichita city council approved a ten-year renewal of the franchise pursuant to which KGE provides retail electric service to the City of Wichita. The new ten-year franchise agreement is on terms that we believe to be reasonably similar to those previously in effect.

Network Integration Transmission Service

Effective January 1, 2002, we began taking Network Integration Transmission Service under the SPP's Open Access Transmission Tariff. This provides a way for us to participate in a broader market of generation resources. This tariff provides for a zonal rate structure, whereby transmission customers pay a pro rata share, in the form of a reservation charge, for the use of the facilities for each transmission owner that serves them. As a result, the SPP has functional control over our transmission system, although we still own our transmission assets and maintain responsibility for dispatching electricity, providing reliable transmission service, maintaining our transmission system and restoring our transmission system in the event there is a disruption to our system.

Currently, all revenues collected within an SPP zone for network integration transmission costs are allocated back to the transmission owner serving the zone. In 2003, our transmission costs for the Westar Energy zone were approximately $65.3 million. This amount, less $5.7 million that was retained by the SPP as administration cost, was returned to us as revenues. In 2002, our transmission costs were approximately $65.9 million with an administration cost of $5.8 million retained by the SPP. The SPP administration cost is recovered as part of retail rates and a charge to the applicable wholesale customers taking network integration transmission service. The revenues received are reflected in electric sales, and the related charges are expensed and included in reported operating expense.

Stranded Costs

Stranded costs for a utility business are commitments or investments in, and carrying costs on, PP&E, contractual obligations and other regulatory assets that exceed the amount that can be recovered in a competitive market. We currently apply accounting standards that recognize the economic effects of rate regulation and record regulatory assets and liabilities related to our electric utility operations. If we determine that we no longer meet the criteria of SFAS No. 71, we may have a material non-cash charge to earnings. Reasons for discontinuing SFAS No. 71 accounting treatment include increasing competition that may restrict our ability to charge prices needed to recover costs already incurred or a significant change by regulators from cost-based rate regulation to another form of rate regulation. We periodically review SFAS No. 71 criteria and believe our net regulatory assets are probable of future recovery. If we discontinue SFAS No. 71 accounting treatment based on competitive or other events, the value of our net regulatory assets and our utility plant investments, particularly Wolf Creek, may be significantly impacted.

Regulatory changes could adversely impact our ability to recover our investment in these assets. As of December 31, 2003, we have recorded regulatory assets currently subject to recovery in future rates of approximately $411.3 million. Of this amount, $207.8 million is a receivable for income tax benefits previously passed on to customers. The remainder of the regulatory assets are items that may give rise to stranded costs, including asset retirement obligations, loss on reacquired debt, refinancing costs on the LaCygne 2 lease, deferred employee benefit costs, deferred plant costs and coal contract settlement costs.

In a competitive environment, we may not be able to fully recover our entire investment in Wolf Creek. KGE presently owns 47% of Wolf Creek. We may also have stranded costs related to an inability to recover our environmental remediation costs and long-term fuel contract costs in a competitive environment. If we determine that we have stranded costs and we cannot recover our investment in these assets, our future net utility income will be lower than our historical net utility income has been unless we compensate for the loss of such income with other measures.

Asset Retirement Obligations

In January 2003, we adopted SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 requires recognition of legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development or normal operation of such assets. Concurrent with the recognition of the liability, the estimated cost of an asset retirement obligation is capitalized and depreciated over the remaining life of the asset. Any income effects are offset by regulatory accounting pursuant to SFAS No. 71.

Legal Liability - Wolf Creek

On January 1, 2003, we recognized the liability for our 47% share of the estimated cost to decommission Wolf Creek. SFAS No. 143 requires the recognition of the present value of the asset retirement obligation we incurred at the time Wolf Creek was placed into service in 1985. On January 1, 2003, we recorded an asset retirement obligation of $74.7 million. In addition, we increased our property and equipment balance, net of accumulated depreciation, by $10.7 million. We also established a regulatory asset for $64.0 million, which represents the accretion of the liability since 1985 and the increased depreciation expense associated with the increase in plant. The asset retirement obligation is included on our consolidated balance sheets in other long-term liabilities. Costs to retire Wolf Creek are currently being recovered through rates as provided by the KCC.

Non-legal Liability - Cost of Removal

We have recovered amounts in rates to provide for recovery of the probable costs of removing utility plant assets, but which do not represent legal retirement obligations. The amounts recovered were included as a component of depreciation expense in accordance with the FERC and KCC required ratemaking treatment. With the adoption of SFAS No. 143 we were required to quantify the net cost of removal included in accumulated depreciation. At December 31, 2002, we had $15.2 million included in accumulated depreciation that has been reclassified to other assets. At December 31, 2003, we had $6.6 million in removal costs that have been classified as a regulatory asset. The net amount related to non-legal retirement costs can fluctuate based on amounts related to removal costs recovered compared to removal costs incurred. Therefore, if in the future we recover removal costs in excess of amounts incurred we will recognize a regulatory liability for that amount. We do not anticipate that the adoption of SFAS No. 143 will have any impact on our electric rates.

See Note 18 of the Notes to Consolidated Financial Statements, “Asset Retirement Obligations,” for additional information regarding our asset retirement obligations.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Hedging Activity

We use financial and physical instruments to hedge a portion of our anticipated fossil fuel needs. At the time we enter into these transactions, we are unable to determine what the value will be when the agreements are actually settled.

In an effort to mitigate fuel commodity price market risk, we use hedging arrangements to reduce our exposure to increased coal, natural gas and oil prices. Our future exposure to changes in fossil fuel prices will be dependent on the market prices and the extent and effectiveness of any hedging arrangements into which we enter.

See Note 7 of the Notes to Consolidated Financial Statements, “Financial Instruments, Energy Trading and Risk Management — Derivative Instruments and Hedge Accounting — Hedging Activities,” for detailed information regarding hedging relationships and an interest rate swap we entered into during the third quarter of 2001.

Market Price Risks

Our hedging and trading activities involve risks, including commodity price risk, equity price risk, interest rate risk and credit risk. Commodity price risk is the risk that changes in commodity prices may impact the price at which we are able to buy and sell electricity and purchase fuels for our generating units. These commodities have experienced price volatility in the past and can be expected to do so in the future. This volatility may increase or decrease future earnings.

Equity price risk represents the risk we may be exposed to based on changes in the market value of our equity securities.

Interest rate risk represents the risk of loss associated with movements in market interest rates. In the future, we may continue to use swaps or other financial instruments to manage interest rate risk.

Credit risk represents the risk of loss resulting from non-performance by a counterparty of its contractual obligations. We have exposure to credit risk and counterparty default through our retail, energy marketing and trading activities. We maintain credit policies intended to reduce overall credit risk, and we actively monitor these policies to reflect changes and scope of operations. We employ additional credit risk control mechanisms when appropriate, such as letters of credit, parental guarantees and standardized master netting agreements from counterparties that allow for some of the offsetting of positive and negative exposures. Credit exposure is monitored and, when necessary, the activity with a specific counterparty is limited until credit enhancement is provided. Results actually achieved from hedging and trading activities could vary materially from intended results and could materially affect our consolidated financial results depending on the success of our credit risk management efforts.

Commodity Price Exposure

We engage in both financial and physical trading to manage our commodity price risk. We trade electricity, coal, natural gas and oil for the benefit of our regulated operations and our power marketing activities. We use a variety of financial instruments, including forward contracts, options and swaps and trade energy commodity contracts daily. We also use hedging techniques to manage overall fuel expenditures. We procure physical product under fixed price agreements and spot market transactions.

We are involved in trading activities primarily to reduce risk from market fluctuations and enhance system reliability. Net open positions exist, or are established, due to the origination of new transactions and our assessment of, and response to, changing market conditions. To the extent we have open positions, we are exposed to the risk that changing market prices could have a material, adverse impact on our consolidated financial position or results of operations.

We manage and measure the market price risk exposure of our trading portfolio using a variance/covariance value-at-risk (VaR) model. VaR is designed to measure the predicted worst-case loss at a specific confidence level over a specified period of time. In addition to VaR, we employ additional risk control processes such as stress testing, daily loss limits, and commodity position limits. We expect to use the same VaR model and control processes in 2004.

The use of the VaR method requires a number of key assumptions, including the selection of a confidence level for losses and the estimated holding period. We express VaR as a potential dollar loss based on a 95% confidence level using a one-day holding period. The calculation includes derivative commodity instruments used for both trading and risk management purposes. The VaR amounts for 2003 and 2002 were as follows:

	2003	2002
	(In Thousands)	
High	$1,393	$1,857
Low	144	150
Average	722	782

We have considered a number of risks and costs associated with the future contractual commitments included in our energy portfolio. These risks include credit risks associated with the financial condition of counterparties, product location (basis) differentials and other risks. Declines in the creditworthiness of our counterparties could have a material adverse impact on our overall exposure to credit risk. We maintain credit policies with regard to our counterparties that, in management's view, reduce our overall credit risk. There can be no assurance that the employment of VaR, or other risk management tools we employ, will eliminate the risk of loss.

We are also exposed to commodity price changes outside of trading activities. We use derivative contracts for non-trading purposes and a mix of various fuel types primarily to reduce exposure relative to the volatility of market and commodity prices. The wholesale power market is extremely volatile in price and supply. This volatility impacts our costs of power purchased and our participation in energy trades. If we were unable to generate an adequate supply of electricity for our retail customers, we would purchase power in the wholesale market to the extent it is available, subject to possible transmission constraints, and/or implement curtailment or interruption procedures as allowed for in our tariffs and terms and conditions of service. The increased expenses or loss of revenues associated with this could be material and adverse to our consolidated results of operations and financial condition.

From 2002 to 2003, we experienced an 8% increase in the average price per MWh of electricity purchased for utility operations. Purchased power market volatility could be greater than the average price increase indicates. Additionally, short-term, but extreme price volatility could potentially be of greater significance than the change in the average price would indicate, especially during adverse weather or market conditions. If we were to have a 10% increase in our purchased power price from 2003 to 2004, given the amount of power purchased for utility operations during 2003, we would have exposure of approximately $3.3 million of operating income. Due to the volatility of the power market, past prices cannot be used to predict future prices.

We use various fossil fuel types, including coal, natural gas and oil, to operate our system. A significant portion of our coal requirements are purchased under long-term contracts. During 2003, we experienced an approximate 30% increase, or $1.165 per MMBtu, in our average cost for natural gas purchased for utility operations. Due to this substantial increase in natural gas cost, we decreased our natural gas usage by 5.6 million MMBtu compared to the amount burned in 2002. Due to the volatility of natural gas prices, we have begun to increasingly utilize our ability to switch to lower cost fuel types as the market allows, primarily by using oil in our natural gas burning facilities. During 2003, we increased our oil usage by 4.8 million MMBtu compared to the amount burned in 2002. Although the average cost for oil purchased for utility operations increased $0.664 per MMBtu, or approximately 26%, compared to the average cost in 2002, it was $1.77 per MMBtu cheaper than the average cost of the natural gas we burned.

We use uranium to fuel our nuclear generating station and have on hand or under contract 84% of Wolf Creek's uranium needs and 100% of their uranium conversion needs for 2004. In addition, 94% of the uranium and 100% of the uranium conversion required for operation of Wolf Creek through October 2009 is under contract. The balance of the 2004 uranium requirements is expected to be purchased on the secondary (spot) market, which means we will be exposed to the price risk associated with these components.

Additional factors that affect our commodity price exposure are the quantity and availability of fuel used for generation and the quantity of electricity customers consume. Quantities of fossil fuel used for generation vary from year to year based on the availability, price and deliverability of a given fuel type as well as planned and scheduled outages at our facilities that use fossil fuels and the nuclear refueling schedule. Our customers' electricity usage could also vary from year to year based on the weather or other factors.

Interest Rate Exposure

We had approximately $427.4 million of variable rate debt and current maturities of fixed rate debt as of December 31, 2003. A 100 basis point change in each debt series' benchmark rate, used to set the rate for such series would impact net income on an annualized basis by approximately $3.7 million.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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SCHEDULES OMITTED

The following schedules are omitted because of the absence of the conditions under which they are required or the information is included on our consolidated financial statements and schedules presented:

I, III, IV, and V.

INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Shareholders of
Westar Energy, Inc.
Topeka, Kansas

We have audited the accompanying consolidated balance sheets of Westar Energy, Inc. and subsidiaries (the Company) as of December 31, 2003 and 2002, and the related consolidated statements of income (loss), comprehensive income (loss), shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2003. Our audits also included the financial statement schedule listed in the Index at Part IV, Item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. 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, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2003 and 2002, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

As discussed in Note 2, Note 5 and Note 18 to the financial statements, in 2003 the Company changed its method of accounting for asset retirement obligations and consolidation of variable interest entities; its method of accounting for goodwill and other intangible assets, and impairment of long-lived assets in 2002; and accounting for derivative contracts and hedging activities in 2001.

As discussed in Note 32 to the financial statements, the accompanying consolidated statements of cash flows have been restated.

DELOITTE & TOUCHE LLP
Kansas City, Missouri
March 5, 2004
(March 25, 2004 as to Note 32)

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WESTAR ENERGY, INC.

CONSOLIDATED BALANCE SHEETS
(Dollars in Thousands)

	As of December 31, 2003	As of December 31, 2002
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 79,559	$ 113,049
Restricted cash	17,925	156,391
Accounts receivable, net	80,972	49,202
Inventories and supplies	136,636	143,538
Energy trading contracts	35,385	44,175
Deferred tax assets	119,041	—
Prepaid expenses and other	43,176	38,336
Assets of discontinued operations	570,541	920,155
Total Current Assets	1,083,235	1,464,846
PROPERTY, PLANT AND EQUIPMENT, NET	3,909,500	3,938,944
OTHER ASSETS:		
Restricted cash	31,854	35,760
Investment in ONEOK	—	703,315
Regulatory assets	411,315	319,750
Nuclear decommissioning trust	80,075	63,522
Energy trading contracts	4,190	17,179
Other	214,336	197,009
Total Other Assets	741,770	1,336,535
TOTAL ASSETS	$5,734,505	$6,740,325
LIABILITIES AND SHAREHOLDERS’ EQUITY		
CURRENT LIABILITIES:		
Current maturities of long-term debt	$ 190,747	$ 290,294
Short-term debt	1,000	1,000
Accounts payable	94,700	84,168
Accrued liabilities	113,898	130,512
Accrued taxes	83,079	51,124
Energy trading contracts	28,000	43,370
Deferred tax liability	—	13,580
Other	20,486	63,476
Liabilities of discontinued operations	488,805	569,632
Total Current Liabilities	1,020,715	1,247,156
LONG-TERM LIABILITIES:		
Long-term debt, net	1,966,039	2,720,757
Long-term debt, affiliate	103,093	—
Shares subject to mandatory redemption	—	214,505
Deferred income taxes and investment tax credits	1,039,620	1,096,677
Deferred gain from sale-leaseback	150,810	162,638
Accrued employee benefits	101,892	85,484
Asset retirement obligation	80,695	—
Nuclear decommissioning	80,075	63,522
Energy trading contracts	1,111	8,341
Other	153,695	160,605
Total Long-Term Liabilities	3,677,030	4,512,529
COMMITMENTS AND CONTINGENCIES (Note 17)		
SHAREHOLDERS’ EQUITY:		
Cumulative preferred stock, par value $100 per share; authorized 600,000 shares; issued 248,576 shares; outstanding 214,363 shares	21,436	21,436
Common stock, par value $5 per share; authorized 150,000,000 shares; issued 72,840,217 shares	364,201	364,201
Paid-in capital	776,754	825,744
Unearned compensation	(15,879)	(14,742)
Loans to officers	(2)	(1,832)

Retained earnings (accumulated deficit)	(102,782)	(185,961)
Treasury stock, at cost, 203,575 and 1,333,264 shares, respectively	(2,391)	(18,704)
Accumulated other comprehensive loss, net	(4,577)	(9,502)
Total Shareholders’ Equity	1,036,760	980,640
TOTAL LIABILITIES AND SHAREHOLDERS’ EQUITY	$5,734,505	$6,740,325

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

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WESTAR ENERGY, INC.
CONSOLIDATED STATEMENTS OF INCOME (LOSS)
(Dollars in Thousands, Except Per Share Amounts)

	Year Ended December 31,		
	2003	2002	2001
SALES	$ 1,461,143	$ 1,423,151	$ 1,308,536
OPERATING EXPENSES:			
Fuel and purchased power	390,312	379,500	394,337
Operating and maintenance	371,372	379,220	343,344
Depreciation and amortization	167,236	171,807	185,519
Selling, general and administrative	160,825	218,345	174,301
Total Operating Expenses	1,089,745	1,148,872	1,097,501
INCOME FROM OPERATIONS	371,398	274,279	211,035
OTHER INCOME (EXPENSE):			
Investment earnings	36,732	77,092	52,634
Gain on sale of ONEOK stock	99,327	—	—
(Loss) gain on extinguishment of debt and settlement of putable/callable notes	(26,455)	(1,541)	1,395
Impairment of investments	(500)	(330)	(11,075)
Other income	5,180	1,349	10,173
Other expense	(16,643)	(38,380)	(15,514)
Total Other Income (Expense)	97,641	38,190	37,613
Interest expense	224,356	235,172	216,027
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES, CUMULATIVE EFFECTS OF ACCOUNTING CHANGES AND PREFERRED DIVIDENDS	244,683	77,297	32,621
Income tax expense (benefit)	81,768	(11,519)	(26,712)
INCOME FROM CONTINUING OPERATIONS BEFORE ACCOUNTING CHANGE AND PREFERRED DIVIDENDS	162,915	88,816	59,333
DISCONTINUED OPERATIONS:			
Discontinued operations, net of tax	(77,905)	(258,100)	(98,903)
Cumulative effect of accounting change, net of tax	—	(623,717)	—
Results of discontinued operations, net tax	(77,905)	(881,817)	(98,903)
Cumulative effects of accounting changes, net of tax of $12,347	—	—	18,694
NET INCOME (LOSS)	85,010	(793,001)	(20,876)
Preferred dividends, net of gain on reacquired preferred stock	968	399	895
EARNINGS (LOSS) AVAILABLE FOR COMMON STOCK	$ 84,042	$ (793,400)	$ (21,771)
BASIC AND DILUTED EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING (see Note 2):			
Basic earnings available from continuing operations before accounting changes	$ 2.24	$ 1.23	$ 0.83
Discontinued operations, net of tax	(1.08)	(3.60)	(1.40)
Accounting changes, including discontinued operations, net of tax	—	(8.69)	0.26
Basic earnings (loss) available	$ 1.16	$ (11.06)	$ (0.31)
Diluted earnings available from continuing operations before accounting changes	$ 2.21	$ 1.22	$ 0.82
Discontinued operations, net of tax	(1.06)	(3.57)	(1.38)
Accounting changes, including discontinued operations, net of tax	—	(8.63)	0.26
Diluted earnings (loss) available	$ 1.15	$ (10.98)	$ (0.30)
Average common shares outstanding	72,428,728	71,731,580	70,649,969
DIVIDENDS DECLARED PER COMMON SHARE	$ 0.76	$ 1.20	$ 1.20

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

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WESTAR ENERGY, INC.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(Dollars in Thousands)

	Year Ended December 31,					
	2003		2002		2001	
NET INCOME (LOSS)		$85,010		$(793,001)		$(20,876)
OTHER COMPREHENSIVE INCOME (LOSS), BEFORE TAX:						
Unrealized holding gain (loss) on marketable securities arising during the period	$ 99,412		$ —		$ (592)	
Reclassification adjustment for (gain) loss included in net income	(99,310)	102	—	—	3,336	2,744
Unrealized holding gain (loss) on cash flow hedges arising during the period	14,210		19,466		(31,735)	
Reclassification adjustment for (gain) loss included in net income	(6,483)	7,727	1,992	21,458	2,551	(29,184)
Minimum pension liability adjustment		284		(1,341)		(6,712)
Foreign currency translation adjustments		—		1,739		107
Other comprehensive income (loss), before tax		8,113		21,856		(33,045)
Income tax (expense) benefit related to items of other comprehensive income		(3,188)		(8,727)		13,615
Other comprehensive gain (loss), net of tax		4,925		13,129		(19,430)
COMPREHENSIVE INCOME (LOSS)		$89,935		$(779,872)		$(40,306)

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

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WESTAR ENERGY, INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS
(Dollars in Thousands)

	Year Ended December 31,		
	2003	2002	2001
		(As restated—see note 32)	
CASH FLOWS FROM (USED IN) OPERATING ACTIVITIES:			
Net income (loss)	$ 85,010	$ (793,001)	$ (20,876)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Discontinued operations, net of tax	77,905	881,817	98,903
Cumulative effect of accounting change	—	—	(18,694)
Depreciation and amortization	167,236	171,807	185,519
Amortization of deferred gain from sale-leaseback	(11,828)	(11,828)	(11,828)
Amortization of non-cash stock compensation	6,885	14,006	12,840
Net changes in energy trading assets and liabilities	(1,855)	20,229	10,683
Loss (gain) on extinguishment of debt and settlement of putable/callable notes	26,455	1,541	(1,395)
Net changes in fair value of call option	2,178	22,609	—
Equity in earnings from investments	—	(9,670)	(4,721)
Impairment on investments	500	330	11,075
(Gain) loss on sale of marketable securities	(99,327)	—	1,861
(Gain) loss on sale of utility plant and property	(11,912)	1,424	—
Accrued potential liability	1,205	22,928	—
Corporate-owned life insurance	(41,133)	(31,773)	(47,627)
Net deferred taxes	(94,838)	24,435	(12,200)
Changes in working capital items, net of acquisitions and dispositions:			
Restricted cash	(4,794)	(6,596)	(5,868)
Accounts receivable, net	(31,770)	(4,795)	31,944
Inventories and supplies	6,901	(8,955)	(48,369)
Prepaid expenses and other	61,048	(3,482)	(2,146)
Accounts payable	8,328	(21,026)	(28,541)
Accrued and other current liabilities	(76,565)	4,324	2,245
Accrued taxes	78,911	(22,640)	(23,875)
Changes in other, assets	1,170	1,146	(11,116)
Changes in other, liabilities	(23,304)	18,149	58
Cash flows from operating activities	126,406	270,979	117,872
CASH FLOWS FROM (USED IN) INVESTING ACTIVITIES:			
Additions to property, plant and equipment	(150,378)	(126,763)	(226,996)
Investment in corporate-owned life insurance	(19,599)	(19,399)	(19,852)
Proceeds from sale of utility plant and property	33,303	1,205	—
Proceeds from sale of marketable securities	801,841	—	2,829
Issuance of officer loans and interest, net of payments	438	(309)	(1,973)
Proceeds from other investments	801	18,296	63,198
Cash flows from (used in) investing activities	666,406	(126,970)	(182,794)
CASH FLOWS FROM (USED IN) FINANCING ACTIVITIES:			
Short-term debt, net	—	(221,300)	187,300
Proceeds of long-term debt	—	1,350,069	107
Retirements of long-term debt	(963,330)	(1,028,379)	(50,388)
Funds in trust for debt repayments	145,182	(135,000)	—
Purchase of call option investment	(65,785)	—	—
Net borrowings against cash surrender value of corporate-owned life insurance	58,399	52,630	57,759
Issuance of common stock, net	—	2,551	5,604
Cash dividends paid	(57,726)	(73,535)	(67,259)
Retirement of preferred stock	—	(1,547)	(545)
Acquisition of treasury stock	—	(19,544)	(866)
Reissuance of treasury stock	7,260	256	899
Cash flows (used in) from financing activities	(876,000)	(73,799)	132,611
Net cash from (used in) discontinued operations	49,698	(46,047)	13,329
Foreign currency translation	—	1,739	107
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(33,490)	25,902	81,125
CASH AND CASH EQUIVALENTS:			

Beginning of period	113,049	87,147	6,022
End of period	$ 79,559	$ 113,049	$ 87,147

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

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WESTAR ENERGY, INC.
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(Dollars in Thousands)

	Year Ended December 31,					
	2003		2002		2001	
	Shares	Amount	Shares	Amount	Shares	Amount
Cumulative preferred stock:						
Beginning balance	214,363	$ 21,436	239,364	$ 23,936	248,576	$ 24,858
Retirement of preferred stock	—	—	(25,001)	(2,500)	(9,212)	(922)
Ending balance	214,363	21,436	214,363	21,436	239,364	23,936
Common stock:						
Beginning balance	72,840,217	364,201	86,205,417	431,027	70,082,314	350,412
Issuance of common stock	—	—	6,936,289	34,681	16,123,103	80,615
Retirement of common stock	—	—	(20,301,489)	(101,507)	—	—
Ending balance	72,840,217	364,201	72,840,217	364,201	86,205,417	431,027
Paid-in capital:						
Beginning balance		825,744		1,196,765		868,166
Dividends on preferred stock		(968)		(996)		—
Retirement of preferred stock		1,696		(39)		(12)
Issuance of common stock		—		76,586		291,427
Dividends on common stock		(53,501)		(87,088)		—
Retirement of common stock		—		(349,397)		—
Issuance of treasury stock		671		2		—
Cancellation of restricted stock		—		—		14,570
Grant of restricted stock		7,631		7,872		15,791
Stock compensation		(4,519)		(17,961)		6,823
Ending balance		776,754		825,744		1,196,765
Unearned compensation:						
Beginning balance		(14,742)		(21,920)		(18,066)
Grant of restricted stock		(7,631)		(7,872)		(15,791)
Amortization of restricted stock		6,494		8,647		11,937
Forfeited restricted stock		—		6,403		—
Ending balance		(15,879)		(14,742)		(21,920)
Loans to officers:						
Beginning balance		(1,832)		(1,973)		—
Issuance of officer loans and interest, net of payments		438		(309)		(1,973)
Reclass loans of former officers to other assets		1,392		450		—
Ending balance		(2)		(1,832)		(1,973)
Retained earnings (accumulated deficit):						
Beginning balance		(185,961)		606,502		714,454
Net income (loss)		85,010		(793,001)		(20,876)
Dividends on preferred stock		—		—		(1,129)
Retirement of preferred stock, net		(1,696)		597		234
Dividends on common stock		—		—		(84,474)
Issuance of treasury stock		(135)		(59)		(1,707)
Ending balance		(102,782)		(185,961)		606,502
Treasury stock:						
Beginning balance	(1,333,264)	(18,704)	(15,097,987)	(364,901)	—	—
Issuance of common stock	—	—	(5,253,502)	(86,869)	(15,047,987)	(358,805)
Retirement of common stock	—	—	20,301,489	450,904	—	—
Acquisition of treasury stock	—	—	(1,434,100)	(19,508)	(50,000)	(866)
Issuance of treasury stock	1,129,689	16,313	150,836	1,670	520,300	9,340
Cancellation of restricted stock	—	—	—	—	(520,300)	(14,570)

Ending balance	(203,575)	(2,391)	(1,333,264)	(18,704)	(15,097,987)	(364,901)
Accumulated other comprehensive income (loss):						
Beginning balance		(9,502)		(22,631)		(3,201)
Unrealized gain on marketable securities		102		—		2,744
Unrealized gain (loss) on cash flow hedges		7,727		21,458		(29,184)
Minimum pension liability adjustment		284		(1,341)		(6,712)
Currency translation adjustment		—		1,739		107
Tax (expense) benefit		(3,188)		(8,727)		13,615
Ending balance		(4,577)		(9,502)		(22,631)
Total Shareholders’ Equity		$ 1,036,760		$ 980,640		$ 1,846,805

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

WESTAR ENERGY, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2003

1. DESCRIPTION OF BUSINESS

Westar Energy, Inc., a Kansas corporation incorporated in 1924, is the largest electric utility in Kansas. Unless the context otherwise indicates, all references in this Annual Report on Form 10-K to “the company,” “we,” “us,” “our” and similar words are to Westar Energy, Inc. and its consolidated subsidiaries. The term “Westar Energy” refers to Westar Energy, Inc. alone and not together with its consolidated subsidiaries. We provide electric generation, transmission and distribution services to approximately 644,000 customers in Kansas. Westar Energy provides these services in northeastern Kansas, including the Topeka, Lawrence, Manhattan, Salina and Hutchinson metropolitan areas. Kansas Gas and Electric Company (KGE), our wholly owned subsidiary provides these services in south-central and southeastern Kansas, including the Wichita metropolitan area. Both Westar Energy and KGE conduct business using the name Westar Energy. Our corporate headquarters is located at 818 South Kansas Avenue, Topeka, Kansas 66612.

KGE owns a 47% interest in the Wolf Creek Generating Station (Wolf Creek), a nuclear power plant located near Burlington, Kansas, and a 47% interest in Wolf Creek Nuclear Operating Corporation (WCNOC), the operating company for Wolf Creek.

Westar Industries, Inc. (Westar Industries), our wholly owned subsidiary, owned an 87% interest in Protection One, Inc. (Protection One), a publicly traded company that provides monitored security services, and our investment in Protection One Europe. Westar Industries now owns other non-material investments. We sold our interest in Protection One on February 17, 2004, and we sold our interest in Protection One Europe on June 30, 2003. In 2003, we classified our interests in monitored security businesses as discontinued operations. See Note 5, “Discontinued Operations,” for additional information about the classification of our monitored security businesses as discontinued operations.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation

We prepare our consolidated financial statements in accordance with generally accepted accounting principles (GAAP) for the United States of America. Our consolidated financial statements include all operating divisions and majority owned subsidiaries for which we maintain controlling interests. Common stock investments that are not majority owned are accounted for using the equity method when our investment allows us the ability to exert significant influence. Undivided interests in jointly-owned generation facilities are consolidated on a pro rata basis. All material intercompany accounts and transactions have been eliminated in consolidation.

Use of Management’s Estimates

When we prepare our consolidated financial statements, we are required to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities at the date of our consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. We evaluate our estimates on an on-going basis, including those related to bad debts, inventories, valuation of commodity contracts, depreciation, unbilled revenue, investments, valuation of our energy trading portfolio, intangible assets, income taxes, pension and other post-retirement and post-employment benefits, nuclear decommissioning of Wolf Creek, asset retirement obligations, net amount realizable from the disposition of our monitored security businesses, environmental issues, contingencies and litigation. Actual results may differ from those estimates under different assumptions or conditions.

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Regulatory Accounting

We currently apply accounting standards for our regulated utility operations that recognize the economic effects of rate regulation in accordance with Statement of Financial Accounting Standards (SFAS) No. 71, “Accounting for the Effects of Certain Types of Regulation,” and, accordingly, have recorded regulatory assets and liabilities when required by a regulatory order or based on regulatory precedent.

Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery in customer rates. Regulatory liabilities represent probable obligations to make refunds to customers for previous collections for costs that are not likely to be incurred in the future. We have recorded these regulatory assets and liabilities in accordance with SFAS No. 71. If we were required to terminate application of SFAS No. 71 for all of our regulated operations, we would have to record the amounts of all regulatory assets and liabilities on our consolidated statements of income (loss) at that time. Our earnings would be reduced by the net amount calculated from the table below, net of applicable income taxes. Regulatory assets and liabilities reflected on our consolidated balance sheets are as follows:

	As of December 31,	
	2003	2002
	(In Thousands)	
Recoverable income taxes	$ 207,812	$ 198,866
Debt reacquisition costs	25,155	28,169
Deferred employee benefit costs	18,424	25,555
Deferred plant costs	28,532	29,037
2002 ice storm costs	16,369	14,963
Asset retirement obligations	70,455	—
KCC depreciation	14,294	6,253
Wolf Creek outage	13,645	7,072
Other regulatory assets	16,629	9,835
Total regulatory assets	$ 411,315	$ 319,750
Total regulatory liabilities	$ 14,323	$ 8,445

- **Recoverable income taxes:** Recoverable income taxes represent amounts due from customers for accelerated tax benefits that have been previously flowed through to customers and are expected to be recovered in the future as the accelerated tax benefits reverse. This item will be recovered over the life of the utility plant.
- **Debt reacquisition costs:** Includes loss on reacquired debt and refinancing costs on the LaCygne 2 generating unit (LaCygne 2) lease. Debt reacquisition costs are amortized over the original term of the reacquired debt or, if refinanced, the term of the new debt.
- **Deferred employee benefit costs:** Deferred employee benefit costs represent post-retirement and post-employment expenses in excess of amounts paid that are to be recovered over a period of five years starting in July 2001 as authorized by the Kansas Corporation Commission (KCC).
- **Deferred plant costs:** Deferred plant costs under SFAS No. 90 related to the Wolf Creek nuclear generating facility will be recovered over the term of the plant’s operating license through 2025.
- **2002 ice storm costs:** Restoration costs associated with an ice storm that occurred in January 2002. We have received an accounting authority order from the KCC that allows us to accumulate and defer for potential future recovery all operating and carrying costs related to storm restoration.

- **Asset retirement obligations:** Asset retirement obligations represent amounts associated with our legal obligation to retire Wolf Creek. Retirement costs are currently being recovered through rates as provided by the KCC. We have placed amounts recovered through rates in a trust. The trust's funds will be used to pay for the costs to retire Wolf Creek. See Note 18, "Asset Retirement Obligations," for information regarding our Nuclear Decommissioning Trust Fund.
- **KCC depreciation:** Due to the change in our depreciation rates for ratemaking purposes for Wolf Creek and LaCygne 2, we record a regulatory asset for the amount that our depreciation expense exceeds our regulatory depreciation expense. See "—Depreciation" for additional information.
- **Wolf Creek outage:** Represents maintenance costs incurred in our most recent refueling outage. In accordance with regulatory treatment, this amount is amortized to expense ratably over the 18-month period after the outage.
- **Other regulatory assets:** This includes various regulatory assets that are relatively small in relation to the total regulatory assets balance. Other regulatory assets include property tax surcharge, coal contract settlement costs, rate case expense, and the removal component included in depreciation rates of the asset retirement obligation.
- **Other regulatory liabilities:** This includes various regulatory liabilities that are relatively small and includes provisions for rate refunds, property tax, emissions allowances, and savings from the sale of an office building.

A return is allowed on the 2002 ice storm costs, KCC depreciation and coal contract settlement costs (included in "Other regulatory assets" in the table above).

Cash and Cash Equivalents

We consider highly liquid investments with maturities of three months or less when purchased to be cash equivalents.

Restricted Cash

Restricted cash consists of cash irrevocably deposited in trust for a prepaid capacity and transmission agreement, letters of credit, surety bonds and escrow arrangements as required by certain letters of credit, and various other deposits.

Inventories and Supplies

Inventories and supplies for our utility business are stated at average cost.

Property, Plant and Equipment

Property, plant and equipment is stated at cost. For utility plant, cost includes contracted services, direct labor and materials, indirect charges for engineering and supervision, and an allowance for funds used during construction (AFUDC). AFUDC represents the cost of borrowed funds used to finance construction projects. The AFUDC rate was 5.27% in 2003, 5.95% in 2002 and 9.01% in 2001. The cost of additions to utility plant and replacement units of property is capitalized. AFUDC capitalized into construction in progress was $1.5 million in 2003, $2.2 million in 2002 and $8.7 million in 2001.

Maintenance costs and replacement of minor items of property are charged to expense as incurred. For utility plant, when a unit of depreciable property is retired, the original cost, less salvage value, is charged to accumulated depreciation.

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Depreciation

Utility plant is depreciated on the straight-line method at the lesser of rates set by the KCC or rates based on the estimated remaining useful lives of the assets, which are based on an average annual composite basis using group rates that approximated 2.5% during 2003, 2.66% during 2002 and 3.03% during 2001.

As a result of the 2001 KCC rate order, the KCC reduced our allowed depreciation rates for Wolf Creek and all of our coal generating stations resulting in an annual reduction in depreciation expense of approximately $30.0 million. Effective April 1, 2002, we adopted the new depreciation rates as prescribed in the KCC order.

As part of the 2001 KCC rate order, the KCC extended the estimated retirement date for Wolf Creek from 2025 to 2045, although our operating license for Wolf Creek expires in 2025. The KCC also extended the estimated retirement date for LaCygne 2 to 2032, although the term of our lease for LaCygne 2 expires in 2016. The effect of extending the retirement date was to reduce our amortization expense for leasehold improvements recovered in customer rates. For financial statement purposes, we recognize depreciation expense based on the current operating license and the initial lease term. We record a regulatory asset for the difference between the KCC allowed depreciation and financial statement depreciation. If our generating license for Wolf Creek is not renewed or the term of our lease for LaCygne 2 is not extended, we will need to seek relief from the KCC to recover the remaining cost of these assets.

Depreciable lives of property, plant and equipment are as follows:

	Years
Utility:	
Fossil fuel generating facilities	6 to 68
Nuclear fuel generating facility	38 to 45
Transmission facilities	28 to 67
Distribution facilities	19 to 57
Other	5 to 55

Nuclear Fuel

Our share of the cost of nuclear fuel used in the process of refinement, conversion, enrichment and fabrication is recorded as an asset in property, plant and equipment on our consolidated balance sheets at original cost and is amortized to cost of sales based on the quantity of heat consumed during the generation of electricity, as measured in millions of British Thermal Units (MMBtu). The accumulated amortization of nuclear fuel in the reactor was $16.6 million at December 31, 2003 and $25.2 million at December 31, 2002. Spent fuel charged to cost of sales was $17.0 million in 2003, $17.8 million in 2002 and $22.1 million in 2001.

Cash Surrender Value of Life Insurance

The following amounts related to corporate-owned life insurance policies (COLI) are recorded in other long-term assets on our consolidated balance sheets at December 31:

	2003	2002
	(In Millions)	
Cash surrender value of policies (a)	$ 884.8	$ 824.0
Borrowings against policies	(834.7)	(776.3)
COLI, net	$ 50.1	$ 47.7

(a) Cash surrender value of policies as presented represents the value of the policies as of the end of the respective policy years and not as of December 31, 2003 and 2002.

Income is recorded for increases in cash surrender value and net death proceeds. Interest incurred on amounts borrowed is offset against policy income. Income recognized from death proceeds is highly variable from period to period. Death benefits recognized as income approximated $1.8 million in 2003, $3.6 million in 2002 and $2.7 million in 2001.

Revenue Recognition - Energy Sales

Revenues from energy sales are recognized upon delivery to the customer and include an estimate for energy delivered but unbilled at the end of each year. Our estimate of revenue attributable to this unbilled portion is based on the total energy available for sale during the year measured against total billed sales and our estimates, based on historical data, of the portion of the unbilled revenues attributable to each of our different rate classes (retail or wholesale). If actual sales differ from the estimate, our revenues could be affected. At December 31, 2003, we had estimated unbilled revenue of $42.7 million.

Energy marketing activities are accounted for under the mark-to-market method of accounting. Under this method, changes in the portfolio value are recognized as gains or losses in the period of change. The net mark-to-market change is included in energy sales on our consolidated statements of income (loss). The resulting unrealized gains and losses are recorded as energy trading assets and liabilities on our consolidated balance sheets. We use quoted market prices to value our energy marketing and derivative contracts when such data are available. When market prices are not readily available or determinable, we use alternative approaches, such as model pricing. The quoted market prices used to value these transactions reflect our best estimate of fair values of our trading positions. Results actually achieved from these activities could vary materially from intended results and could affect our consolidated financial results. See Note 7, “Financial Instruments, Energy Trading and Risk Management,” for additional information regarding energy trading activities.

Income Taxes

Our consolidated financial statements use the liability method to reflect income taxes. Deferred tax assets and liabilities are recognized for temporary differences in amounts recorded for financial reporting purposes and their respective tax basis. We amortize deferred investment tax credits over the lives of the related properties.

Stock Based Compensation

For purposes of the pro forma disclosures required by SFAS No. 148, “Accounting for Stock Based Compensation - Transition and Disclosure,” the estimated fair value of stock options is amortized to expense over the relevant vesting period. While we began using restricted share units (RSUs) as our stock based compensation in 2001, we have approximately 226,700 stock options issued to employees in prior periods that were outstanding as of December 31, 2003. Information related to the pro forma impact on our consolidated earnings and earnings per share follows.

	2003	2002	2001
	(Dollars In Thousands, Except Per Share Amounts)		
Earnings (loss) available for common stock, as reported	$ 84,042	$ (793,400)	$ (21,771)
Add: Stock-based compensation included in earnings (loss) available for common stock, as reported, net of related tax effects	46	1	22
Deduct: Total stock option expense determined under fair value method for all awards, net of related tax effects	1,576	250	461
Earnings (loss) available for common stock, pro forma	$ 82,512	$ (793,649)	$ (22,210)
Weighted average shares used for dilution	73,354,011	72,258,696	71,718,132
Earnings (loss) per share:			
Basic - as reported	$ 1.16	$ (11.06)	$ (0.31)
Basic - pro forma	$ 1.14	$ (11.06)	$ (0.31)
Diluted - as reported	$ 1.15	$ (10.98)	$ (0.30)
Diluted - pro forma	$ 1.12	$ (10.98)	$ (0.31)

Accounting Changes

Accounting for Energy Trading Contracts

In May 2003, the Financial Accounting Standards Board (FASB) issued SFAS No. 149, “Amendment of Statement 133 on Derivative Instruments and Hedging Activities.” SFAS No. 149 amends the accounting for derivative instruments, including certain derivative instruments embedded in other contracts and for hedging activities, and clarifies which contracts qualify as “normal purchase/normal sale” contracts. SFAS No. 149 also amends certain other existing pronouncements and requires contracts with comparable characteristics to be accounted for similarly. In particular, SFAS No.149 clarifies when a contract with an initial net investment meets the characteristics of a derivative and when a derivative that contains a financing component will require special reporting in the statement of cash flows. SFAS No. 149 was effective for contracts entered into or modified after June 30, 2003. Adoption of SFAS No. 149 has not had a material effect on our consolidated results of operations, financial position or cash flows.

In October 2002, the FASB, through the Emerging Issues Task Force (EITF), reached consensus on EITF Issue No. 02-03, “Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities.” EITF Issue No. 02-03, in part, rescinded Issue No. 98-10, “Accounting for Contracts Involved in Energy Trading and Risk Management Activities.” As a result, all new contracts entered into after October 25, 2002 can no longer be marked-to-market and recorded in earnings unless they fall within the scope of SFAS No. 133. We were unaffected by this change in accounting principle and were not required to reclassify any of our contracts since our energy trading contracts qualify as derivative instruments under the guidance of SFAS No. 133. EITF Issue No. 02-03 also requires reporting energy trading contracts and derivatives in the income statement on a net basis effective January 1, 2003, whether the contracts are settled financially or physically. We began classifying our energy trading contracts on a net basis during the third quarter of 2002 and have reclassified all prior periods to reflect this presentation.

In August 2003, the FASB issued EITF Issue 03-11, “Reporting Realized Gains and Losses on Derivative Instruments that are Subject to the FASB Statement No. 133 and Not “Held For Trading Purposes” as Defined in Issue No. 02-3.” The reporting of realized gains and losses on physically settled derivative contracts is based on the economic substance of the transaction. Our physically settled transactions are reported on a gross basis in the income statement in accordance with EITF Issue 03-11 guidance.

On July 1, 2002, we began reporting mark-to-market gains and losses on energy trading contracts on a net basis, whether realized or unrealized, on our consolidated income statements. Prior to July 1, 2002, we reported gains on these contracts in sales and losses in cost of sales on our consolidated income statements. See Note 7, “Financial Instruments, Energy Trading and Risk Management,” for additional information on the effects of the accounting change.

Gains and Losses from Extinguishment of Debt

Effective July 1, 2002, we adopted SFAS No. 145, “Rescission of the FASB Statements No. 4, 44, and 64, Amendment of the FASB Statement No. 13, and Technical Corrections.” SFAS No. 145 limits the income statement classification of gains and losses from extinguishment of debt as extraordinary to those transactions meeting the criteria of APB Opinion No. 30, “Reporting the Results of Operations – Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions.” SFAS No. 145 prohibits extraordinary gain/loss treatment of gains and losses associated with extinguishments of debt that are a result of a company’s risk management strategy. Under SFAS No. 145, current gains and losses from the extinguishment of debt are reported as other income. Gains or losses in prior periods that were previously classified as extraordinary that do not meet the APB Opinion No. 30 criteria have been reclassified to other income. The adoption of this standard did not impact our net income or financial condition.

During the last three years, we repurchased our debt securities in the open market and recorded gains and losses on the extinguishment of these debt securities. We recognized a loss of $26.5 million in 2003, a loss of $1.5 million in 2002 and a gain of $1.4 million in 2001.

Accounting for Guarantees

In November 2002, the FASB issued Interpretation (FIN) No. 45, “Guarantor’s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others,” which provides guidance for accounting for guarantees. For any guarantee entered into after December 2002, a guarantor is required to recognize, at the inception of a guarantee, a liability for the fair value of the obligation undertaken in issuing the guarantee. Any future guarantee that we enter into will be accounted for as a liability.

In 1998, we issued a financial guarantee of an obligation of Onsite Energy Corporation under which our maximum liability was $1.3 million. This guarantee was released in the first quarter of 2003.

Consolidation of Variable Interest Entities

In January 2003, the FASB issued Financial Interpretation Number (FIN) 46, “Consolidation of Variable Interest Entities,” which was subsequently revised in December 2003 with the issuance of FIN 46R. The objective of this interpretation is to provide guidance on how to identify variable interest entities (VIE) and determine when the assets, liabilities, non-controlling interests and results of operations of a VIE need to be included in a company’s consolidated financial statements. We discuss the effects of FIN 46R in further detail in Note 6, “Accounts Receivable and Variable Interest Entities.”

Accounting for Mandatorily Redeemable Preferred Securities

In May 2003, the FASB issued SFAS No. 150, “Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity.” This statement establishes standards for the classification and measurement of certain financial instruments that have characteristics of both liabilities and equity. SFAS No. 150 requires that an issuer classify a financial instrument that is within the scope of this statement as a liability. This statement is effective for financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. We determined that the mandatorily redeemable preferred securities issued by Western Resources Capital I fell within the scope of SFAS No. 150. These trusts were included in the long-term debt line on our consolidated balance sheets as of September 30, 2003. Subsequently, FIN 46R was issued and it was determined that these securities are VIEs under FIN 46R and are to be deconsolidated. As of December 31, these trusts are reported as long-term debt, affiliate. See the discussion of “Consolidation of Variable Interest Entities” above, for additional information on this change.

Employers’ Disclosures about Pension and Other Post-retirement Benefits

On December 23, 2003, the FASB issued SFAS No. 132 (revised 2003), “Employers’ Disclosures about Pensions and Other Post-retirement Benefits — an amendment of the FASB Statements No. 87, 88 and 106” (SFAS No. 132R). SFAS No. 132R is effective for fiscal years ending after December 15, 2003. Interim disclosure requirements under SFAS No. 132R will be effective for interim periods beginning after December 15, 2003, and required disclosures related to estimated benefit payments will be effective for fiscal years ending after June 15, 2004.

SFAS No. 132R replaces the disclosure requirements in SFAS No. 87, “Employers’ Accounting for Pensions,” SFAS No. 88, “Employers’ Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits” and SFAS No. 106, “Employers’ Accounting for Post-retirement Benefits other than Pensions.” SFAS No. 132R addresses disclosures only and does not address measurement and recognition accounting for pension and post-retirement benefits, strategies, plan obligations, cash flows and net periodic benefit costs of defined benefit pension and post-retirement plans. Effective December 31, 2003, we adopted the disclosure requirements of SFAS No. 132R.

Dilutive Shares

Basic earnings per share applicable to common stock are based on the weighted average number of common shares outstanding and shares issuable in connection with vested RSUs during the period reported. Diluted earnings per share include the effect of potential issuances of common shares resulting from the assumed vesting of all outstanding RSUs and exercise of all outstanding stock options issued pursuant to the terms of our stock-based compensation plans. The dilutive effect of stock-based compensation and stock options is computed using the treasury stock method.

Diluted earnings per share amounts shown in the accompanying financial statements reflect the inclusion of non-vested restricted share awards and the effect of stock options outstanding. The following table reconciles the weighted average number of common shares outstanding used to compute basic and diluted earnings per share.

	Year Ended December 31,		
	2003	2002	2001
DENOMINATOR FOR BASIC AND DILUTED EARNINGS PER SHARE:			
Denominator for basic earnings per share - weighted average shares	72,428,728	71,731,580	70,649,969
Effect of dilutive securities:			
Employee stock options	305	—	2,832
Restricted share awards	924,978	527,116	1,065,331
Denominator for diluted earnings per share - weighted average shares	73,354,011	72,258,696	71,718,132
Potentially dilutive shares not included in the denominator since they are antidilutive	1,142,658	759,755	1,548,798

Supplemental Cash Flow Information

Cash paid for interest and income taxes for each of the three years ended December 31, are as follows:

	2003	2002	2001
		(In Thousands)	
CASH PAID FOR:			
Interest on financing activities, net of amount capitalized	$ 196,037	$ 235,199	$ 204,596
Income taxes	53,625	510	5,811
NON-CASH FINANCING TRANSACTIONS:			
Issuance of stock to subsidiary (See Note 22, "Common and Preferred Stock")	—	86,870	364,035
Issuance of stock under the Direct Stock Purchase Plan	5,841	16,544	18,278

Reclassifications

We have reclassified certain amounts in prior years to conform with classifications used in the current-year presentation.

Prior to 2003, cash flow activity related to our corporate owned life insurance (COLI) policies was presented net in the Operating Activities section of our consolidated statements of cash flows. In 2003, we reported cash out flows associated with the portion of the premium payment that increases the cash surrender value of the COLI policies as an investing activity. Accordingly, we have included $19.4 million and $19.9 million for years 2002 and 2001, respectively, as an Investing Activity in our statements of cash flows as it relates to the change in the cash surrender value. Also in 2003, the cash received from borrowings against the COLI policies is being reported as a financing activity. We have included $52.6 million and $57.8 million for years 2002 and 2001, respectively, as a Financing Activity on our consolidated statements of cash flows as it relates to these borrowings.

3. RATE MATTERS AND REGULATION

KCC Orders and Debt Reduction Plan

February 6, 2003 Debt Reduction Plan

On February 6, 2003, we filed a debt reduction plan (the Debt Reduction Plan) with the KCC in response to the KCC's order that would have required us to reduce debt to $1.67 billion by August 1, 2003. In the Debt Reduction Plan, we outlined our plans for paying down debt and simplifying our business. The Debt Reduction Plan detailed the following items that had already been accomplished by February 6, 2003, including, among other things, that:

- Consistent with the KCC's prior orders, we had terminated certain agreements and reversed certain intercompany transactions that might have prevented or impeded returning to being a stand-alone electric utility.

- We had sold a portion of our ONEOK, Inc. (ONEOK) stock and raised $300.0 million, the net proceeds of which we anticipated using to repurchase or provide for the repayment of our 6.25% senior unsecured notes that were putable and callable on August 15, 2003 (the putable/callable notes) and a portion of our 6.875% senior unsecured notes.
- Our board of directors had established a dividend policy that reduced our quarterly dividend on our common stock by 37% to a quarterly dividend rate of $0.19 per share.

In addition, the Debt Reduction Plan called for the following items to be accomplished:

- The sale of Protection One Europe.
- The sale of our interest in Protection One.
- The sale of all of our remaining ONEOK stock.
- The potential issuance of equity securities in 2004.

February 10, 2003 KCC Order

On February 10, 2003, the KCC issued an order granting limited reconsideration of its December 23, 2002 order. The KCC stayed the requirement of the December 23, 2002 order that we form a utility-only subsidiary. The KCC also stated that the Debt Reduction Plan appears to make a good-faith effort to address the concerns expressed in the KCC's prior orders and that the KCC needed additional time to review the Debt Reduction Plan prior to addressing other issues raised in our petition for reconsideration of the December 23, 2002 order.

March 11, 2003 KCC Order

On March 11, 2003, the KCC issued an order approving, with conditions, a partial Stipulation entered into by us, Protection One and certain parties in the KCC docket considering the Debt Reduction Plan. The order, among other things, (a) authorized us to make a payment to Protection One of up to $20.0 million for 2002 and prior tax years under the tax-sharing agreement with Protection One, (b) authorized Westar Industries to extend the maturity date of the credit facility it provides to Protection One to January 5, 2005, (c) reduced the amount that may be advanced to Protection One under the credit facility to $228.4 million, and (d) authorized us to pay approximately $3.6 million to Protection One as reimbursement for aviation services provided by a subsidiary of Protection One and for the repurchase of our common and preferred stock held by Protection One.

July 25, 2003 KCC Order

On July 21, 2003, we and Westar Industries entered into a Stipulation and Agreement (Stipulation) with the KCC staff and other intervenors in the docket considering the Debt Reduction Plan. The KCC issued an order approving the Stipulation on July 25, 2003. The principal terms of the Stipulation are as follows:

- We will fully implement the Debt Reduction Plan by December 31, 2004, unless prevented by events beyond our control, in which case the KCC may extend the deadline for implementation upon a proper showing by us.
- We will reduce our debt to a level consistent with investment grade bond ratings and have a capital structure comprised of at least 40% common equity by December 31, 2004. This commitment replaces the requirement imposed in the previous KCC order that we reduce utility debt to $1.67 billion by August 1, 2003.

- We will file a rate case, which may or may not include a request for a change in rates, by May 1, 2005, based on a test year consisting of the 12 months ending December 31, 2004.
- We will pay to our Kansas jurisdictional customers rebates of $10.5 million on May 1, 2005 and $10.0 million on January 1, 2006.
- We will also pay a rebate to customers for any amounts we may recover from David C. Wittig, our former president, chief executive officer and chairman, Douglas T. Lake, our former executive vice president, chief strategic officer and member of the board, for compensation totaling approximately $2.3 million paid to them that was included in our electric rates during calendar years 1998 through 2002, net of costs we incur to recover the funds. See Note 19, "Legal Proceedings," for more information about our efforts to recover compensation from Mr. Wittig and Mr. Lake.
- Westar Industries will transfer to Westar Energy all of its stock in ONEOK and all of its cash in excess of $2.0 million within 30 days of the date of the order.

February 13, 2004 KCC Order

On February 13, 2004, the KCC approved the sale of our interest in Protection One subject to the condition that we issue at least $97.2 million of common stock by December 31, 2004.

Current Status of the Debt Reduction Plan

In August 2003, we began ratably recording a regulatory liability for the rebates that will be paid to customers in 2005 and 2006. Accordingly, as of December 31, 2003, we have recorded a regulatory liability of $3.5 million for revenue to be refunded, which is included in other liabilities on our consolidated balance sheets.

Also in August 2003, Westar Industries transferred to Westar Energy all of its remaining stock in ONEOK and all of its cash in excess of $2.0 million. Westar Industries has continued to transfer cash in excess of $2.0 million in subsequent months. These transfers are intercompany transactions that do not result in any change to the amounts reported on our consolidated financial statements. In addition, in accordance with a KCC order, an intercompany receivable in the amount of $710.5 million from Westar Industries was reclassified as an investment in Westar Industries. This intercompany transaction is eliminated in consolidation.

In 2003, we reduced our debt by $965.7 million primarily through use of the proceeds from the sale of our ONEOK stock and through the retirement of $135.0 million of debt that was economically defeased in 2002.

4. SALE OF ONEOK STOCK INVESTMENT

We sold our ONEOK stock investment in multiple transactions in February, August and November 2003 for total proceeds of $801.8 million, net of transaction costs. We recorded a pre-tax gain of $99.3 million. We used the net proceeds for repayment of our outstanding debt.

5. DISCONTINUED OPERATIONS — SALE OF PROTECTION ONE AND PROTECTION ONE EUROPE

In 2003, we classified our monitored security businesses as discontinued operations. This is reflected in the accompanying consolidated financial statements. We also reclassified all historical periods to conform with this reclassification. These reclassifications were required by GAAP as a result of our board of directors' approval of the Debt Reduction Plan. The amounts associated with our discontinued operations are included in our "Other" segment. See Note 29, "Segments of Business," for further information relating to our "Other" segment.

We sold our interest in Protection One Europe on June 30, 2003. The sale resulted in a $58.7 million reduction in our consolidated debt level from the buyer's assumption of $48.2 million of Protection One Europe debt that was included in our consolidated financial statements and the use of $10.5 million of cash proceeds to pay down debt.

On December 23, 2003 we signed a definitive agreement to sell our interests in Protection One to subsidiaries of Quadrangle Capital Partners LP and Quadrangle Master Funding Ltd. (together, Quadrangle). The transaction did not include the sale of our Protection One 7 $^{3}/_{8}$% senior notes due August 15, 2005 in the face amount of $26.6 million.

On February 17, 2004, we closed the sale of the Protection One stock owned by Westar Industries to Quadrangle and assigned to Quadrangle the senior credit facility between Westar Industries and Protection One, which had an outstanding balance at December 31, 2003 and at closing of $215.5 million. At closing, we received proceeds of $122.2 million.

Protection One has been part of our consolidated tax group since 1997. During that time, we have reimbursed Protection One for current tax benefits attributable to Protection One used in our consolidated tax return under the terms of a tax sharing agreement. Following the sale of our Protection One common stock on February 17, 2004, Protection One is no longer a part of our consolidated tax group. We and Protection One did not formally terminate our tax sharing agreement and, based on discussions with Protection One and its counsel, there are several areas of potential dispute between us regarding our obligations under the terms of the tax sharing agreement. The most material of these potential disputes involve (i) the proper treatment under the tax sharing agreement of tax obligations or benefits arising out of the transaction in which we sold our interest in Protection One, including the impact of the cancellation of indebtedness income generated by the assignment of a credit agreement for less than the full amount outstanding under the credit agreement at closing on future payments, if any, to Protection One, (ii) whether any payments will be due to Protection One as a result of any tax benefits that may arise from a decision by us in the future to elect to treat the sale of our Protection One stock as a sale of assets under the Internal Revenue Code and (iii) whether payments due Protection One when we are subject to alternative minimum tax should be calculated at the alternative minimum tax rate of 20% or the normal statutory rate of 35%. Because of these potential disputes, we have provided for these matters in our consolidated financial statements. We nevertheless believe that we have strong positions with respect to each of these items and will aggressively pursue our positions. If we prevail, we may realize significant additional benefits, which may reduce future cash taxes and increase our reported net income.

Effective January 1, 2002, we adopted SFAS No. 142 and SFAS No. 144. SFAS No. 142 established new standards for accounting for goodwill. SFAS No. 142 continues to require the recognition of goodwill as an asset, but discontinued the amortization of goodwill. In addition, annual impairment tests must be performed using a fair-value based approach as opposed to an undiscounted cash flow approach required under prior standards. The completion of the impairment tests, based upon a valuation performed by an independent appraisal firm, as of January 1, 2002, indicated that the carrying values of goodwill at Protection One and Protection One Europe had been impaired and impairment charges were recorded as discussed below.

Another impairment test of Protection One's goodwill and customer accounts was completed as of July 1, 2002 (the date selected for Protection One's annual impairment test), with the independent appraisal firm providing the valuation of the estimated fair value of Protection One's reporting units, and no impairment was indicated. Protection One's stock price declined after regulatory orders were issued (see Note 3, of the Notes to Consolidated Financial Statements, "Rate Matters and Regulation"), including the KCC's December 23, 2002, order. As a result, Protection One retained the independent appraisal firm to perform an additional valuation of Protection One's reporting units so it could perform an impairment test as of December 31, 2002, which resulted in the additional impairment charge discussed below.

SFAS No. 144 established a new approach to determining whether our customer account asset is impaired. The approach no longer permitted the evaluation of the customer account asset for impairment based on the net undiscounted cash flow stream obtained over the remaining life of goodwill associated with the customer accounts being evaluated. Rather, the cash flow stream used under SFAS No. 144 is limited to future estimated undiscounted cash flows from assets in the asset group, which include customer accounts, the primary asset of the reporting unit, plus an estimated amount for the sale of the remaining assets within the asset group (including goodwill). If the undiscounted cash flow stream from the asset group is less than the combined book value of the asset group, then customer account asset carrying value must be written down to fair value, by recording an impairment.

The new rule substantially reduced the net undiscounted cash flows for customer account impairment evaluation purposes as compared to the previous accounting rules. Using these new guidelines, it was determined that there was an indication of impairment of the carrying value of the customer accounts and an impairment charge was recorded as discussed below.

To implement the new standards, an independent appraisal firm was engaged to help management estimate the fair values of Protection One's and Protection One Europe's goodwill and customer accounts. Based on this analysis, a charge was recorded in the first quarter of 2002 of approximately $749.3 million (net of tax benefit and minority interests), of which $555.4 million was related to goodwill and $193.9 million was related to customer accounts.

Protection One completed an additional impairment test of goodwill as of December 31, 2002 and we recorded an impairment charge of $79.7 million, net of tax benefit and minority interests, in the fourth quarter of 2002 to reflect the impairment of all remaining goodwill of Protection One's North America segment.

A $36 million impairment charge was recorded in the fourth quarter of 2002 to reflect the impairment of all remaining goodwill at Protection One Europe.

These charges for the year ended December 31, 2002, are detailed as follows:

	Impairment of Goodwill	Impairment of Customer Accounts	Total
		(In Thousands)	
Protection One	$ 719,885	$ 339,974	$ 1,059,859
Protection One Europe	116,154	—	116,154
Total pre-tax impairment	$ 836,039	$ 339,974	1,176,013
Income tax benefit			(203,958)
Minority interest			(107,172)
Net charge			$ 864,883

Before classifying our monitored services businesses as discontinued operations, we were unable to record a tax benefit for a significant portion of the goodwill impairment and amortization charges and losses of our monitored services businesses recorded in prior years. Upon classification as discontinued operations, GAAP requires the current recognition of any tax benefit that will be realized in the foreseeable future, net of any required valuation allowance. We estimate the tax benefits associated with the capital loss on the sale of Protection One and the assignment of the senior credit facility with Protection One to be approximately $327.7 million. Based on the sale of our ONEOK investment and current projections of taxable income, we estimate that it is likely that we will be able to realize approximately $93.8 million of these tax benefits. Therefore, we have recorded a $233.9 million valuation allowance for that portion of the tax benefit that we estimate may be unrealizable in the foreseeable future.

With discontinued operations accounting, we were required to estimate the net realizable proceeds from the sale of our monitored services businesses. We used actual sale proceeds to calculate the loss from discontinued operations related to Protection One Europe, which resulted in a write off of $13.5 million. When we initially classified Protection One as discontinued operations in the first quarter of 2003, our estimate of the net realizable proceeds from the sale of Protection One was based on an independent appraisal. At that time, we recorded a write down of $41.6 million on our Protection One investment. We updated our estimates in the third quarter of 2003 based on then existing bids from potential buyers and took an additional write down of $165.6 million. Upon signing the definitive agreement with Quadrangle on December 23, 2003, we reduced our estimated net realizable proceeds by an additional $38.5 million to reflect actual proceeds, and wrote off that amount in the fourth quarter of 2003.

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Results of discontinued operations are presented in the table below:

	Year Ended December 31,		
	2003	2002	2001
	(In Thousands, Except Per Share Amounts)		
Sales	$ 306,938	$ 351,499	$ 416,509
Costs and expenses	289,900	754,656	540,079
Earnings (loss) from discontinued operations before income taxes	17,038	(403,157)	(123,570)
Estimated loss on disposal	(258,979)	(1,853)	(16,924)
Income tax expense (benefit)	(164,036)	(146,910)	(41,591)
Results of discontinued operations before accounting change, net of tax	(77,905)	(258,100)	(98,903)
Cumulative effect of accounting change, net of tax of $72,335	—	(623,717)	—
Results of discontinued operations	$ (77,905)	$ (881,817)	$ (98,903)
Basic Loss Per Share:			
Results of discontinued operations, before accounting change	$ (1.08)	$ (3.60)	$ (1.40)
Cumulative effect of accounting change, net of tax	—	(8.69)	—
Results of discontinued operations, net of tax	$ (1.08)	$ (12.29)	$ (1.40)
Diluted Loss Per Share:			
Results of discontinued operations, before accounting change	$ (1.06)	$ (3.57)	$ (1.38)
Cumulative effect of accounting change, net of tax	—	(8.63)	—
Results of discontinued operations, net of tax	$ (1.06)	$ (12.20)	$ (1.38)

The major classes of assets and liabilities of the monitored services businesses are as follows :

	December 31,	
	2003	2002
	(In Thousands)	
Assets:		
Current	$ 80,850	$ 76,029
Property and equipment	60,656	17,461
Customer accounts, net	268,533	402,646
Goodwill, net	41,847	41,847
Other	118,655	382,172
Total assets	$570,541	$920,155
Liabilities:		
Current	$ 82,024	$129,512
Long-term debt	305,234	337,567
Other long-term liabilities	101,547	102,553
Total liabilities	$488,805	$569,632

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6. ACCOUNTS RECEIVABLE AND VARIABLE INTEREST ENTITIES

Our accounts receivable on our consolidated balance sheets are comprised as follows:

	As of December 31,	
	2003	2002
	(In Thousands)	
Gross accounts receivable	$123,674	$ 120,974
Allowance for uncollectable accounts	(5,415)	(5,978)
Unbilled energy receivables	42,713	44,206
Accounts receivable sale program	(80,000)	(110,000)
Accounts receivable, net	$ 80,972	$ 49,202

Accounts Receivable Sales Program

On July 28, 2000, Westar Energy and KGE entered into an agreement with WR Receivables Corporation, a wholly owned, bankruptcy-remote special purpose entity (SPE) to sell all of their accounts receivable arising from the sale of electricity to the SPE. These transfers are accounted for as sales in accordance with SFAS No. 140, “Accounting for Transfers and Servicing of Financial Assets and Extinguishment of Liabilities.” The SPE may sell up to $125 million of an undivided interest in the accounts receivable to a third party conduit under various terms and conditions. The percentage ownership interest in receivables held by the third party conduit will increase or decrease over time, depending on the characteristics of the SPE’s receivables, including delinquency rates and debtor concentrations. The agreement with the third party conduit is renewable annually upon agreement by all parties. On July 23, 2003, the term of the agreement was extended through July 21, 2004.

The SPE receivable from WR Receivables Corporation represents our retained interests in the transferred receivables. It is included in accounts receivable, net, on our consolidated balance sheets. The interests that we hold are included in the table below:

	As of December 31,	
	2003	2002
	(In Thousands)	
Undivided Interest - Retained, net	$ 71,213	$ 35,803
Undivided Interest – Third party conduit, net	9,186	12,403
SPE receivable, net	$ 80,399	$ 48,206

The outstanding balance of SPE receivables is net of $80.0 million at December 31, 2003 and $110.0 million at December 31, 2002 in undivided ownership interests sold by the SPE to the third party conduit.

The following table provides proceeds and repayments between the SPE and the third party conduit. These amounts are provided for cash flow purposes and may not be reflective of accrual accounting. These items are recorded on the statements of cash flows in the “Accounts receivable, net” line of cash flows from operating activities.

	Year Ended December 31,		
	2003	2002	2001
		(In Thousands)	
Proceeds from the sale of an undivided interest from the third party conduit	$ —	$ 30,000	$ 25,000
Repayments to the conduit for net collection of its receivable	(30,000)	(20,000)	(40,000)
	$(30,000)	$ 10,000	$(15,000)

A termination event will be triggered under the terms of the agreement with the third party conduit if Westar Energy’s corporate credit rating ceases to be at least BB- by Standard & Poor’s Ratings Group (S&P) or if its issuer rating ceases to be at least Ba3 by Moody's Investors Service. If a termination event occurs, the third party conduit may give notice to us and declare a termination date. If a termination date occurs under the facility, the SPE will discontinue purchasing receivables from Westar Energy and KGE. Any collections of receivables received by the SPE after the termination date will be allocated based on the ownership interest of the SPE and the third party conduit.

Consolidation of Variable Interest Entities

In January 2003, the FASB issued Financial Interpretation Number (FIN) 46, "Consolidation of Variable Interest Entities," which was subsequently revised in December 2003 with the issuance of FIN 46R. The objective of this interpretation is to provide guidance on how to identify VIEs and determine when the assets, liabilities, non-controlling interests and results of operations of a VIE need to be included in a company's consolidated financial statements. A company that holds variable interests in an entity will need to consolidate the entity if the company's interest in the VIE is such that the company will absorb a majority of the VIE's expected losses and/or receive a majority of the entity's expected residual returns, if they occur. FIN 46R also requires additional disclosures by primary beneficiaries and other significant variable interest holders.

On December 14, 1995, Western Resources Capital I, a wholly owned trust, issued $100.0 million of 7 7/8% Cumulative Quarterly Income Preferred Securities, Series A. On July 31, 1996, Western Resources Capital II, a wholly owned trust, issued $120.0 million of 8 1/2% Cumulative Quarterly Income Preferred Securities, Series B. On September 22, 2003, we redeemed our entire issuance of Western Resources Capital II 8 1/2% Cumulative Quarterly Income Preferred Securities, Series B, at par.

Provisions of FIN 46R require the deconsolidation of the Western Resources Capital I trust, which resulted in the amounts previously classified as shares subject to mandatory redemption being reclassified as long-term debt, affiliate on the balance sheet and the recording of an investment representing our equity investment in the trust as of December 31, 2003.

7. FINANCIAL INSTRUMENTS, ENERGY TRADING AND RISK MANAGEMENT

Values of Financial Instruments

The carrying values and estimated fair values of our financial instruments are as follows:

	Carrying Value		Fair Value	
	As of December 31,			
	2003	2002	2003	2002
	(In Thousands)			
Fixed-rate debt, net of current maturities (a)	$ 1,815,558	$ 2,210,779	$ 1,946,291	$ 2,123,625

(a) Fair value is estimated based on quoted market prices for the same or similar issues or on the current rates offered for instruments of the same remaining maturities and redemption provisions.

The recorded amounts of accounts receivable and other current financial instruments approximate fair value. Cash and cash equivalents, short-term borrowings and variable-rate debt are carried at cost, which approximates fair value and are not included in the table above.

The fair value estimates are based on information available at December 31, 2003 and 2002. These fair value estimates have not been comprehensively revalued since that date and current estimates of fair value may differ significantly from the amounts above.

Derivative Instruments and Hedge Accounting

We are exposed to market risks from changes in commodity prices and interest rates that could affect our consolidated results of operations and financial condition. We manage our exposure to these market risks through our regular operating and financing activities and, when deemed appropriate, hedge a portion of these risks through the use of derivative financial instruments. We use the term hedge to mean a strategy designed to manage risks of volatility in prices or rate movements on some assets, liabilities or anticipated transactions by creating a relationship in which gains or losses on derivative instruments are expected to counterbalance the losses or gains on the assets, liabilities or anticipated transactions exposed to such market risks. We use derivative instruments as risk management tools consistent with our business plans and prudent business practices and for energy trading purposes.

We use derivative financial and physical instruments primarily to manage risk as it relates to changes in the prices of commodities including natural gas, oil, coal and electricity and changes in interest rates. We also use derivative instruments for trading purposes in order to take advantage of favorable price movements and market timing activities in the wholesale power and fossil fuel markets. Derivative instruments used to manage commodity price risk inherent in fossil fuel and electricity purchases and sales are classified as energy trading contracts on our consolidated balance sheets. Energy trading contracts representing unrealized gain positions are reported as assets; energy trading contracts representing unrealized loss positions are reported as liabilities.

Energy Trading Activities

We engage in both financial and physical trading to manage our commodity price risk. We trade electricity, coal, natural gas and oil. We use a variety of financial instruments, including forward contracts, options and swaps and trade energy commodity contracts daily. We also use hedging techniques to manage overall fuel expenditures. We procure physical product under fixed price agreements and spot market transactions.

Within the trading portfolio, we take certain positions to hedge a portion of physical sale or purchase contracts and we take certain positions to take advantage of market trends and conditions. Changes in value are reflected on our consolidated statements of income (loss). We believe financial instruments help us manage our contractual commitments, reduce our exposure to changes in cash market prices and take advantage of selected market opportunities. We refer to these transactions as energy trading activities.

We are involved in trading activities primarily to reduce risk from market fluctuations and enhance system reliability. Net open positions exist, or are established, due to the origination of new transactions and our assessment of, and response to, changing market conditions. To the extent we have open positions, we are exposed to the risk that changing market prices could have a material, adverse impact on our consolidated financial position or results of operations.

We have considered a number of risks and costs associated with the future contractual commitments included in our energy portfolio. These risks include credit risks associated with the financial condition of counterparties, product location (basis) differentials and other risks. Declines in the creditworthiness of our counterparties could have a material adverse impact on our overall exposure to credit risk. We maintain credit policies with regard to our counterparties that, in management’s view, reduce our overall credit risk.

We are also exposed to commodity price changes outside of trading activities. We use derivative contracts for non-trading purposes and a mix of various fuel types primarily to reduce exposure relative to the volatility of market and commodity prices. The wholesale power market is extremely volatile in price and supply. This volatility impacts our costs of power purchased and our participation in energy trades. If we were unable to generate an adequate supply of electricity for our retail customers, we would purchase power in the wholesale market to the extent it is available, subject to possible transmission constraints, and/or implement curtailment or interruption procedures as allowed for in our tariffs and terms and conditions of service. The increased expenses or loss of revenues associated with this could be material and adverse to our consolidated results of operations and financial condition.

We use various fossil fuel types, including coal, natural gas and oil, to operate our system. A significant portion of our coal requirements are purchased under long-term contracts. Due to the volatility of natural gas prices, we have begun to increasingly utilize our ability to switch to lower cost fuel types as the market allows, primarily by using oil in our natural gas burning facilities.

Additional factors that affect our commodity price exposure are the quantity and availability of fuel used for generation and the quantity of electricity customers consume. Quantities of fossil fuel used for generation vary from year to year based on the availability, price and deliverability of a given fuel type as well as planned and scheduled outages at our facilities that use fossil fuels and the nuclear refueling schedule. Our customers' electricity usage could also vary from year to year based on weather or other factors.

Although we generally attempt to balance our physical and financial contracts in terms of quantities and contract performance, net open positions typically exist. We will at times create a net open position or allow a net open position to continue when we believe that future price movements will increase the portfolio's value. To the extent we have an open position, we are exposed to changing market prices that could have a material adverse impact on our consolidated financial position or results of operations.

The prices we use to value price risk management activities reflect our estimate of fair values considering various factors, including closing exchange and over-the-counter quotations, time value of money and price volatility factors underlying the commitments. We adjust prices to reflect the potential impact of liquidating our position in an orderly manner over a reasonable period of time under present market conditions. We consider a number of risks and costs associated with the future contractual commitments included in our energy portfolio, including credit risks associated with the financial condition of counterparties and the time value of money. We continuously monitor the portfolio and value it daily based on present market conditions.

Future changes in our creditworthiness and the creditworthiness of our counterparties may change the value of our portfolio. We adjust the value of contracts and set dollar limits with counterparties based on our assessment of their credit quality.

We use derivative financial instruments to reduce our exposure to certain fluctuations in some commodity prices, interest rates, and other market risks. With respect to some financial instruments we enter into, we formally designate and document the instrument as a hedge of a specific underlying exposure, as well as the risk management objectives and strategies for undertaking the hedge transaction. Because of the high degree of correlation between the hedging instrument and the underlying exposure being hedged, fluctuations in the value of the derivative instruments are generally offset by changes in the value or cash flows of the underlying exposures being hedged.

The fair values of derivative contracts used to hedge or modify our risks fluctuate over time. These fair value amounts should not be viewed in isolation, but rather in relation to the fair values or cash flows of the underlying hedged transactions and the overall reduction in our risk relating to adverse fluctuations in interest rates, commodity prices and other market factors. In addition, the net income effect resulting from our derivative instruments is recorded in the same line item within our consolidated statements of income (loss) as the underlying exposure being hedged. We also formally assess, both at the inception and at least quarterly thereafter, whether the financial instruments that are used in hedging transactions are effective at offsetting changes in either the fair value or cash flows of the related underlying exposures.

Hedging Activities

During the third quarter of 2001, we entered into hedging relationships to manage commodity price risk associated with future natural gas purchases. Initially, we entered into futures and swap contracts with terms extending through July 2004 to hedge price risk for a portion of our anticipated natural gas fuel requirements for our generation facilities. We designated these hedging relationships as cash flow hedges.

In 2002, due to the increased availability of our coal units and because we began burning more oil as use of oil became more economically favorable than natural gas, we did not burn our forecasted amount of natural gas. In September 2002, we determined that we had over-hedged approximately 12,000,000 MMBtu for the remaining period of the hedge. As a result of the discontinuance of this portion of the cash flow hedge, we recognized a gain of $4.0 million. In December 2003, we determined we could no longer meet the criteria to use hedge accounting for the 2004 forecasted gas purchases. As a result, we recognized in income a gain of $3.7 million, of which $2.8 million had previously been recognized in other comprehensive income.

Effective October 4, 2001, we entered into a $500.0 million interest rate swap agreement with a term of two years. At that time, the effect of the swap agreement was to fix the annual interest rate on the term loan at 6.18%. In June 2002, we refinanced the term loan associated with this swap, which increased the effective rate of the swap to 6.43%.

In the second quarter of 2003, we purchased a call option at a cost of $65.8 million, which locked in a settlement cost associated with a call option entered into in 1998 related to our 6.25% putable/callable notes. The portion of the call option that related to the portion of debt outstanding was treated as a cash flow hedge for accounting purposes. See Note 14, "Call Option," for further information relating to the call option.

8. PROPERTY, PLANT AND EQUIPMENT

The following is a summary of property, plant and equipment at December 31:

	2003	2002
	(In Thousands)	
Electric plant in service	$ 6,467,797	$ 6,414,231
Accumulated depreciation	(2,647,214)	(2,537,340)
	3,820,583	3,876,891
Construction work in progress	59,570	40,071
Nuclear fuel, net	29,198	21,694
Net utility plant	3,909,351	3,938,656
Non-utility plant in service	149	288
Net property, plant and equipment	$ 3,909,500	$ 3,938,944

Depreciation expense on property, plant and equipment for the years ended December 31, 2003, 2002 and 2001 was as follows:

	2003	2002	2001
		(In Thousands)	
Utility	$ 167,226	$ 171,749	$ 185,156
Non-utility	10	58	363
Total depreciation expense	$ 167,236	$ 171,807	$ 185,519

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9. JOINT OWNERSHIP OF UTILITY PLANTS

		Our Ownership at December 31, 2003					
		In-Service Dates		Investment	Accumulated Depreciation	Net MW	Ownership Percent
		(Dollars in Thousands)					
LaCygne 1	(a)	June	1973	$ 194,471	$ 120,008	344.0	50
Jeffrey 1	(b)	July	1978	314,032	156,527	618.0	84
Jeffrey 2	(b)	May	1980	310,291	137,996	617.0	84
Jeffrey 3	(b)	May	1983	415,636	196,608	624.0	84
Jeffrey wind 1	(b)	May	1999	875	186	0.6	84
Jeffrey wind 2	(b)	May	1999	874	186	0.6	84
Wolf Creek	(c)	Sept.	1985	1,407,696	576,649	548.0	47
State Line	(d)	June	2001	107,846	10,754	202.0	40

(a) Jointly owned with Kansas City Power & Light Company (KCPL)
(b) Jointly owned with Aquila, Inc.
(c) Jointly owned with KCPL and Kansas Electric Power Cooperative, Inc.
(d) Jointly owned with The Empire District Electric Company

Amounts and capacity presented above represent our share. Our share of operating expenses of the plants in service above, as well as such expenses for a 50% undivided interest in LaCygne 2 (representing 337 megawatt (MW) capacity) sold and leased back to KGE in 1987, are included in operating expenses on our consolidated statements of income (loss). Our share of other transactions associated with the plants is included in the appropriate classification in our consolidated financial statements.

10. INVESTMENTS ACCOUNTED FOR BY THE EQUITY METHOD

A portion of our investment in ONEOK was previously accounted for by the equity method. We sold our ONEOK stock investment in multiple transactions in February, August and November 2003.

	Ownership at December 31, 2003	Investment at December 31,		Equity Earnings, Year Ended December 31,		
		2003	2002	2003	2002	2001
		(In Thousands)				
ONEOK	—	$—	$ 703,315	$—	$9,670	$4,721

During 2001, we disposed of 98% of our portfolio of affordable housing tax credit limited partnerships. The net impact of our total investment in these partnerships on our earnings, including equity in earnings, loss on disposal and generated tax credits was a net benefit of $5.3 million.

11. SHORT-TERM DEBT

Certain banks provide us a revolving credit facility on a committed basis totaling $150.0 million. The facility is secured by KGE's first mortgage bonds and matures on June 6, 2005, provided that if we have not refinanced or provided for the payment of our 6.875% senior unsecured notes due August 1, 2004, at least 60 days prior to the due date, the maturity date is 60 days prior to the August 1, 2004 maturity date. As of December 31, 2003, borrowings on the revolving credit facility were $1.0 million, leaving $149.0 million remaining capacity under this facility. See Note 12, "Long-term Debt," for a discussion of covenants applicable to our credit facilities.

Information regarding our short-term borrowings is as follows:

	As of December 31,	
	2003	2002
	(Dollars in Thousands)	
Borrowings outstanding at year end:		
Credit agreement and an other financing arrangement	$1,000	$ 1,000
Weighted average interest rate on debt outstanding at year-end, excluding fees	6.08%	6.34%
Weighted average short-term debt outstanding during the year	$1,009	$168,078
Weighted daily average interest rates during the year, excluding fees	6.12%	3.67%

Our interest expense on short-term debt and other was $1.2 million in 2003, $7.4 million in 2002 and $8.1 million in 2001.

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12. LONG-TERM DEBT

Outstanding Debt

Long-term debt outstanding at December 31 is as follows:

	2003	2002
	(In Thousands)	
Westar Energy		
First mortgage bond series:		
7 7/8% due 2007	$ 365,000	$ 365,000
8 1/2% due 2022	125,000	125,000
7.65% due 2023	100,000	100,000
	590,000	590,000
Pollution control bond series:		
Variable due 2032, 1.10% at December 31, 2003	45,000	45,000
Variable due 2032, 1.04% at December 31, 2003	30,500	30,500
6% due 2033	58,340	58,340
	133,840	133,840
6 7/8% unsecured senior notes due 2004	184,456	278,310
9 3/4% unsecured senior notes due 2007	387,000	387,000
7 1/8% unsecured senior notes due 2009	145,078	145,078
6.80% unsecured senior notes due 2018	26,993	27,396
6.25% unsecured senior notes due 2018, putable/callable 2003	—	146,390
Senior secured term loan due 2005, variable rate of 4.22% at December 31, 2003	114,143	584,000
Capital leases	22,593	27,356
Other long-term agreements	4,179	4,352
	884,442	1,599,882
KGE		
First mortgage bond series:		
7.60% due 2003 (a)	—	135,000
6 1/2% due 2005	65,000	65,000
6.20% due 2006	100,000	100,000
	165,000	300,000
Pollution control bond series:		
5.10% due 2023	13,488	13,493
Variable due 2027, 1.15% at December 31, 2003	21,940	21,940
7.0% due 2031	327,500	327,500
Variable due 2032, 1.17% at December 31, 2003	14,500	14,500
Variable due 2032, 1.15% at December 31, 2003	10,000	10,000
	387,428	387,433
Unamortized debt premium (b)	—	4,822
Unamortized debt discount (b)	(3,924)	(4,926)
Long-term debt due within one year (c)	(190,747)	(290,294)
Long-term debt, net	$ 1,966,039	$ 2,720,757
Long-term debt, affiliate (d)	$ 103,093	$ —
7 7/8% cumulative quarterly income preferred securities, Series A, due 2025 (d)	$ —	$ 98,835
8 1/2% cumulative quarterly income preferred securities, Series B, due 2036 (e)	—	115,670
Shares subject to mandatory redemption	$ —	$ 214,505

(a) Funds were irrevocably deposited with the bond trustee in 2002 to provide for repayment of this obligation in 2003.
(b) Debt premiums and discounts are being amortized over the remaining lives of each issue.
(c) Includes capital leases, which are discussed in further detail in Note 25.
(d) Reclassified due to adoption of FIN 46R. See Note 6, “Accounts Receivable and Variable Interest Entities,” for further detail.
(e) On September 22, 2003, we redeemed our entire issue at par.

The amount of Westar Energy’s first mortgage bonds authorized by its Mortgage and Deed of Trust, dated July 1, 1939, as supplemented, is unlimited subject to certain limitations as described below. The amount of KGE’s first mortgage bonds authorized by the KGE Mortgage and Deed of Trust, dated April 1, 1940, as supplemented, is limited to a maximum of $2 billion, unless amended. First mortgage bonds are secured by utility assets. Amounts of additional bonds that may be issued are subject to property, earnings and certain restrictive provisions of each mortgage. As of December 31, 2003, $361.3 million principal amount of additional first mortgage bonds could be issued under the most restrictive provisions in Westar Energy’s mortgage, except in connection with refundings. As of December 31, 2003, approximately $889.0 million principal amount of additional KGE first mortgage bonds could be issued under the most restrictive provisions in the mortgage.

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Debt Covenants

Some of our debt instruments contain restrictions that require us to maintain various coverage and leverage ratios as defined in the agreements. Our calculations of these ratios are performed in accordance with our debt agreements and are used solely to determine compliance with our various debt covenants. We were in compliance with these covenants as of December 31, 2003.

On November 6, 2003, we entered into a Waiver and Amendment with the lenders under our revolving credit facility, which waived any default arising as a result of the redemption of the Western Resources mandatorily redeemable preferred securities, Series B, and amended the revolving credit facility to permit us to redeem the Western Resources mandatorily redeemable preferred securities, Series A, in the future.

Maturities

Maturities of long-term debt as of December 31, 2003 are as follows:

Year	Principal Amount (In Thousands)
2004	$ 190,747
2005	183,395
2006	103,879
2007	755,489
2008	2,732
Thereafter	1,023,637
	$ 2,259,879

Our interest expense on long-term debt was $223.2 million in 2003, $227.8 million in 2002 and $207.9 million in 2001.

Other Mandatorily Redeemable Securities

On December 14, 1995, Western Resources Capital I, a wholly owned trust, issued $100.0 million of 7 7/8% Cumulative Quarterly Income Preferred Securities, Series A. The securities are redeemable at the option of Western Resources Capital I on or after December 11, 2000, at $25 per security plus accrued interest and unpaid dividends. Holders of the securities are entitled to receive distributions at an annual rate of 7 7/8% of the liquidation value of $25. Distributions are payable quarterly and are tax deductible by us. These distributions are recorded as interest expense. The sole asset of the trust is $103.1 million principal amount of Westar Energy 7 7/8% Deferrable Interest Subordinated Debentures, Series A due December 11, 2025.

On July 31, 1996, Western Resources Capital II, a wholly owned trust, issued $120.0 million of 8 1/2% Cumulative Quarterly Income Preferred Securities, Series B. On September 22, 2003, we redeemed our entire issuance of Western Resources Capital II 8 1/2% Cumulative Quarterly Income Preferred Securities, Series B, at par. This transaction reduced our long-term liabilities by approximately $115.7 million. We expensed the remaining original unamortized issuance costs of $3.3 million at redemption. See Note 2, “Summary of Significant Accounting Policies,” for a discussion of the current accounting treatment for our mandatorily redeemable preferred securities of subsidiary trusts holding solely company subordinated debentures.

In addition to Westar Energy’s obligations under the Subordinated Debentures discussed above, Westar Energy has guaranteed, on a subordinated basis, payment of distributions on the preferred securities. These undertakings constitute a full and unconditional guarantee by Westar Energy of the trust’s obligations under the preferred securities.

13. DEBT FINANCINGS

On May 10, 2002, we completed offerings for $365.0 million of our first mortgage bonds and $400.0 million of our unsecured senior notes. The entire principal amount of these securities will be due on May 1, 2007. The first mortgage bonds bear interest at an annual rate of $7\,^{7}/_{8}$% and the unsecured senior notes bear interest at an annual rate of $9\,^{3}/_{4}$%. Interest on the first mortgage bonds and unsecured senior notes is payable semi-annually on May 1 and November 1 of each year. The net proceeds from these offerings were used to repay outstanding indebtedness of $547.0 million under our existing secured bank term loan, provide for the repayment of $100.0 million of our 7.25% first mortgage bonds due August 15, 2002 together with accrued interest, reduce the outstanding balance on our existing secured revolving credit facility and pay fees and expenses of the transactions. In conjunction with our May 10, 2002 financing, we amended our secured revolving credit facility to reduce the total commitment under the facility to $400.0 million from $500.0 million and to release $100.0 million of our first mortgage bonds from collateral.

On June 6, 2002, we entered into a secured credit agreement providing for a $585.0 million term loan and a $150.0 million revolving credit facility, each maturing on June 6, 2005, provided that if we have not refinanced or provided for the payment of our 6.875% senior unsecured notes (with an outstanding principal balance of $184.5 million) before June 1, 2004, the secured credit agreement will mature on June 1, 2004. All loans under the credit agreement are secured by KGE's first mortgage bonds. The proceeds of the term loan were used to retire the existing $400.0 million revolving credit facility with an outstanding principal balance of $380.0 million, to provide for the repayment at maturity of $135.0 million principal amount of KGE first mortgage bonds that were due December 15, 2003 together with accrued interest, to repurchase approximately $45.0 million of our outstanding unsecured notes and to pay customary fees and expenses of the transactions.

In February 2004, we repaid the remaining balance of $114.1 million under our $585.0 million term loan that was due in 2005 with internally generated cash and a portion of the proceeds received from the sale of Protection One.

14. CALL OPTION

In August 1998, we entered into a call option with an investment bank related to the issuance of $400.0 million of our 6.25% senior unsecured notes. There notes were putable and callable on August 15, 2003 (the putable/callable notes).

In the second quarter of 2003, we purchased a call option at a cost of $65.8 million, which locked in the settlement cost associated with the August 1998 call option. The outstanding options were settled and the related notes were retired in August 2003. For the year ended December 31, 2003, we recognized a loss related to the putable/callable notes of $21.5 million, which includes a loss of $14.2 million associated with the settlement of the call options.

15. EMPLOYEE BENEFIT PLANS

Pension

We maintain a qualified non-contributory defined benefit pension plans covering substantially all of our utility employees. Pension benefits are based on years of service and the employee's compensation during the five highest paid consecutive years out of ten before retirement. Our policy is to fund pension costs accrued, subject to limitations set by the Employee Retirement Income Security Act of 1974 and the Internal Revenue Code. We also maintain a non-qualified Executive Salary Continuation Plan for the benefit of certain current and retired officers.

As a co-owner of WCNOC, we are indirectly responsible for 47% of the liabilities and expenses associated with the WCNOC pension and post-retirement plans. Our 47% share is included in the tables that follow.

Post-retirement Benefits

We accrue the cost of post-retirement benefits during the years an employee provides service.

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The following tables summarize the status of our pension and other post-retirement benefit plans, including 47% of the WCNOC pension plan:

	Pension Benefits		Post-retirement Benefits	
At December 31,	2003	2002	2003	2002
	(In Thousands)			
Change in Benefit Obligation:				
Benefit obligation, beginning of year	$ 478,139	$ 423,814	$ 128,970	$ 108,630
Obligation for additional plans	—	3,308	—	—
Service cost	7,927	9,149	1,404	1,414
Interest cost	31,761	31,337	8,293	7,739
Plan participants' contributions	—	—	2,353	1,742
Benefits paid	(30,119)	(30,823)	(13,425)	(9,399)
Assumption changes	27,556	23,581	7,911	10,112
Actuarial losses (gains)	3,374	4,900	(4,727)	8,732
Amendments	500	—	—	—
Curtailments, settlements and special term benefits	440	12,873	—	—
Benefit obligation, end of year	$ 519,578	$ 478,139	$ 130,779	$ 128,970
Change in Plan Assets:				
Fair value of plan assets, beginning of year	$ 382,300	$ 467,062	$ 12,629	$ 577
Adjustments	—	—	269	—
Actual return on plan assets	80,213	(58,463)	396	(740)
Employer contribution	2,459	4,524	19,800	20,449
Plan participants' contributions	—	—	2,242	1,742
Benefits paid	(28,241)	(30,823)	(12,793)	(9,399)
Fair value of plan assets, end of year	$ 436,731	$ 382,300	$ 22,543	$ 12,629
Funded status	$ (82,847)	$ (95,839)	$ (108,236)	$ (116,341)
Unrecognized net (gain) loss	66,955	71,877	33,751	31,772
Unrecognized transition obligation, net	455	334	36,218	40,207
Unrecognized prior service cost	18,782	21,631	(1,865)	(2,330)
Post-measurement date adjustments	441	—	—	—
Prepaid (accrued) post-retirement benefit costs	$ 3,786	$ (1,997)	$ (40,132)	$ (46,692)
Amounts Recognized in the Statement of Financial Position Consist Of:				
Prepaid benefit cost	$ 28,976	$ 20,993	$ N/A	$ N/A
Accrued benefit liability	(25,190)	(23,057)	(40,132)	(46,692)
Additional minimum liability	(8,758)	(9,068)	N/A	N/A
Intangible asset	958	1,015	N/A	N/A
Accumulated other comprehensive income	7,800	8,120	N/A	N/A
Net amount recognized	$ 3,786	$ (1,997)	$ (40,132)	$ (46,692)

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At December 31,	Pension Benefits 2003	Pension Benefits 2002	Post-retirement Benefits 2003	Post-retirement Benefits 2002
	(In Thousands)			
Accumulated Benefit Obligation	$ 466,889	$ 412,147	$ N/A	$ N/A
Pension Plans With a Projected Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$ 519,578	$ 478,139	N/A	N/A
Accumulated benefit obligation	466,889	412,147	N/A	N/A
Fair value of plan assets	436,731	382,300	N/A	N/A
Pension Plans With an Accumulated Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$ 73,540	$ 67,092	N/A	N/A
Accumulated benefit obligation	60,528	54,092	N/A	N/A
Fair value of plan assets	26,799	22,276	N/A	N/A
Post-retirement Plans With an Accumulated Post-retirement Benefit Obligation In Excess of Plan Assets:				
Accumulated post-retirement benefit obligation	N/A	N/A	$ 130,779	$ 128,970
Fair value of plan assets	N/A	N/A	22,543	12,629
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Benefit Obligation:				
Discount rate	6.11%	6.75%	6.10%	6.74%
Compensation rate increase	3.11%	3.75%	3.10%	3.75%

We use a measurement date of December 31 for the majority of our pension and post-retirement benefit plans.

The prior service cost (benefit) is amortized on a straight-line basis over the average future service of the active plan participants benefiting under the plan at the time of the amendment. The net actuarial gain (loss) subject to amortization is amortized on a straight-line basis over the average future service of active plan participants benefiting under the plan, without application of the amortization corridor described in SFAS Nos. 87 and 106.

For the Year Ended December 31,	Pension Benefits 2003	Pension Benefits 2002	Pension Benefits 2001	Post-retirement Benefits 2003	Post-retirement Benefits 2002	Post-retirement Benefits 2001
	(In Thousands)					
Components of Net Periodic (Benefit) Cost:						
Service cost	$ 7,927	$ 9,149	$ 9,042	$ 1,404	$ 1,414	$ 1,477
Interest cost	31,761	31,337	28,783	8,293	7,739	7,344
Expected return on plan assets	(42,977)	(44,761)	(43,001)	(1,431)	(52)	(36)
Amortization of unrecognized transition obligation, net	(120)	(194)	34	3,989	3,989	3,987
Amortization of unrecognized prior service costs	3,389	3,327	3,317	(467)	(467)	(466)
Amortization of (gain) loss, net	(1,430)	(5,911)	(8,327)	1,711	992	794
Curtailments, settlements and special term benefits	440	12,873	6,133	—	—	547
Net periodic (benefit) cost	$ (1,010)	$ 5,820	$ (4,019)	$ 13,499	$ 13,615	$ 13,647
Weighted-Average Actuarial Assumptions used to Determine Net Periodic (Benefit) Cost:						
Discount rate	6.75%	7.25%	7.29%	6.74%	7.25%	7.26%
Expected long-term return on plan assets	9.00%	9.02%	9.02%	9.00%	9.00%	9.01%
Compensation rate increase	3.75%	4.25%	4.25%	3.75%	4.25%	4.25%

The expected long-term rate of return on plan assets is based on historical and projected rates of return for current and planned asset classes in the plan's investment portfolio. Assumed projected rates of return for each asset class were selected after analyzing long-term historical experience and future expectations of the volatility of the various asset classes. Based on target asset allocations for each asset class, the overall expected rate of return for the portfolio was developed, adjusted for historical and expected experience
of active portfolio management results compared to benchmark returns and for the effect of expenses paid from plan assets. In selecting the discount rate, fixed income security yield rates for corporate high-grade bond yields are considered.

For measurement purposes, the assumed annual health care cost growth rates, not including any possible additional reduction as a result of the Medicare Prescription Drug Improvement and Modernization Act of 2003 (the Medicare Act), were as follows:

	At December 31, 2003	2002
Health care cost trend rate assumed for next year	9%	10%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	5%	5%
Year that the rate reaches the ultimate trend rate	2007	2007

The health care cost trend rate has a significant effect on the projected benefit obligation. A 1% change in assumed health care cost growth rates would have the following effects:

	1-Percentage-Point Increase	1-Percentage-Point Decrease
	(In Thousands)	
Effect on total of service and interest cost	$ 178	$ (177)
Effect on the present value of the accumulated projected benefit obligation	2,633	(2,625)

In December 2003, the President signed into law the Medicare Act. The Medicare Act introduced a prescription drug benefit under Medicare as well as a federal subsidy to sponsors of post-retirement medical benefits that meet certain criteria. The Medicare Act is expected to ultimately reduce our post-retirement costs from what they would be absent such changes. Detailed regulations pertaining to the Medicare Act have not yet been issued so we cannot determine precisely how we will implement the Medicare Act’s provisions. In addition, accounting guidance regarding the recognition of the impact of the Medicare Act is pending. As permitted by the FASB Staff Position 106-1, we have elected to defer the recognition of the Medicare Act. Consequently, the effects of the Medicare Act are not reflected in the accounting of our post-retirement benefits as of December 31, 2003.

The asset allocation for the pension plans and the post-retirement benefit plans at the end of 2003 and 2002, and the target allocation for 2004, by asset category are as follows:

Asset Category	Target Allocation for 2004	Plan Assets 2003	Plan Assets 2002
Pension Plans:			
Equity securities	65%	67%	61%
Debt securities	30%	30%	33%
Cash and other	5%	3%	6%
Total		100%	100%
Post-retirement Benefit Plans:			
Equity securities	50 – 60%	32%	0%
Debt securities	30 – 40%	34%	0%
Cash and other	0 – 10%	34%	100%
Total		100%	100%

Pension and retiree welfare plan assets are managed in accordance with the “prudent investor” guidelines contained in the Employee Retirement Income Securities Act of 1974 (ERISA). The plan’s investment strategy supports the objective of the funds, which is to earn the highest possible return on plan assets consistent with a reasonable and prudent level of risk. Investments are diversified across classes, sectors and manager style to minimize the risk of large losses. We delegate investment management to specialists in each asset class and where appropriate, provide the investment manager with specific guidelines, which include allowable and/or prohibited investment types. Investment risk is measured and monitored on an ongoing basis through quarterly investment portfolio reviews, annual liability measurements and periodic asset/liability studies.

Expected cash flows:

	Pension Benefits		Post-Retirement Benefits	
	To/From Trust	To/From Company Assets	To/From Trust	To/From Company Assets
	(In Thousands)			
Expected contributions:				
2004	$ 4,100	$ 2,200	$ 20,000	$ 500
Expected benefit payments:				
2004	$ 27,700	$ 2,200	$ 7,500	$ 500
2005	27,100	2,100	8,000	500
2006	26,800	2,100	8,500	600
2007	26,700	2,000	8,600	700
2008	26,700	1,900	8,600	800
2009 - 2013	142,600	9,400	42,000	5,800

Savings Plans

We maintain qualified 401(k) savings plans in which a majority of our employees participate. We match employees' contributions in cash up to specified maximum limits. Our contributions to the plans are deposited with a trustee and are invested at the direction of plan participants into one or more of the investment alternatives we provide under the plan. Our contributions were $3.9 million for 2003, $3.7 million for 2002 and $4.4 million for 2001.

Under our qualified employee stock purchase plan established in 1999, full-time, non-union employees may purchase designated shares of our common stock at no more than a 15% discounted price. Our employees purchased 403,705 shares in 2003 at an average price of $8.45 per share. Employees purchased 46,432 shares in 2002 at an average price of $8.45 per share and employees purchased 67,519 shares at an average price of $14.56 per share in 2001. At December 31, 2003, we had 783,606 shares of our common stock available for issuance under this program.

Stock Based Compensation Plans

We have a long-term incentive and share award plan (LTISA Plan), which is a stock-based compensation plan in which some of our utility employees are eligible for awards. The LTISA Plan was implemented as a means to attract, retain and motivate employees and board members (plan participants). Under the LTISA Plan, we may grant awards in the form of stock options, dividend equivalents, share appreciation rights, restricted shares, RSUs, performance shares and performance share units to plan participants. Up to five million shares of common stock may be granted under the LTISA Plan. At December 31, 2003, awards of 2,154,204 shares of common stock had been made under the LTISA Plan. Dividend equivalents accrue on the awarded RSUs. Dividend equivalents are the right to receive cash equal to the value of dividends paid on our common stock.

In 2003, we granted 547,270 RSUs to board members, officers and some management employees. We granted 584,165 RSUs to a broad-based group of over 800 non-union employees in 2002. Each RSU represents a right to receive one share of our common stock at the end of the restricted period assuming certain criteria are met. In addition, RSUs linked to 783,400 shares of Protection One common stock and 12,193 shares of Guardian International, Inc. preferred stock held by us were granted to certain current and former officers in 2002. During 2001, we granted 579,915 RSUs. The unearned compensation related to the grant of RSUs is shown as a separate component of shareholders' equity. Unearned compensation is being amortized to expense over the vesting period.

During the second quarter of 2002, active employees awarded RSUs in prior years were allowed to exchange eligible RSUs for shares of common stock. As a result, approximately 145,000 RSUs were exchanged for approximately 105,000 shares of our common stock. In addition, approximately 317,000 RSUs held by certain executive officers were exchanged for approximately 12,500 shares of Guardian International, Inc. preferred stock held by us. Compensation expense associated with this exchange totaled approximately $9.0 million for 2002. Also, in September 2002, former employees had the opportunity to convert vested RSUs into common stock. As a result, 34,433 shares of our common stock were issued in exchange for 68,865 RSUs.

Another component of the LTISA Plan is the Executive Stock for Compensation program, where in the past eligible employees were entitled to receive RSUs in lieu of current cash compensation. The Executive Stock for Compensation program was modified in 2001 to pay a portion of current compensation in the form of stock. Although this plan was discontinued, dividends will continue to be paid to plan participants on their outstanding plan balance until distribution. At the end of the deferral period, RSUs are paid in the form of stock. Plan participants were awarded 10,009 shares of common stock for dividends in 2003 and 12,121 shares of common stock for dividends in 2002. In 2001, eligible employees were awarded 31,881 shares of common stock representing $0.7 million of compensation. Participants received common stock distributions of 5,101shares in 2003, 40,097 shares in 2002 and 974 shares in 2001.

Stock options under the LTISA plan are as follows:

	As of December 31,					
	2003		2002		2001	
	Shares (Thousands)	Weighted-Average Exercise Price	Shares (Thousands)	Weighted-Average Exercise Price	Shares (Thousands)	Weighted-Average Exercise Price
Outstanding, beginning of year	232.6	$ 32.08	552.3	$ 34.02	498.3	$ 34.46
Exercised	—	—	(2.6)	18.71	(2.3)	15.31
Forfeited	(5.9)	24.99	(317.1)	35.57	(13.2)	34.54
Adjusted	—	—	—	—	69.5	30.29
Outstanding, end of year	226.7	32.92	232.6	32.08	552.3	34.02

Stock options issued and outstanding at December 31, 2003 are as follows:

	Range of Exercise Price	Number Issued and Outstanding	Weighted-Average Contractual Life in Years	Weighted-Average Exercise Price
Options - Exercisable:				
2000	$15.3125	9,283	7	$ 15.31
1999	27.8125-32.125	22,900	6	29.52
1998	38.625-43.125	55,890	5	41.15
1997	30.75	94,490	4	30.75
1996	29.25	44,095	3	29.25
Total outstanding		226,658		

RSUs under the LTISA plan are as follows:

	As of December 31,					
	2003		2002		2001	
	Shares (Thousands)	Weighted-Average Exercise Price	Shares (Thousands)	Weighted-Average Exercise Price	Shares (Thousands)	Weighted-Average Exercise Price
Outstanding, beginning of year	1,619.9	$ 18.08	1,902.9	$ 22.87	1,607.4	$ 18.90
Granted	547.3	12.9	584.2	13.28	579.9	40.05
Exercised	(251.8)	14.6	(291.8)	18.81	(275.7)	19.08
Forfeited	(1.7)	17.39	(575.4)	28.70	(8.7)	17.86
Outstanding, end of year	1,913.7	16.25	1,619.9	18.08	1,902.9	22.87

RSUs issued and outstanding at December 31, 2003 are as follows:

	Range of Fair Value at Grant Date	Number Issued and Outstanding
Restricted share units:		
2003	$10.20 - $17.75	547,270
2002	9.90 – 19.78	519,191
2001	24.84 – 27.83	197,000
2000	15.3125 – 19.875	517,461
1999	27.8125 – 32.125	63,782
1998	38.625	69,000
Total outstanding		1,913,704

Dividend equivalents were also issued to recipients of stock options and RSUs. Recipients of RSUs receive dividend equivalents when dividends are paid on shares of company stock. The value of each dividend equivalent related to stock options is calculated by accumulating dividends that would have been paid or payable on a share of company common stock. The dividend equivalents, with respect to stock options, expire after nine years from date of grant. The weighted-average fair value at the grant-date of the dividend equivalents on stock options was $6.38 in 2003, $6.35 in 2002 and $6.28 in 2001.

Split Dollar Life Insurance Program

In 1998, we established a split dollar life insurance program for our benefit and the benefit of certain of our former executive officers. Under the program, we purchased life insurance policies, which provide the beneficiary a death benefit in an amount equal to the face amount of the policy reduced by the greater of (i) all premiums paid by the company or (ii) the cash surrender value of the policy, which amount, at the death of the executive, will be returned to us. We retained an economic interest in the death benefit and cash surrender value of the policy to secure this repayment obligation. Policies were purchased under the program only in 1998 and no current officers have received benefits under this program.

Subject to certain conditions, former executive officers may transfer to us their interest in the death benefit based on a predetermined formula. The liability associated with this program was $12.0 million as of December 31, 2003 and remained unchanged from December 31, 2002. The obligations under this program can increase and decrease based on our total return to shareholders and payments to plan participants.

16. INCOME TAXES

Income tax expense (benefit) is composed of the following components at December 31:

	2003	2002	2001
		(In Thousands)	
Current income taxes:			
Federal	$ 84,236	$(153,432)	$(21,942)
State	21,675	(4,432)	(187)
Deferred income taxes:			
Federal	(145,818)	(77,040)	(28,362)
State	(37,719)	8,933	1,181
Investment tax credit amortization	(4,642)	(4,793)	(6,646)
Total	(82,268)	(230,764)	(55,956)
Less taxes classified in:			
Discontinued operations	(164,036)	(146,910)	(41,591)
Cumulative effects of accounting changes	—	(72,335)	12,347
Total income tax expense (benefit)	$ 81,768	$ (11,519)	$(26,712)

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Temporary differences related to deferred tax assets and deferred tax liabilities are summarized in the following table:

	December 31, 2003	December 31, 2002
	(In Thousands)	
Deferred tax assets:		
Deferred gain on sale-leaseback	$ 66,448	$ 71,609
General business credit carryforward (a)	27,524	28,469
Accrued liabilities	19,599	16,860
Disallowed plant costs	14,527	15,587
Long-term energy contracts	12,034	12,814
Protection One Impairment	93,775	—
Other	66,750	83,992
Total deferred tax assets	$ 300,657	$ 229,331
Deferred tax liabilities:		
Accelerated depreciation	$ 666,315	$ 661,673
Acquisition premium	251,163	259,162
Deferred future income taxes	207,812	198,866
Investment tax credits	73,875	79,584
Other	22,071	140,303
Total deferred tax liabilities	$ 1,221,236	$ 1,339,588

(a) Balance represents unutilized tax credits generated from affordable housing partnerships in which we sold the majority of our interests in 2001. These credits expire beginning 2019 through 2023.

Deferred tax assets and liabilities are reflected on our consolidated balance sheets as follows:

	December 31, 2003	December 31, 2002
	(In Thousands)	
Current deferred tax assets, net	$ 119,041	$ —
Current deferred tax liabilities, net	—	13,580
Non-current deferred tax liabilities, net	1,039,620	1,096,677
Net deferred tax liabilities	$ 920,579	$ 1,110,257

In accordance with various rate orders, we have not yet collected through rates certain accelerated tax deductions, which have been passed on to customers. We believe it is probable that the net future increases in income taxes payable will be recovered from customers. We have recorded a regulatory asset for these amounts. These assets are also a temporary difference for which deferred income tax liabilities have been provided. This liability is classified above as deferred future income taxes.

The effective income tax rates set forth below are computed by dividing total federal and state income taxes by the sum of such taxes and net income. The difference between the effective tax rates and the federal statutory income tax rates are as follows:

	For the Year Ended December 31,		
	2003	2002	2001
Statutory federal income tax rate	35.0%	35.0%	35.0%
Effect of:			
State income taxes	4.3	2.8	0.1
Amortization of investment tax credits	(1.9)	(6.2)	(20.4)
Corporate-owned life insurance policies	(5.0)	(15.0)	(41.9)
Affordable housing tax credits	(0.1)	(0.2)	(29.9)
Accelerated depreciation flow through and amortization	2.2	6.4	0.2
Dividends received deduction	(1.7)	(12.6)	(31.3)
Settlement of outstanding state income tax issue	—	(27.4)	—
Other	0.6	2.3	6.3
Effective income tax rate	33.4%	(14.9)%	(81.9)%

17. COMMITMENTS AND CONTINGENCIES

Purchase Orders and Contracts

As part of our ongoing operations and construction program, we have purchase orders and contracts, excluding fuel (which is discussed below under "—Fuel Commitments,") that have an unexpended balance of approximately $125.4 million at December 31, 2003, of which $30.9 million has been committed. The $30.9 million commitment relates to purchase obligations issued and outstanding at year-end.

The aggregate amount of required payments at December 31, 2003 was as follows:

	Committed Amount
	(In Thousands)
2004	$ 20,557
2005	8,236
2006	2,183
2007	7
2008	—
Thereafter	1
	$ 30,984

Clean Air Act

Generally, we must comply with the Clean Air Act, state laws and implementing regulations that impose, among other things, limitations on major pollutants, including sulfur dioxide (SO2), particulate matter and nitrogen oxides (NOx). In addition, we must comply with the provisions of the Clean Air Act Amendments of 1990 that require a two-phase reduction in some emissions. We have installed continuous monitoring and reporting equipment in order to meet the acid rain requirements. We have not had to make any material capital expenditures to meet Phase II SO2 and NOx requirements.

Manufactured Gas Sites

We have been associated with a number of former manufactured gas sites located in Kansas and Missouri that may contain coal tar and other potentially harmful materials.

We and the Kansas Department of Health and Environment (KDHE) entered into a consent agreement in 1994 governing all future work at the Kansas sites. Under the terms of the consent agreement, we agreed to investigate and remediate, if necessary, these sites. Through December 31, 2003, the costs incurred for preliminary site investigation and risk assessment have been minimal. Pursuant to an environmental indemnity agreement with ONEOK, the current owner of some of the Kansas sites, our liability for twelve of the Kansas sites is limited. Of those twelve sites, ONEOK assumed total liability for remediation of seven sites and we share liability for remediation with ONEOK for five sites. Our total liability for the five shared sites is capped at $3.8 million and terminates in 2012. We have sole responsibility for remediation with respect to three Kansas sites. With respect to two of those sites, we are currently either conducting or completing remediation activities and, with respect to the third site, we will begin investigation activities in the near future.

Our liability for our former manufactured gas sites in Missouri is limited by an environmental indemnity agreement with Southern Union Company, which bought all of the Missouri manufactured gas sites. According to the terms of the agreement, our future liability for these sites is capped at $7.5 million and terminates in 2009.

EPA New Source Review

The United States Environmental Protection Agency (EPA) is conducting numerous investigations nationwide to determine whether modifications at coal-fired power plants are subject to New Source Review requirements or New Source Performance Standards under Section 114(a) of the Clean Air Act (Section 114). These investigations focus on whether projects at coal-fired plants were routine maintenance or whether the projects were substantial modifications that could have reasonably been expected to result in a significant net increase in emissions. The Clean Air Act requires companies to obtain permits and, if necessary, install control equipment to remove emissions when making a major modification or a change in operation if either is expected to cause a significant net increase in emissions.

The EPA has requested information from us under Section 114 regarding projects and maintenance activities that have been conducted since 1980 at the three coal-fired plants we operate. On January 22, 2004, the EPA notified us that certain projects completed at Jeffrey Energy Center violated pre-construction permitting requirements of the Clean Air Act.

We are in discussions with the EPA concerning this matter but are unable to predict whether the EPA will take further enforcement action. We will attempt to reach a settlement agreement with the EPA. However, if a settlement cannot be reached, the EPA could refer the matter to the United States Department of Justice for it to consider whether to pursue an enforcement action. If we are required to pay any fines or penalties or update or install emissions controls at Jeffrey Energy Center or the other coal-fired plants or take other remedial action, these costs could be material. We believe that costs related to updating or installing emissions controls would qualify for recovery through rates. If we are assessed a penalty as a result of the EPA's allegation, the penalty could be material and may not be recovered in rates.

Solid Waste Landfills

We have operating solid waste landfills at Jeffrey Energy Center, Tecumseh Energy Center and Lawrence Energy Center for the single purpose of disposing of coal combustion waste material. Additionally, there is one retired landfill at each of the Lawrence and Neosho Energy Centers. All landfills are permitted by the KDHE. The operating landfill at Lawrence Energy Center is projected to be full by 2007 requiring us to permit and construct a new landfill at this site. It is anticipated that the lead-time for permitting a new landfill may be significant. We began the process of obtaining this permit in late 2003 but can offer no assurance as to when or if we will obtain the permit.

Nuclear Decommissioning

Nuclear decommissioning is a nuclear industry term for the permanent shutdown of a nuclear power plant and the removal of radioactive components in accordance with Nuclear Regulatory Commission (NRC) requirements. The NRC will terminate a plant's license and release the property for unrestricted use when a company has reduced the residual radioactivity of a nuclear plant to a level mandated by the NRC. The NRC requires companies with nuclear plants to prepare formal financial plans to fund nuclear decommissioning. These plans are designed so that funds required for nuclear decommissioning will be accumulated prior to the termination of the license of the related nuclear power plant.

We accrue nuclear decommissioning costs over the expected life of the Wolf Creek generating facility. The amount we accrue is based on the decommissioning costs approved by the KCC to be included in rates. Decommissioning costs that are recovered in rates are deposited in an external trust fund.

The KCC reviews nuclear decommissioning plans in two phases. Phase one is the approval of the nuclear decommissioning study, the current year dollar amount of funding and the future year dollar amount of funding. Phase two is the filing of a "funding schedule" by the owner of the nuclear facility detailing how it plans to fund the future year dollar amount for the pro rata share of the plant.

An updated nuclear decommissioning and dismantlement cost estimate was filed with the KCC on August 30, 2002. Estimated costs outlined by this study were developed to decommission Wolf Creek following a shutdown. The analyses relied on site-specific, technical information, updated to reflect current plant conditions and operating assumptions. Based on this study, our share of Wolf Creek's nuclear decommissioning costs, under the immediate dismantlement method, is estimated to be approximately $220.0 million in 2002 dollars. These costs include decontamination, dismantling and site restoration and are not inflated, escalated, or discounted over the period of expenditure. The actual nuclear decommissioning costs may vary from the estimates because of changes in technology and changes in costs for labor, materials and equipment.

The KCC issued an order on April 16, 2003 approving the August 2002 nuclear decommissioning study for Wolf Creek. On June 2, 2003, we filed a funding schedule with the KCC to reflect the KCC's April 16, 2003 order. On October 10, 2003, the KCC approved the funding schedule as filed without any change to our funding obligation.

Nuclear decommissioning costs are currently being charged to operating expense in accordance with the July 25, 2001 KCC rate order as modified by the KCC's approval of the funding schedule in the KCC's October 13, 2003 order. Electric rates charged to customers provide for recovery of these nuclear decommissioning costs over the life of Wolf Creek as determined by the KCC through 2045. The NRC requires that funds to meet its nuclear decommissioning funding assurance requirement be in our nuclear decommissioning fund by the time our license expires in 2025. We believe that the KCC approved funding level will be sufficient to meet the NRC minimum financial assurance requirement. However, our consolidated results of operations would be materially adversely affected if we are not allowed to recover the full amount of the funding requirement.

Nuclear decommissioning amounts expensed in 2003 approximated $3.9 million. The amounts collected are deposited in an external trust fund. The average after-tax expected return on trust assets is 5.7%.

Our investment in the nuclear decommissioning fund is recorded at fair value, including reinvested earnings. It approximated $80.1 million at December 31, 2003 and $63.5 million at December 31, 2002. Trust fund earnings accumulate in the fund balance and increase the recorded nuclear decommissioning liability.

Storage of Spent Nuclear Fuel

Under the Nuclear Waste Policy Act of 1982, the Department of Energy (DOE) is responsible for the permanent disposal of spent nuclear fuel. As required by federal law, the WCNOC co-owners entered into a standard contract with the DOE in 1984 in which the DOE promised to begin accepting from commercial nuclear power plants their used nuclear fuel for disposal beginning in early 1998. In return, Wolf Creek pays into a federal Nuclear Waste Fund administered by the DOE a quarterly fee of one-tenth of a cent for each kilowatt-hour of net nuclear generation delivered to customers for the future disposal of spent nuclear fuel. From 1985 through December 2003, the WCNOC co-owners have paid slightly over $144.7 million into the Nuclear Waste Fund. Our share of these disposal costs are charged to cost of sales.

A permanent disposal site will not be available for the nuclear industry until 2010 or later. Under current DOE policy, once a permanent site is available, the DOE will accept spent nuclear fuel on a priority basis. The owners of the oldest spent fuel will be given the highest priority. As a result, disposal services for Wolf Creek will not be available prior to 2016. Wolf Creek has on-site temporary storage for spent nuclear fuel. In early 2000, Wolf Creek completed replacement of spent fuel storage racks to increase its on-site storage capacity for all spent fuel expected to be generated by Wolf Creek through the end of its licensed life in 2025.

In mid-2002, Congress passed and the President signed a resolution approving the Yucca Mountain site in Nevada for the development of a nuclear waste repository for the disposal of spent nuclear fuel and high level nuclear waste from the nation's defense activities. This action allows the DOE to apply to the NRC to license the project. The DOE expects that this facility will open in 2010. However, the opening of the Yucca Mountain site could be delayed due to litigation and other issues related to the site as a permanent repository for spent nuclear fuel.

Nuclear Insurance

We maintain nuclear insurance for Wolf Creek in four areas: liability, worker radiation, property and accidental outage. These policies contain certain industry standard exclusions, including, but not limited to, ordinary wear and tear and war. Terrorist acts are not excluded from the property and accidental outage policies, but are covered as a common occurrence under the Non-Terrorism Risk Insurance Act. The term common occurrence means that if terrorist acts occur against one or more commercial nuclear power plants insured by our insurance company within a 12-month period, all of these terrorist acts will be treated as one event and the owners of the plants will share one full limit of each type of policy, which is currently $3.24 billion plus any reinsurance recoverable by Nuclear Electric Insurance Limited (NEIL), our insurance provider. Currently there is $1 billion of reinsurance purchased by NEIL. Claims that arise from terrorist acts are also covered by our nuclear liability and worker radiation policies. These policies are subject to one industry aggregate limit for such acts, currently $300.0 million for the risk of terrorism. Unlike the property and accidental outage policies, an industry-wide retrospective assessment program (discussed below) applies once the nuclear liability and worker radiation policies have been exhausted.

Nuclear Liability Insurance

Pursuant to the Price-Anderson Act, we are required to insure against public liability claims resulting from nuclear incidents to the full limit of public liability, which is currently approximately $10.9 billion. This limit of liability consists of the maximum available commercial insurance of $300.0 million, and the remaining $10.6 billion is provided through mandatory participation in an industry-wide retrospective assessment program. Under this retrospective assessment program, we can be assessed up to $100.6 million per incident at any commercial reactor in the country, payable at no more than $10.0 million per incident per year. This assessment is subject to an inflation adjustment based on the Consumer Price Index and applicable premium taxes. This assessment also applies in excess of our worker radiation claims insurance. In addition, the United States Congress could impose additional revenue-raising measures to pay claims. If the $10.9 billion liability limitation is insufficient, the United States Congress will consider taking whatever action is necessary to compensate the public for valid claims.

The Price-Anderson Act expired in August 2002 but was extended until December 31, 2003 for Licensees. Licensees such as Wolf Creek continue to be grandfathered under the Act. The current version of a comprehensive energy bill expected to be adopted in 2004 by Congress contains provisions that would amend Federal Law (the "Price-Anderson Act") addressing public liability from nuclear energy hazards in ways that would increase the annual limit on retrospective assessments from $10.0 million to $15.0 million per reactor per incident.

Nuclear Property Insurance

The owners of Wolf Creek carry decontamination liability, premature nuclear decommissioning liability and property damage insurance for Wolf Creek totaling approximately $2.8 billion (our share is $1.3 billion). This insurance is provided by NEIL. In the event of an accident, insurance proceeds must first be used for reactor stabilization and site decontamination in accordance with a plan mandated by the NRC. Our share of any remaining proceeds can be used to pay for property damage or decontamination expenses or, if certain requirements are met, including nuclear decommissioning the plant, toward a shortfall in the nuclear decommissioning trust fund.

Accidental Nuclear Outage Insurance

The owners also carry additional insurance with NEIL to cover costs of replacement power and other extra expenses incurred during a prolonged outage resulting from accidental property damage at Wolf Creek. If significant losses were incurred at any of the nuclear plants insured under the NEIL policies, we may be subject to retrospective assessments under the current policies of approximately $25.2 million (our share is $11.8 million).

Although we maintain various insurance policies to provide coverage for potential losses and liabilities resulting from an accident or an extended outage, our insurance coverage may not be adequate to cover the costs that could result from a catastrophic accident or extended outage at Wolf Creek. Any substantial losses not covered by insurance, to the extent not recoverable through rates, would have a material adverse effect on our consolidated financial condition and results of operations.

Fuel Commitments

To supply a portion of the fuel requirements for our generating plants, we have entered into various commitments to obtain nuclear fuel and coal. Some of these contracts contain provisions for price escalation and minimum purchase commitments. At December 31, 2003, our share of WCNOC's nuclear fuel commitments were approximately $17.6 million for uranium concentrates expiring in 2007, $2.8 million for conversion expiring in 2007, $15.3 million for enrichment expiring at various times through 2006 and $55.9 million for fabrication through 2024.

At December 31, 2003, our coal and coal transportation contract commitments in 2003 dollars under the remaining terms of the contracts were approximately $1.9 billion. The largest contract expires in 2020, with the remaining contracts expiring at various times through 2013.

At December 31, 2003, our natural gas transportation commitments in 2003 dollars under the remaining terms of the contracts were approximately $49.0 million. The natural gas transportation contracts provide firm service to several of our natural gas burning facilities and expire at various times through 2010, except for one contract that expires in 2016.

Energy Act

As part of the 1992 Energy Policy Act, a special assessment is being collected from utilities for a uranium enrichment decontamination and nuclear decommissioning fund. Our portion of the assessment, including carrying costs, for Wolf Creek is approximately $9.6 million. To date, we have paid approximately $7.5 million, with the remainder payable over the next three years. Such costs are recovered through the ratemaking process.

18. ASSET RETIREMENT OBLIGATIONS

In January 2003, we adopted SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 requires recognition of legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development or normal operation of such assets. Concurrent with the recognition of the liability, the estimated cost of an asset retirement obligation is capitalized and depreciated over the remaining life of the asset. Any income effects are offset by regulatory accounting pursuant to SFAS No. 71.

Legal Liability - Wolf Creek

On January 1, 2003, we recognized the liability for our 47% share of the estimated cost to decommission Wolf Creek. SFAS No. 143 requires the recognition of the present value of the asset retirement obligation we incurred at the time Wolf Creek was placed into service in 1985. On January 1, 2003, we recorded an asset retirement obligation of $74.7 million. In addition, we increased our property and equipment balance, net of accumulated depreciation, by $10.7 million. We also established a regulatory asset for $64.0 million, which represents the accretion of the liability since 1985 and the increased depreciation expense associated with the increase in plant. The asset retirement obligation is included on our consolidated balance sheets in other long-term liabilities. Costs to retire Wolf Creek are currently being recovered through rates as provided by the KCC.

The following table is a reconciliation of the legal asset retirement obligation related to the decommissioning of WCNOC, which is included on our consolidated balance sheets in other long-term liabilities:

	As of December 31, 2003
	(In Thousands)
Beginning asset retirement obligation	$ —
Transition liability	74,745
Liabilities settled	—
Accretion expense	5,950
Estimated cash flows revisions	—
Ending asset retirement obligation	$ 80,695

The following presents pro forma asset retirement obligation information as if SFAS No. 143 had been adopted at January 1, 2002:

	As of December 31, 2003	As of December 31, 2002
	(In Thousands)	
Liabilities incurred:		
Reported	$ 80,695	$ —
Pro forma	80,695	74,745

Non-legal Liability - Cost of Removal

We have recovered amounts in rates to provide for recovery of the probable costs of removing utility plant assets, but which do not represent legal retirement obligations. The amounts recovered were included as a component of depreciation expense in accordance with the FERC and KCC required ratemaking treatment. With the adoption of SFAS No. 143 we were required to quantify the net cost of removal included in accumulated depreciation. At December 31, 2002, we had $15.2 million included in accumulated depreciation that has been reclassified to other assets. At December 31, 2003, we had $6.6 million in removal costs that have been classified as a regulatory asset. The net amount related to non-legal retirement costs can fluctuate based on amounts related to removal costs recovered compared to removal costs incurred. Therefore, if in the future we recover removal costs in excess of amounts incurred we will recognize a regulatory liability for that amount. We do not anticipate that the adoption of SFAS No. 143 will have any impact on our electric rates.

19. LEGAL PROCEEDINGS

We and certain of our present and former officers are defendants in a consolidated purported class action lawsuit in United States District Court in Topeka, Kansas, “In Re Westar Energy, Inc. Securities Litigation,” Master File No. 5:03-CV-4003 and related cases. Plaintiffs filed a Consolidated Amended Complaint on July 15, 2003. The lawsuit is brought on behalf of purchasers of our common stock between March 29, 2000, the date we announced our intention to separate our electric utility operations from our unregulated businesses, and November 8, 2002, the date the KCC issued an order prohibiting the separation. The lawsuit alleges that we violated federal securities laws by making material misrepresentations, or omitting material facts, concerning the purpose and benefits of the previously proposed separation of our electric utility operations from our unregulated businesses, the compensation of our senior management and the independence and functioning of our board of directors and that as a result we artificially inflated the price of our common stock. On October 20, 2003, we and the other defendants filed motions to dismiss the complaint. Responses by the plaintiffs are due on March 15, 2004. We intend to vigorously defend against this action. We are unable to predict the ultimate impact of this matter on our consolidated financial position, results of operations and cash flows.

We and certain of our present and former officers and employees are defendants in a consolidated purported class action lawsuit filed in United States District Court in Topeka, Kansas, “In Re Westar Energy ERISA Litigation, Master File No. 03-4032-JAR.” Plaintiffs filed a Consolidated Amended complaint on October 20, 2003. The lawsuit is brought on behalf of participants in, and beneficiaries of, our Employees' 401(k) Savings Plan between July 1, 1998 and January 1, 2003. The lawsuit alleges violations of the Employee Retirement Income Security Act arising from the conduct of certain present and former officers and employees who served or are serving as fiduciaries for the plan. The conduct is related to alleged securities law violations related to the previously proposed separation of our electric utility operations from our unregulated businesses, our rate cases filed with the KCC in 2000, the compensation of and benefits provided to our senior management, energy marketing transactions with Cleco Corporation (Cleco) and the first and second quarter 2002 restatements of our consolidated financial statements related to the revised goodwill impairment charge and the mark-to-market charge on our putable/callable notes. On December 23, 2003, we filed a motion to dismiss the complaint. Certain other defendants have until March 30, 2004 to file motions to dismiss. Plaintiffs have until May 17, 2004 to file a response to the motions to dismiss. We intend to vigorously defend against this action. We are unable to predict the ultimate impact of this matter on our consolidated financial position, results of operations and cash flows.

Certain present and former members of our board of directors and officers are defendants in a shareholder derivative complaint filed April 18, 2003, "Mark Epstein vs David C. Wittig, Douglas T. Lake, Charles Q. Chandler IV, Frank J. Becker, Gene A. Budig, John C. Nettels, Jr., Roy A. Edwards, John C. Dicus, Carl M. Koupal, Jr., Larry D. Irick and Cleco Corporation, defendants, and Westar Energy, Inc., nominal defendant, Case No. 03-4081-JAR." Plaintiffs filed an amended shareholder derivative complaint on July 30, 2003. Among other things, the lawsuit claims that the defendants (a) breached fiduciary duties owed to us because of the actions and omissions described in the report of the special committee of our board of directors (see Note 21 below), (b) caused or permitted our assets to be wasted on perquisites for certain insiders and (c) caused or permitted our May 6, 2002 proxy statement to be issued with materially false and misleading statements. The plaintiffs seek unspecified monetary damages and other equitable relief. In October 2003, our board of directors appointed a special litigation committee of the board to evaluate the amended shareholder derivative complaint. The members of the committee are Mollie Hale Carter, Arthur B. Krause and Michael F. Morrissey. Defendants who have not already filed a response to the complaint have until April 23, 2004 to respond. We are unable to predict the ultimate impact of this matter on our consolidated financial position, results of operations and cash flows.

On June 13, 2003, we filed a demand for arbitration with the American Arbitration Association asserting claims against Mr. Wittig and Mr. Lake arising out of their previous employment with us. Mr. Wittig and Mr. Lake have filed counterclaims against us in the arbitration alleging substantial damages related to the termination of their employment and the publication of the report of the special committee of our board of directors. We intend to vigorously defend against these claims. We are unable to predict the ultimate impact of this matter on our consolidated financial position, consolidated results of operations and cash flow.

We and our subsidiaries are involved in various other legal, environmental and regulatory proceedings. We believe that adequate provisions have been made and accordingly believe that the ultimate disposition of such matters will not have a material adverse effect on our consolidated financial position or results of operations.

See also Notes 3, 17, 20, 21 and 23 for discussion of KCC regulatory proceedings, alleged violations of the Clean Air Act, an investigation by the United States Attorney's Office, an inquiry by the Securities and Exchange Commission (SEC), an investigation by the FERC of certain of our power transactions, a special committee investigation and potential liabilities to Mr. Wittig and Mr. Lake.

20. ONGOING INVESTIGATIONS

Grand Jury Subpoena

On September 17, 2002, we were served with a federal grand jury subpoena by the United States Attorney's Office in Topeka, Kansas, requesting information concerning the use of aircraft and our annual shareholder meetings. Since that date, the United States Attorney's Office has served additional subpoenas on us and certain of our employees requesting further information concerning the use of our aircraft; executive compensation arrangements with Mr. Wittig, Mr. Lake and other former and present officers; the proposed rights offering of Westar Industries stock that was abandoned; and the company in general. We are providing information in response to these requests and we are cooperating fully in the investigation. We have not been informed that we are a target of the investigation. On December 4, 2003, Mr. Wittig and Mr. Lake were indicted by the federal grand jury on conspiracy, fraud and other criminal charges related to their actions while serving as our officers. We are unable to predict the ultimate outcome of the investigation or its impact on us.

Securities and Exchange Commission Inquiry

On November 1, 2002, the SEC notified us that it would be conducting an inquiry into the matters involved in the restatement of our first and second quarter 2002 financial statements. Our counsel has communicated with the SEC about these and other matters within the scope of the grand jury investigation, including disclosures in our proxy statements concerning personal aircraft use by former officers and the payment of a bonus to Mr. Wittig in 2002. We are unable to predict the ultimate outcome of the inquiry or its impact on us.

FERC Subpoena

On December 16, 2002, we received a subpoena from the FERC seeking details on power trades with Cleco and its affiliates, documents concerning power transactions between our system and our marketing operations and information on power trades in which we or other trading companies acted as intermediaries.

Cleco publicly disclosed in November 2002 that Cleco and its affiliates had engaged in certain trades that may have violated the FERC affiliate transaction rules applicable to Cleco. The affiliate transactions involved power sales from one Cleco affiliate to Westar Energy and then back to another or the same Cleco affiliate. The transactions totaled approximately $3.8 million in 2002, $12.6 million in 2001 and $3.4 million in 2000. The total amount of these transactions represented less than 1% of our total revenues in 2002, 2001 and 2000.

Among the issues being reviewed by the FERC are transactions we conducted with third parties to facilitate power transfers between our system and our marketing operations. These transactions and other energy marketing and trading activities were recently reviewed in a KCC ordered audit of our energy marketing operations. This review was conducted by an independent third party with industry experience who was approved by the KCC. The review found no irregularities in the structure or pricing of the transactions.

We have provided information to the FERC in response to the original subpoena, subsequent requests submitted through our counsel and additional subpoenas received July 28, 2003 and October 27, 2003 seeking information about compliance with the FERC codes of conduct applicable to generation and transmission activities. We believe that our participation in these transactions and the conduct of our generation and transmission operations did not violate the FERC rules and regulations. However, we are unable to predict the ultimate outcome of the investigation.

21. SPECIAL COMMITTEE INVESTIGATION

In September 2002, our board of directors appointed a special committee of directors to investigate matters related to a federal grand jury subpoena served on us by the United States Attorney's Office in Topeka, Kansas, requesting information concerning the use of our corporate aircraft and our annual shareholder meetings. The scope of the special committee's investigation was expanded to cover other matters that were the subject of additional United States Attorney's Office subpoenas served on us and certain of our employees. These matters included executive compensation arrangements with David C. Wittig, our former chairman of the board, president and chief executive officer, and Douglas T. Lake, our former executive vice president, chief strategic officer and member of the board, and other former and present officers; the proposed rights offering of Westar Industries stock that was abandoned; and the company in general. The investigation also included matters that were the subject of an SEC inquiry into the restatement of our first and second quarter 2002 consolidated financial statements and disclosures in our proxy statements concerning personal aircraft use by former officers and the payment of a bonus to Mr. Wittig in 2002. The special committee completed its investigation and publicly released a report on May 14, 2003 concerning the conclusions and recommendations reached as a result of the investigation. The investigation did not result in adjustments to our previously filed financial statements.

22. COMMON AND PREFERRED STOCK

Our Restated Articles of Incorporation, as amended, provide for 150,000,000 authorized shares of common stock. At December 31, 2003, 72,840,217 shares were issued and 72,636,642 shares were outstanding.

We have a Direct Stock Purchase Plan (DSPP). Shares issued under the DSPP may be either original issue shares or shares purchased in the open market. During 2003, a total of 1,129,689 shares were purchased from the company through the reissuance of treasury shares for the DSPP, Employee Stock Purchase Plan, 401(k) match and other stock based plans operated under the 1996 Long-Term Incentive and Share Award Plan. At December 31, 2003, a total of 992,488 shares were available under the DSPP registration statement.

Treasury Stock

At December 31, 2003, we had a treasury stock balance of 203,575 shares. At December 31, 2002, we had a treasury stock balance of 1,333,264 including 850,000 shares held by Protection One. During 2003, we repurchased all of these shares from Protection One for the then current market value which was $3.4 million less than what Protection One originally paid.

See Note 26, “Related Party Information,” for information regarding our purchase during 2003 of shares of our common stock held by Protection One.

Preferred Stock Not Subject to Mandatory Redemption

Westar Energy’s cumulative preferred stock is redeemable in whole or in part on 30 to 60 days’ notice at our option. The table below shows our redemption amount for all series of preferred stock not subject to mandatory redemption at December 31, 2003.

Rate	Shares	Principal Outstanding	Call Price	Premium	Total Amount to Redeem
			(Dollars in Thousands)		
4.500%	121,613	$ 12,161	108.00%	$ 973	$ 13,134
4.250%	54,970	5,497	101.50%	82	5,579
5.000%	37,780	3,778	102.00%	76	3,854
		$ 21,436		$ 1,131	$ 22,567

The provisions of Westar Energy’s Restated Articles of Incorporation, as amended, contain restrictions on the payment of dividends or the making of other distributions on our common stock while any preferred shares remain outstanding unless certain capitalization ratios and other conditions are met. If the ratio of the capital represented by our preference stock and common stock (together, Subordinated Stock) (including premiums on our capital stock) and its surplus accounts, to its total capital and its surplus accounts at the end of the second month immediately preceding the date of the proposed payment of dividends, adjusted to reflect the proposed payment (Capitalization Ratio), will be less than 20%, then the payment of the dividends on Subordinated Stock shall not exceed 50% of net income available for dividends for the 12-month period ending with and including the second month immediately preceding the date of the proposed payment. If the Capitalization Ratio is 20% or more but less than 25%, then the payment of dividends on the Subordinated Stock, including the proposed payment, then the payments shall not exceed 75% of its net income available for dividends for such 12-month period. Except to the extent permitted above, no payment or other distribution may be made that would reduce the Capitalization Ratio to less than 25%. The Capitalization Ratio is determined based on the unconsolidated balance sheet for Westar Energy. At December 31, 2003, the Capitalization Ratio was greater than 25%.

So long as there are any outstanding shares of Westar Energy preferred stock, Westar Energy shall not without the consent of a majority of the shares of preferred stock or if more than one-third of the outstanding shares of preferred stock vote negatively and without the consent of a percentage of any and all classes required by law and Westar Energy’s Articles of Incorporation, declare or pay any dividends (other than stock dividends or dividends applied by the recipient to the purchase of additional shares) or make any other distribution upon Subordinated Stock unless, immediately after such distribution or payment the sum of Westar Energy’s capital represented by the outstanding Subordinated Stock and our earned and any capital surplus shall not be less than $10.5 million plus an amount equal to twice the annual dividend requirement on all the then outstanding shares of preferred stock.

23. POTENTIAL LIABILITIES TO DAVID C. WITTIG AND DOUGLAS T. LAKE

David C. Wittig, our former chairman of the board, president and chief executive officer, resigned from all of his positions with us and our affiliates on November 22, 2002. On May 7, 2003, our board of directors determined that the employment of Mr. Wittig was terminated as of November 22, 2002 for cause. Douglas T. Lake, our former executive vice president, chief strategic officer and member of the board, was placed on administrative leave from all of his positions with us and our affiliates on December 6, 2002. On June 12, 2003, our board of directors terminated the employment of Mr. Lake for cause.

On June 13, 2003, we filed a demand for arbitration with the American Arbitration Association asserting claims against Mr. Wittig and Mr. Lake arising out of their previous employment with us. Among other things, we are seeking to recover compensation and benefits previously paid to Mr. Wittig and Mr. Lake and to avoid compensation and other benefits Mr. Wittig and Mr. Lake claim to be owed to them as a result of their previous employment with us. We are unable to predict the outcome of the arbitration.

As of December 31, 2003, we had accrued liabilities totaling approximately $51.5 million for compensation not yet paid to Mr. Wittig and Mr. Lake under various plans. The compensation includes RSU awards, deferred vested shares, deferred RSU awards, deferred vested stock for compensation, executive salary continuation plan benefits and, in the case of Mr. Wittig, benefits arising from a split dollar life insurance agreement. The amount of our obligation to Mr. Wittig related to a split dollar life insurance agreement is subject to adjustment at the end of each quarter based on the total return to our shareholders from the date of that agreement. The total return considers the change in stock price and accumulated dividends.

In January 2004, stock performance requirements were satisfied resulting in the vesting of RSUs previously granted to Mr. Wittig and Mr. Lake. Accordingly, in January 2004 we recorded compensation expense of $4.2 million and increased our accrued liability to Mr. Wittig and Mr. Lake by a like amount.

In addition to these amounts, we could also be obligated to make payments to Mr. Wittig and Mr. Lake pursuant to the executive salary continuation plan. Assuming an expected payout period of 35 years, the aggregate nominal amount of these payments would be approximately $17.3 million for Mr. Wittig and $8.6 million for Mr. Lake.

24. MARKETABLE SECURITIES

On January 1, 2003, we classified our investment in ONEOK as an available-for-sale security and by December 31, 2003, had sold all of our investment in ONEOK. Realized gains and losses on the sale of our marketable securities are included in earnings and were derived using the specific identification method. The following table summarizes our marketable security sales for the years ended December 31, 2003, 2002 and 2001:

	Marketable Security Sales		
	2003	2002	2001
		(In Thousands)	
Sales proceeds	$ 801,841	$—	$2,829
Realized gains	99,327	—	—
Realized losses	—	—	1,861

During each of the last three years, we wrote down the cost basis of certain other securities to their estimated fair value. The fair value of these equity securities had declined below our cost basis, and we determined that these declines were other than temporary. The write down for 2003 totaled $0.5 million. For 2002, the write down totaled $0.3 million. The amount of the 2001 write down totaled $11.1 million. The write downs are included in impairment of investments on our consolidated statements of income.

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25. LEASES

Operating Leases

We lease office buildings, computer equipment, vehicles, railcars and other property and equipment with various terms and expiration dates ranging from 1 to 15 years. We have the right at the expiration of the basic lease terms to renew several leases, including the LaCygne 2 lease, static var equipment lease, and several railcar leases. We also have the right to purchase the equipment or assets at the expiration of the basic lease term or any renewal term at a price equal to the fair market value of the equipment if certain notification requirements are met.

In determining lease expense, the effects of scheduled rent increases are recognized on a straight-line basis over the minimum lease term. The rental expense associated with the LaCygne 2 operating lease includes an offset for the amortization of the deferred gain on the sale-leaseback. The rental expense and estimated commitments are as follows for the LaCygne 2 lease and other operating leases.

Year Ended December 31,	LaCygne 2 Lease (a)	Total Operating Leases
	(In Thousands)	
Rental expense:		
2001	$ 28,895	$ 53,956
2002	28,895	46,312
2003	28,895	42,495
Future commitments:		
2004	$ 34,598	$ 45,106
2005	38,013	47,633
2006	42,287	51,570
2007	78,268	85,282
2008	12,609	19,085
Thereafter	331,441	365,634
Total future commitments	$ 537,216	$ 614,310

(a) LaCygne 2 lease amounts are included in total operating leases

In 1987, KGE sold and leased back its 50% undivided interest in the LaCygne 2 generating unit. The LaCygne 2 lease had an initial term of 29 years, with various options to renew the lease or repurchase the 50% undivided interest. KGE remains responsible for its share of operating and maintenance costs and other related operating costs of LaCygne 2. The lease is an operating lease for financial reporting purposes. We recognized a gain on the sale, which was deferred and is being amortized over the lease term. The increase in payments in 2006 and 2007 represent a change in accordance with the terms of the lease from the lease payments being made in arrears to the lease payments being made in advance and are included on a straight-line basis over the minimum lease term when determining lease expense. The rent liability associated with the LaCygne 2 lease is included in the accrued liability line on the consolidated balance sheets and was $32.5 million at December 31, 2003 and $32.4 million at December 31, 2002.

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Capital Leases

Assets recorded under capital leases are listed below:

	December 31,	
	2003	2002
	(In Thousands)	
Vehicles	$ 40,018	$ 41,930
Computer systems and software	958	6,557
Accumulated amortization	(18,383)	(21,131)
	$ 22,593	$ 27,356

Minimum annual rental payments, excluding administrative costs such as property taxes, insurance and maintenance, under capital leases as of December 31, 2003 are listed below. Some capital leases are subject to covenants, which require us to maintain certain credit ratings.

Year Ended December 31,	Total Capital Leases
	(In Thousands)
2004	$ 5,294
2005	4,632
2006	3,841
2007	3,432
2008	2,607
Thereafter	5,522
	25,328
Amounts representing imputed interest	(2,735)
Present value of net minimum lease payments under capital leases	$ 22,593

26. RELATED PARTY TRANSACTIONS

Below, we describe significant transactions between us and Westar Industries and some of our other subsidiaries and related parties. We have disclosed these significant transactions even if they have been eliminated in the preparation of our consolidated results and financial position.

ONEOK Shared Services Agreement

We and ONEOK have shared services agreements in which we provide and bill one another for facilities, utility field work, mobile communications, information technology, customer support, meter reading and bill processing. Payments for these services are based on various hourly charges, negotiated fees and out-of-pocket expenses.

	2003	2002	2001
		(In Thousands)	
Charges to ONEOK	$8,312	$8,357	$8,202
Charges from ONEOK	3,190	3,324	3,279

ONEOK notified us of its decision to terminate portions of this shared services agreement. We expect the termination to occur in September 2004. Major items being terminated include electric service orders, call center functions, bill processing and remittance processing. In addition to joint meter reading, we plan to continue to share some facilities and the mobile communications system.

Protection One Shared Services Agreement

We provide administrative services to Protection One pursuant to service agreements, including accounting, tax, audit, human resources, legal, purchasing and facilities services. Fees for these services are based on various hourly charges, negotiated fees and out-of-pocket expenses. Protection One incurred charges of approximately $4.3 million in 2003, $3.9 million in 2002 and $8.1 million in 2001. We expect these services to be discontinued over a transition period of not more than 12 months.

Payments to Protection One

On March 21, 2003, we paid approximately $1.0 million to Protection One as reimbursement for information technology services provided to us, and related costs incurred, by a subsidiary of Protection One. On March 21, 2003, we also paid approximately $3.6 million to Protection One as reimbursement for aviation services provided by a subsidiary of Protection One and for the repurchase of our common and preferred stock held by Protection One. The KCC authorized these payments in the March 11, 2003 KCC order, as described in Note 3.

In June 2003, Westar Industries paid $0.5 million to Protection One for the trademark associated with Protection One Europe as required due to the sale by Westar Industries of Protection One Europe.

Protection One Credit Facility

Westar Industries was the lender under Protection One's senior credit facility. As of December 31, 2003, the outstanding balance of the credit facility was $215.5 million. This facility was assigned to Quadrangle in connection with the sale of our interest in Protection One that was completed on February 17, 2004. At closing, the facility had a balance of $215.5 million.

Financial Advisory Services

Protection One entered into an agreement pursuant to which it paid a quarterly fee to Westar Industries for financial advisory services equal to 0.125% of its consolidated total assets at the end of each quarter. This agreement was approved by the independent members of Protection One's board of directors. Protection One incurred approximately $3.6 million of such fees during the year ended December 31, 2002. This agreement was terminated effective September 30, 2002.

Tax Sharing Agreement

Protection One has been part of our consolidated tax group since 1997. During that time, we have reimbursed Protection One for current tax benefits attributable to Protection One used in our consolidated tax return under the terms of a tax sharing agreement. Following the sale of our Protection One common stock interests on February 17, 2004, Protection One is no longer a part of our consolidated tax group. We and Protection One did not formally terminate our tax sharing agreement and, based on discussions with Protection One and its counsel, there are several areas of potential dispute between us regarding our obligations under the terms of the tax sharing agreement. The most material of these potential disputes involve the proper treatment under the tax sharing agreement of tax obligations or benefits arising out of the transaction in which we sold our interest in Protection One. These items are further discussed in Note 5, "Discontinued Operations — Sale of Protection One and Protection One Europe." The tax sharing payment we owe Protection One for the tax year 2002 and prior tax years is estimated to be $31.7 million. In 2003, we paid $20.0 million to Protection One as authorized by the KCC for 2002. In addition, we may owe additional amounts for amounts that accrued through February 17, 2004, the closing date for the Protection One sale.

Purchase of Stock from Protection One

We purchased 850,000 shares of our common stock and approximately 34,000 shares of our preferred stock from Protection One for approximately $11.6 million in 2003. This transaction was approved by the KCC. The repurchase of common stock was $3.4 million less than what Protection One originally paid.

Transactions Between Westar Energy and KGE

Westar Energy performs KGE’s cash management function, including cash receipts and disbursements. We use an intercompany account to record net receipts and disbursements between Westar Energy and KGE and between KGE and WR Receivables Corporation. KGE’s net amount payable to affiliates was approximately $25.9 million at December 31, 2003 and $24.1 million at December 31, 2002. These intercompany charges have been eliminated in consolidation.

Westar Energy provides all employees used by KGE and allocates certain operating expenses to KGE. These expenses are allocated, depending on the nature of the expense, based on allocation studies, net investment, number of customers and/or other appropriate factors.

Transactions Between Protection One and KGE

During the fourth quarter of 2001, KGE entered into an option agreement to sell an office building located in downtown Wichita, Kansas, to Protection One for approximately $0.5 million. The sales price was determined by management based on three independent appraisers’ findings. This transaction was completed during June 2002. We recognized a loss of $2.6 million on this transaction, and we expected to realize annual operating cost savings of approximately $0.9 million. The cost savings are recorded as a regulatory liability in accordance with a March 26, 2002, KCC order for consideration in a future rate proceeding. For the year ended December 31, 2003, we recorded $1.0 million in cost savings as a regulatory liability and for the year ended December 31, 2002, we recorded $0.5 million in cost savings as a regulatory liability.

Loans to Officers

During 2001 and 2002, we extended loans to our officers for the purpose of purchasing shares of our common stock. The balance outstanding at December 31, 2003 was approximately $2,000, which consisted of accrued interest. For the year ended December 31, 2003, we recorded approximately $35,000 in interest income on these loans. We eliminated this program and no additional loans have been made since the enactment of federal legislation that became effective July 30, 2002.

27. WORK FORCE REDUCTIONS

2001 Involuntary Separation

In late 2001, we reduced our utility work force by approximately 200 employees through involuntary separations. Below is a schedule of the severance payments incurred related to this workforce reduction.

	Year Ended December 31,		
	2003	2002	2001
		(In Thousands)	
Balance at January 1	$—	$ 8,099	$ —
Additions	—	—	12,441
Payments	—	(8,099)	(4,342)
Balance at December 31	$—	$ —	$ 8,099

2002 Voluntary Separation

During 2002, we further reduced our utility work force by approximately 400 employees through a voluntary separation program. We have replaced and may continue to replace some of these employees. Below is a schedule of severance payments incurred related to this workforce reduction.

	Year Ended December 31,		
	2003	2002	2001
	(In Thousands)		
Balance at January 1	$—	$ —	$—
Additions	—	19,496	—
Payments	—	(19,496)	—
Balance at December 31	$—	$ —	$—

Any work force reductions since the completion of the 2002 voluntary separation have been in the normal course of operations.

28. SALE OF UTILITY ASSETS

In August 2003, we sold a portion of our transmission and distribution assets and rights to provide service to approximately 10,000 customers in an area of central Kansas. Total sales proceeds received were $33.3 million and we recorded a gain of $11.9 million, which is included as a reduction in operating and maintenance expenses on our consolidated income statement.

29. SEGMENTS OF BUSINESS

We evaluate segment performance based on earnings per share and have two reportable segments: "Electric Utility" and "Other". We have no single customer from which we receive 10% or more of our revenues.

- "Electric Utility" consists of our integrated electric utility operations, including the generation, transmission and distribution of power to our retail customers in Kansas and to wholesale customers, as well as our energy marketing activities.
- "Other" includes our former ownership interests in ONEOK, Protection One and Protection One Europe and other investments that in the aggregate are immaterial to our business or consolidated results of continuing operations. We expect the "Other" segment will be immaterial in future periods.

	Electric Utility (a)	Other (b)	Total
	(In Thousands, Except Per Share Amounts)		
Year Ended December 31, 2003:			
Sales	$ 1,461,143	$ —	$ 1,461,143
Depreciation and amortization	167,226	10	167,236
Interest expense	193,369	30,987	224,356
Income tax expense	51,050	30,718	81,768
Results of discontinued operations, net of tax	—	(77,905)	(77,905)
Earnings (loss) available for common stock	112,446	(28,404)	84,042
Earnings (loss) per share	1.55	(0.39)	1.16
Additions to property, plant and equipment	150,378	—	150,378
As of December 31, 2003:			
Identifiable assets	$ 4,970,380	$ 764,125	$ 5,734,505

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	Electric Utility (c)	Other (d) (e)	Total
	(In Thousands, Except Per Share Amounts)		
Year Ended December 31, 2002:			
Sales	$1,422,899	$ 252	$1,423,151
Depreciation and amortization	171,749	58	171,807
Interest expense	229,760	5,412	235,172
Income tax expense (benefit)	(5,785)	(5,734)	(11,519)
Results of discontinued operations, net of tax	—	(881,817)	(881,817)
Earnings (loss) available for common stock	19,661	(813,061)	(793,400)
Earnings (loss) per share	0.27	(11.33)	(11.06)
Additions to property, plant and equipment	126,763	—	126,763
As of December 31, 2002:			
Identifiable assets	$5,087,004	$1,653,321	$6,740,325

	Electric Utility	Other (e) (f)	Total
	(In Thousands, Except Per Share Amounts)		
Year Ended December 31, 2001:			
Sales	$1,307,177	$ 1,359	$1,308,536
Depreciation and amortization	185,156	363	185,519
Interest expense (income)	228,129	(12,102)	216,027
Income tax expense (benefit)	(40,018)	13,306	(26,712)
Results of discontinued operations, net of tax	—	(98,903)	(98,903)
Earnings (loss) available for common stock	36,588	(58,359)	(21,771)
Earnings (loss) per share	0.52	(0.83)	(0.31)
Additions to property, plant and equipment	226,996	—	226,996
As of December 31, 2001:			
Identifiable assets	$4,879,641	$2,833,123	$7,712,764

(a) Earnings (loss) per share include a $21.5 million loss related to the putable/callable notes, which includes a loss of $14.2 million associated with the settlement of the call options.
(b) Earnings (loss) per share include investment earnings of $15.7 million of ONEOK preferred dividends, $1.7 million of ONEOK common stock dividends and $99.3 million gain on the sale of ONEOK stock.
(c) Earnings (loss) per share include a $22.9 million reserve for potential liabilities to Mr. Wittig and Mr. Lake and a $22.6 million charge recorded for marking to market changes in the fair value of the call option of the putable/callable notes.
(d) Earnings (loss) per share include investment earnings of $37.1 million of ONEOK preferred dividends.
(e) Sales are from a wholly owned subsidiary of Westar Industries providing paging services, which was sold during the first quarter of 2002.
(f) Earnings (loss) per share include investment earnings of $37.1 million of ONEOK preferred dividends.

Geographic Information

We have operations only in the United States. Our management looks at our operations as a whole and does not segregate according to any operational areas.

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30. QUARTERLY RESULTS (UNAUDITED)

The amounts in the table are unaudited, but in the opinion of management, contain all adjustments (consisting only of normal recurring adjustments) necessary for a fair presentation of the results of such periods. Our electric business is seasonal in nature and, in our opinion, comparisons between the quarters of a year do not give a true indication of overall trends and changes in operations.

	First	Second	Third	Fourth
	(In Thousands, Except Per Share Amounts)			
2003				
Sales	$ 345,434	$ 345,885	$ 438,167	$ 331,657
Income from continuing operations before accounting change and preferred dividends	20,102	21,807	80,584	40,422
Discontinued operations	103,822	6,378	(161,651)	(26,454)
Net income (loss)	123,924	28,185	(81,067)	13,968
Earnings (loss) available for common stock	$ 123,697	$ 27,943	$ (81,283)	$ 13,686
Per Share Data (a):				
Basic:				
Earnings available from continuing operations before accounting change and preferred dividends	$ 0.28	$ 0.30	$ 1.11	$ 0.56
Discontinued operations, net of tax	1.44	0.09	(2.23)	(0.37)
Earnings (loss) available	$ 1.72	$ 0.39	$ (1.12)	$ 0.19
Diluted:				
Earnings available from continuing operations before accounting change and preferred dividends	$ 0.28	$ 0.29	$ 1.09	$ 0.55
Discontinued operations, net of tax	1.43	0.09	(2.20)	(0.36)
Earnings (loss) available	$ 1.71	$ 0.38	$ (1.11)	$ 0.19
Cash dividend per common share	$ 0.19	$ 0.19	$ 0.19	$ 0.19
Market price per common share:				
High	$ 13.04	$ 17.09	$ 18.65	$ 20.49
Low	$ 9.76	$ 12.15	$ 15.45	$ 18.40

(a) Earnings (loss) per share is computed independently for each of the periods presented. The sum of the earnings (loss) per share amounts for the quarters may not equal the total for the year.

	First	Second	Third	Fourth
	(In Thousands, Except Per Share Amounts)			
2002				
Sales	$ 317,239	$ 332,715	$ 442,145	$ 331,052
Income from continuing operations before accounting change and preferred dividends	5,759	8,253	46,722	28,082
Discontinued operations	(752,285)	1,021	(3,155)	(127,398)
Net income (loss)	(746,526)	9,275	43,567	(99,317)
Earnings (loss) available for common stock	$ (746,310)	$ 9,172	$ 43,301	$ (99,563)
Per Share Data (a):				
Basic:				
Earnings available from continuing operations before accounting change and preferred dividends	$ 0.08	$ 0.11	$ 0.65	$ 0.39
Discontinued operations, net of tax	(10.54)	0.02	(0.04)	(1.78)
Earnings (loss) available	$ (10.46)	$ 0.13	$ 0.61	$ (1.39)
Diluted:				
Earnings available from continuing operations before accounting change and preferred dividends	$ 0.08	$ 0.11	$ 0.64	$ 0.39
Discontinued operations, net of tax	(10.54)	0.02	(0.04)	(1.76)
Earnings (loss) available	$ (10.46)	$ 0.13	$ 0.60	$ (1.37)
Cash dividend per common share	$ 0.30	$ 0.30	$ 0.30	$ 0.30
Market price per common share:				
High	$ 18.00	$ 17.80	$ 16.00	$ 12.02
Low	$ 15.79	$ 14.25	$ 9.44	$ 8.50

(a) Earnings (loss) per share is computed independently for each of the periods presented. The sum of the earnings (loss) per share amounts for the quarters may not equal the total for the year.

31. SUBSEQUENT EVENT

In February 2004, we repaid the remaining balance of $114.1 million under our $585.0 million term loan that was due in 2005 with internally generated cash and a portion of the proceeds received from the sale of Protection One.

32. RESTATEMENT OF CASH FLOW STATEMENTS

Subsequent to the issuance of the December 31, 2003 financial statements, we determined that certain components in our consolidated statements of cash flows for 2003, 2002 and 2001 were incorrectly classified. The misstatements related to classification within the cash flow statements of cash distributions received from investments in foreign power projects, the reinvestment of dividends payable on shares of our common stock issued or reissued under our Direct Stock Purchase Plan and other individually insignificant items as either cash flow from investing activities or financing activities. As a result, the accompanying statements of cash flows for the years ended December 31, 2003, 2002 and 2001 have been restated from the amounts previously reported to increase cash flows from operating activities by $10.2 million, $39.2 million and $13.5 million for 2003, 2002 and 2001, respectively, to decrease cash flows from investing activities by $10.2 million and $21.1 million for 2003 and 2002, respectively, and increase cash flow from investing activities for 2001 by $6.6 million. Cash flow from financing activities for 2002 and 2001 decreased by $18.1 million and $20.1 million, respectively.

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ONEOK, INC.

INDEX TO FINANCIAL STATEMENTS

Independent Auditors' Report together with the audited consolidated balance sheets of ONEOK, Inc. and subsidiaries as of December 31, 2003 and December 31, 2002 and the related consolidated statements of income, shareholders' equity and comprehensive income and cash flows for each of the years in the three-year period ended December 31, 2003.

All financial information concerning ONEOK was excerpted from the reports it files with the SEC pursuant to the Securities Exchange Act. We have not independently verified the information concerning ONEOK contained in this filing and we do not make any representation or warranty concerning the accuracy thereof.

INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Shareholders
ONEOK, Inc.:

We have audited the accompanying consolidated balance sheets of ONEOK, Inc. and subsidiaries as of December 31, 2003 and 2002 and the related consolidated statements of income, shareholders' equity and comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2003. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. 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 ONEOK, Inc. and subsidiaries as of December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Notes A and F to the consolidated financial statements, the Company adopted the provisions of Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations, the recognition and measurement principles of Statement of Financial Accounting Standards No. 123, Accounting for Stock-Based Compensation, and the rescission of the provisions of Emerging Issues Task Force 98-10, Accounting for Contracts Involved in Energy Trading and Risk Management Activities, effective January 1, 2003, the provisions of Statement of Financial Accounting Standards No. 142, Goodwill and Other Intangible Assets, effective January 1, 2002 and the provisions of Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities, effective January 1, 2001.

KPMG LLP

Tulsa, Oklahoma
February 13, 2004

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ONEOK, Inc. and Subsidiaries
CONSOLIDATED STATEMENTS OF INCOME

	Years Ended December 31,		
	2003	**2002**	**2001**
	(Thousands of Dollars, except per share amounts)		
Revenues			
Operating revenues, excluding energy trading revenues	**$ 2,769,214**	$ 1,894,851	$ 1,814,180
Energy trading revenues, net	**229,782**	209,429	101,761
Cost of gas	**1,862,518**	1,128,620	1,089,566
Net Revenues	**1,136,478**	975,660	826,375
Operating Expenses			
Operations and maintenance	**463,116**	401,328	381,589
Depreciation, depletion, and amortization	**160,861**	147,843	133,533
General taxes	**66,437**	55,011	55,644
Total Operating Expenses	**690,414**	604,182	570,766
Operating Income	**446,064**	371,478	255,609
Other income	**8,164**	12,426	9,852
Other expense	**5,224**	19,038	8,976
Interest expense	**104,185**	106,405	140,158
Income before Income Taxes	**344,819**	258,461	116,327
Income taxes	**130,527**	102,485	37,490
Income from Continuing Operations	**214,292**	155,976	78,837
Discontinued operations, net of taxes *(Note C):*			
Income from operations of discontinued component	**2,342**	10,648	24,879
Gain on sale of discontinued component	**39,739**	—	—
Cumulative effect of changes in accounting principles, net of tax *(Note A and D)*	**(143,885)**	—	(2,151)
Net Income	**112,488**	166,624	101,565
Preferred stock dividends	**24,211**	37,100	37,100
Income Available for Common Stock	**$ 88,277**	$ 129,524	$ 64,465
Earnings Per Share of Common Stock *(Note S)*			
Basic:			
Earnings per share from continuing operations	**$ 2.38**	$ 1.31	$ 0.66
Earnings per share from operations of discontinued component	**0.02**	0.09	0.21
Earnings per share from gain on sale of discontinued component	**0.36**	—	—
Earnings per share from cumulative effect of changes in accounting principle	**(1.28)**	—	(0.02)
Net earnings per share, basic	**$ 1.48**	$ 1.40	$ 0.85
Diluted:			
Earnings per share from continuing operations	**2.13**	$ 1.30	$ 0.66
Earnings per share from operations of discontinued component	**0.02**	0.09	0.21
Earnings per share from gain on sale of discontinued component	**0.35**	—	—
Earnings per share from cumulative effect of changes in accounting principle	**(1.28)**	—	(0.02)
Net earnings per share, diluted	**$ 1.22**	$ 1.39	$ 0.85
Average Shares of Common Stock *(Thousands)*			
Basic	**80,569**	99,914	99,449
Diluted	**96,999**	100,528	99,671
Dividends per share of Common Stock	**$ 0.69**	$ 0.62	$ 0.62

See accompanying Notes to Consolidated Financial Statements.

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ONEOK, Inc. and Subsidiaries
CONSOLIDATED BALANCE SHEETS

	December 31, 2003	December 31, 2002
	(Thousands of Dollars)	
Assets		
Current Assets		
Cash and cash equivalents	**$ 12,172**	$ 73,522
Trade accounts and notes receivable, net	**970,141**	773,017
Materials and supplies	**18,962**	16,949
Gas in storage	**500,439**	58,544
Unrecovered purchased gas costs	**—**	3,576
Assets from price risk management activities *(Note D)*	**289,417**	724,842
Deposits	**42,424**	—
Other current assets	**46,184**	44,790
Assets of discontinued component *(Note C)*	**—**	276
Total Current Assets	**1,879,739**	1,695,516
Property, Plant and Equipment		
Production	**404,254**	144,174
Gathering and Processing	**1,036,080**	993,504
Transportation and Storage	**699,676**	689,150
Distribution	**2,813,800**	2,169,382
Marketing and Trading	**126,315**	124,512
Other	**99,549**	94,778
Total Property, Plant and Equipment	**5,179,674**	4,215,500
Accumulated depreciation, depletion, and amortization	**1,487,848**	1,199,568
Net Property, Plant and Equipment	**3,691,826**	3,015,932
Deferred Charges and Other Assets		
Regulatory assets, net *(Note E)*	**213,915**	217,978
Goodwill *(Note F)*	**225,615**	113,510
Assets from price risk management activities *(Note D)*	**113,052**	360,645
Prepaid pensions	**120,618**	125,426
Investments and other	**69,283**	55,526
Total Deferred Charges and Other Assets	**742,483**	873,085
Non-current Assets of Discontinued Component *(Note C)*	**—**	225,061
Total Assets	**$ 6,314,048**	$ 5,809,594

See accompanying Notes to Consolidated Financial Statements.

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ONEOK, Inc. and Subsidiaries
CONSOLIDATED BALANCE SHEETS

	December 31, 2003	December 31, 2002
	(Thousands of Dollars)	
Liabilities and Shareholders' Equity		
Current Liabilities		
Current maturities of long-term debt	**$ 6,334**	$ 6,334
Notes payable	**600,000**	265,500
Accounts payable	**813,895**	672,153
Accrued taxes	**102,637**	41,922
Accrued interest	**32,999**	29,202
Customers' deposits	**34,692**	21,096
Unrecovered purchased gas costs	**51,378**	—
Liabilities from price risk management activities *(Note D)*	**302,878**	496,467
Deferred income taxes	**150,816**	130,328
Other	**130,174**	125,129
Liabilities of discontinued component *(Note C)*	**—**	1,445
Total Current Liabilities	**2,225,803**	1,789,576
Long-term Debt, excluding current maturities	**1,878,264**	1,511,118
Deferred Credits and Other Liabilities		
Deferred income taxes	**414,734**	475,163
Liabilities from price risk management activities *(Note D)*	**112,714**	309,070
Lease obligation	**100,292**	109,051
Other deferred credits	**340,849**	208,989
Total Deferred Credits and Other Liabilities	**968,589**	1,102,273
Non-current Liabilities of Discontinued Component *(Note C)*	**—**	41,015
Total Liabilities	**5,072,656**	4,443,982
Commitments and Contingencies *(Note M)*		
Shareholders' Equity		
Convertible Preferred Stock, $0.01 par value:		
Series A authorized 20,000,000 shares; issued and outstanding 19,946,448 shares at December 31, 2002	**—**	199
Common stock, $0.01 par value:		
authorized 300,000,000 shares; issued 98,194,674 shares and outstanding 95,194,666 shares at December 31, 2003; issued 63,438,441 shares and outstanding 60,761,064 shares at December 31, 2002	**982**	634
Paid in capital *(Note I)*	**815,870**	903,918
Unearned compensation	**(3,422)**	(2,716)
Accumulated other comprehensive loss *(Note G)*	**(17,626)**	(5,546)
Retained earnings	**495,971**	507,836
Treasury stock, at cost: 3,000,008 shares at December 31, 2003 and 2,677,377 shares at December 31, 2002	**(50,383)**	(38,713)
Total Shareholders' Equity	**1,241,392**	1,365,612
Total Liabilities and Shareholders' Equity	**$ 6,314,048**	$ 5,809,594

See accompanying Notes to Consolidated Financial Statements.

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ONEOK, Inc. and Subsidiaries
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2003	**2002**	**2001**
		(Thousands of Dollars)	
Operating Activities			
Income from continuing operations	**$ 214,292**	$ 155,976	$ 78,837
Depreciation, depletion, and amortization	**160,861**	147,843	133,533
Gain on sale of assets	**292**	(1,213)	(1,120)
Gain on sale of equity investments	**—**	(7,622)	(758)
Income from equity investments	**(1,547)**	(366)	(8,109)
Deferred income taxes	**111,788**	165,723	120,189
Stock based compensation expense	**6,289**	2,121	1,110
Allowance for doubtful accounts	**14,073**	12,478	43,495
Changes in assets and liabilities (net of acquisition effects):			
Accounts and notes receivable	**(156,887)**	(122,733)	909,284
Inventories	**(428,408)**	27,334	(11,854)
Unrecovered purchased gas costs	**54,954**	41,522	(43,520)
Deposits	**(42,424)**	41,781	79,019
Regulatory assets	**(13,467)**	(543)	(8,387)
Accounts payable and accrued liabilities	**100,961**	239,167	(701,153)
Price risk management assets and liabilities	**27,651**	(19,038)	(198,611)
Other assets and liabilities	**(52,631)**	86,062	(49,992)
Cash Provided by (Used in) Continuing Operations	**(4,203)**	768,492	341,963
Cash Provided by Discontinued Operations	**8,285**	43,789	63,388
Cash Provided by Operating Activities	**4,082**	812,281	405,351
Investing Activities			
Changes in other investments, net	**(1,126)**	2,015	981
Acquisitions	**(690,302)**	(4,036)	(14,940)
Capital expenditures	**(215,148)**	(210,652)	(306,022)
Proceeds from sale of property	**3,084**	102,390	7,911
Proceeds from sale of equity investment	**—**	57,461	7,425
Cash Used in Continuing Operations	**(903,492)**	(52,822)	(304,645)
Cash Provided by (Used in) Discontinued Operations	**280,669**	(22,393)	(36,407)
Cash Used in Investing Activities	**(622,823)**	(75,215)	(341,052)
Financing Activities			
Borrowing (payments) of notes payable, net	**334,500**	(333,606)	(225,000)
Change in bank overdraft	**20,574**	14,584	(141,923)
Issuance of debt	**404,964**	3,500	401,367
Payment of debt issuance costs	**(2,564)**	—	—
Payment of debt	**(16,148)**	(305,623)	(7,583)
Purchase of Series A Convertible Preferred Stock	**(300,000)**	—	—
Purchase of common stock	**(50,000)**	—	—
Issuance of common stock	**224,412**	—	5,447
Issuance of treasury stock, net	**12,616**	3,673	5,214
Dividends paid	**(70,963)**	(74,301)	(73,841)
Cash Provided by (Used in) Financing Activities	**557,391**	(691,773)	(36,319)
Change in Cash and Cash Equivalents	**(61,350)**	45,293	27,980
Cash and Cash Equivalents at Beginning of Period	**73,522**	28,229	249
Cash and Cash Equivalents at End of Period	**$ 12,172**	$ 73,522	$ 28,229

See accompanying Notes to Consolidated Financial Statements.

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ONEOK, Inc. and Subsidiaries
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME

	Common Stock Issued	Preferred Stock Issued	Series A Convertible Preferred Stock	Series D Convertible Preferred Stock	Common Stock	Paid-in Capital
	(Shares)			*(Thousands of Dollars)*		
December 31, 2000	31,599,305	19,946,448	$199	$ —	$316	$895,668
Net income	—	—	—	—	—	—
Other comprehensive income	—	—	—	—	—	—
Total comprehensive income						
Effect of two-for-one stock split	31,718,017	—	—	—	317	(317)
Re-issuance of treasury stock	—	—	—	—	—	866
Issuance of common stock						
Stock purchase plans	121,119	—	—	—	1	5,317
Convertible preferred stock dividends - $1.86 per share for Series A	—	—	—	—	—	—
Acquisition of treasury stock	—	—	—	—	—	—
Issuance of restricted stock	—	—	—	—	—	715
Amortization of restricted stock	—	—	—	—	—	—
Forfeitures of restricted stock	—	—	—	—	—	20
Common stock dividends - $0.62 per share	—	—	—	—	—	—
December 31, 2001	63,438,441	19,946,448	$199	$ —	$634	$902,269
Net income	—	—	—	—	—	—
Other comprehensive income	—	—	—	—	—	—
Total comprehensive income						
Re-issuance of treasury stock	—	—	—	—	—	633
Issuance of common stock						
Stock purchase plans	—	—	—	—	—	614
Convertible preferred stock dividends - $1.86 per share for Series A	—	—	—	—	—	—
Acquisition of treasury stock	—	—	—	—	—	—
Issuance of restricted stock	—	—	—	—	—	410
Amortization of restricted stock	—	—	—	—	—	—
Forfeitures of restricted stock	—	—	—	—	—	(8)
Shares retained for taxes due on vested restricted stock	—	—	—	—	—	—
Common stock dividends - $0.62 per share	—	—	—	—	—	—
December 31, 2002	63,438,441	19,946,448	$199	$ —	$634	$903,918

See accompanying Notes to Consolidated Financial Statements.

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ONEOK, Inc. and Subsidiaries
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME
(Continued)

	Unearned Compensation	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Treasury Stock	Total
			(Thousands of Dollars)		
December 31, 2000	$(1,128)	$ —	$387,789	$(57,887)	$1,224,957
Net income	—	—	101,565	—	101,565
Other comprehensive income	—	(1,780)	—	—	(1,780)
Total comprehensive income					99,785
Effect of two-for-one stock split	—	—	—	—	—
Re-issuance of treasury stock	—	—	—	7,278	8,144
Issuance of common stock					
Stock purchase plans	—	—	—	—	5,318
Convertible preferred stock dividends - $1.86 per share for Series A	—	—	(37,100)	—	(37,100)
Acquisition of treasury stock	—	—	—	(29)	(29)
Issuance of restricted stock	(1,932)	—	—	1,217	—
Amortization of restricted stock	1,110	—	—	—	1,110
Forfeitures of restricted stock	78	—	—	(124)	(26)
Common stock dividends - $0.62 per share	(128)	—	(36,741)	—	(36,869)
December 31, 2001	$(2,000)	$(1,780)	$415,513	$(49,545)	$1,265,290
Net income	—	—	166,624	—	166,624
Other comprehensive income	—	(3,766)	—	—	(3,766)
Total comprehensive income					162,858
Re-issuance of treasury stock	—	—	—	4,926	5,559
Issuance of common stock					
Stock purchase plans	—	—	—	4,201	4,815
Convertible preferred stock dividends - $1.86 per share for Series A	—	—	(37,100)	—	(37,100)
Acquisition of treasury stock	—	—	—	(5)	(5)
Issuance of restricted stock	(2,664)	—	—	2,254	—
Amortization of restricted stock	2,121	—	—	—	2,121
Forfeitures of restricted stock	36	—	—	(28)	—
Shares retained for taxes due on vested restricted stock	—	—	—	(516)	(516)
Common stock dividends - $0.62 per share	(209)	—	(37,201)	—	(37,410)
December 31, 2002	$(2,716)	$(5,546)	$507,836	$(38,713)	$1,365,612

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ONEOK, Inc. and Subsidiaries
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME

	Common Stock Issued	Preferred Stock Issued	Series A Convertible Preferred Stock	Series D Convertible Preferred Stock	Common Stock	Paid-in Capital
	(Shares)			*(Thousands of Dollars)*		
December 31, 2002	63,438,441	19,946,448	$199	$ —	$634	$903,918
Net income	—	—	—	—	—	—
Other comprehensive income	—	—	—	—	—	—
Total comprehensive income						
Re-issuance of treasury stock		—	—	—	—	1,608
Issuance of common stock						
Common stock offering	13,800,000	—	—	—	138	227,893
Stock issuance pursuant to various plans	—	—	—	—	—	6,029
Issuance costs of equity units	—	—	—	—	—	(9,728)
Contract adjustment payment	—	—	—	—	—	(50,805)
Repurchase of Series A Convertible Preferred Stock	18,077,511	(9,038,755)	(90)	—	181	(91)
Exchange of Series A Convertible Preferred Stock	—	(10,907,693)	(109)	—	—	(308,466)
Issuance of Series D Convertible Preferred Stock	—	21,815,386	—	218	—	361,747
Repurchase of common stock	—	—	—	—	—	—
Exchange of Series D Convertible Preferred Stock	—	(8,418,000)	—	(84)	—	(137,551)
Conversion of Series D Convertible Preferred Stock	2,551,835	(13,397,386)	—	(134)	26	(182,035)
Issuance of restricted stock	—	—	—	—	—	107
Forfeiture of restricted stock	—	—	—	—	—	—
Registration Costs	—	—	—	—	—	(268)
Stock-based employee compensation expense	326,887	—	—	—	3	3,512
Convertible preferred stock dividends	—	—	—	—	—	—
Common stock dividends–$0.69 per share	—	—	—	—	—	—
December 31, 2003	98,194,674	—	$ —	$ —	$982	$815,870

See accompanying Notes to Consolidated Financial Statements.

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ONEOK, Inc. and Subsidiaries
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME
(Continued)

	Unearned Compensation	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Treasury Stock	Total
			(Thousands of Dollars)		
December 31, 2002	$(2,716)	$ (5,546)	$507,836	$(38,713)	$1,365,612
Net income	—	—	112,488	—	112,488
Other comprehensive income	—	(12,080)	—	—	(12,080)
Total comprehensive income					100,408
Re-issuance of treasury stock	—	—	—	15,458	17,066
Issuance of common stock					
Common stock offering	—	—	—	—	228,031
Stock issuance pursuant to various plans	—	—	—	—	6,029
Issuance costs of equity units	—	—	—	—	(9,728)
Contract adjustment payment	—	—	—	—	(50,805)
Repurchase of Series A Convertible Preferred Stock	—	—	—	(300,000)	(300,000)
Exchange of Series A Convertible Preferred Stock	—	—	—	—	(308,575)
Issuance of Series D Convertible Preferred Stock	—	—	(53,390)	—	308,575
Repurchase of common stock	—	—	—	(50,000)	(50,000)
Exchange of Series D Convertible Preferred Stock	—	—	—	137,635	—
Conversion of Series D Convertible Preferred Stock	—	—	—	182,143	—
Issuance of restricted stock	(3,206)	—	—	3,099	—
Forfeiture of restricted stock	5	—	—	(5)	—
Registration Costs	—	—	—	—	(268)
Stock-based employee compensation expense	2,774	—	—	—	6,289
Convertible preferred stock dividends	—	—	(18,753)	—	(18,753)
Common stock dividends - $0.69 per share	(279)	—	(52,210)	—	(52,489)
December 31, 2003	$(3,422)	$(17,626)	$495,971	$(50,383)	$1,241,392

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(A) SUMMARY OF ACCOUNTING POLICIES

Nature of Operations - ONEOK, Inc. and subsidiaries (collectively, the "Company" or "ONEOK") is a diversified energy company engaged in the production, processing, gathering, storage, transportation, distribution, and marketing of natural gas, electricity, natural gas liquids and crude oil. The Company manages its business in six segments: Production, Gathering and Processing, Transportation and Storage, Distribution, Marketing and Trading, and Other.

The Production segment produces natural gas and oil and owns natural gas and oil reserves in Oklahoma and Texas. The Company owns and operates gas processing plants, as well as gathering pipelines in Oklahoma, Kansas and Texas through its Gathering and Processing segment. The Transportation and Storage segment owns and leases natural gas storage facilities and transports gas in Oklahoma, Kansas and Texas. The Company's Distribution segment provides natural gas distribution services in Oklahoma, Kansas and Texas through Oklahoma Natural Gas Company (ONG), Kansas Gas Service Company (KGS) and Texas Gas Service Company (TGS), respectively. The Marketing and Trading segment markets natural gas to wholesale and retail customers and markets electricity to wholesale customers. The Company's Other segment, whose results of operations are not material, operates and leases the Company's headquarters building and parking facility.

Critical Accounting Policies

Energy Trading Derivatives and Risk Management Activities - The Company engages in wholesale marketing and trading, price risk management activities and asset optimization services. In providing asset optimization services, the Company partners with other utilities to provide risk management functions on their behalf. The Company accounts for derivative instruments utilized in connection with these activities under the fair value basis of accounting in accordance with the Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" (Statement 133) as amended by Statement of Financial Accounting Standards No. 137, "Accounting for Derivative Instruments and Hedging Activities—Deferral of the Effective Date of FASB Statement No. 133" (Statement 137), No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities" (Statement 138) and No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" (Statement 149). Statement 149 had no impact on the Company.

Under Statement 133, entities are required to record all derivative instruments in price risk management assets and liabilities at fair value. The fair value of derivative instruments is determined by commodity exchange prices, over-the-counter quotes, volatility, time value, counterparty credit and the potential impact on market prices of liquidating positions in an orderly manner over a reasonable period of time under current market conditions. The majority of the Company's portfolio is based on actual market prices while only a small part is subject to estimate. The Company's derivative instruments are highly concentrated in liquid markets, thereby providing a short life for these instruments. Market value changes result in a change in the fair value of the Company's derivative instruments. The gain or loss from this change in fair value is recorded in the period of the change. The volatility of commodity prices may have a significant impact on the gain or loss in any given period. The gains and losses resulting from changes in fair value are accounted for in accordance with Statement 133. See Note D.

Energy-related contracts that are not accounted for pursuant to Statement 133 are no longer carried at fair value, but are accounted for on an accrual basis as executory contracts. Energy trading inventories carried under storage agreements are no longer carried at fair value, but are carried at the lower of cost or market. Changes to the accounting for existing contracts as a result of the rescission of Emerging Issues Task Force Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities" (EITF 98-10) were reported as a cumulative effect of a change in accounting principle on January 1, 2003. This resulted in a cumulative effect loss, net of tax, of $141.8 million.

Regulation - The Company's intrastate transmission pipelines and distribution operations are subject to the rate regulation and accounting requirements of the Oklahoma Corporation Commission (OCC), Kansas Corporation Commission (KCC), Texas Railroad Commission (TRC) and various municipalities in Texas. Certain other transportation activities of the Company are subject to regulation by the Federal Energy Regulatory Commission (FERC). ONG, KGS, TGS and portions of the Transportation and Storage segment follow the accounting and reporting guidance contained in Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation" (Statement 71). During the rate-making process, regulatory authorities may require a utility to defer recognition of certain costs to be recovered through rates over time as opposed to expensing such costs as incurred. This allows the utility to stabilize rates over time rather than passing such costs on to the customer for immediate recovery. Accordingly, actions of the regulatory authorities could have an affect on the amount recovered from rate payers. Any difference in the amount recoverable and the amount deferred would be recorded as income or expense at the time of the regulatory action. If all or a portion of the regulated operations becomes no longer subject to the provision of Statement 71, a write-off of regulatory assets and stranded costs may be required. At December 31, 2003, the Company's regulatory assets totaled $213.9 million.

Impairment of Goodwill and Long-Lived Assets - The Company assess its goodwill for impairment at least annually based on Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets" (Statement 142). An initial assessment is made by comparing the fair value of the operations with goodwill, as determined in accordance with Statement 142, to the book value. If the fair value is less than the book value, an impairment is indicated and the Company must perform a second test to measure the amount of the impairment. In the second test, the Company calculates the implied fair value of the goodwill by deducting the fair value of all tangible and intangible net assets of the operations with goodwill from the fair value determined in step one of the assessment. If the carrying value of the goodwill exceeds this calculated implied fair value of the goodwill, an impairment charge is recorded. See Note F.

The Company assesses its long-lived assets for impairment based on Statement of Financial Accounting Standards No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (Statement 144). A long-lived asset is tested for impairment whenever events or changes in circumstances indicate that its carrying amount may exceed its fair value. Fair values are based on sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the assets.

Examples of long-lived asset impairment indicators include:

- significant and long-term declines in commodity prices
- a major accident affecting the use of an asset
- part or all of a regulated business no longer operating under Statement 71
- a significant decrease in the rate of return for a regulated business

Pension and Postretirement Employee Benefits - The Company has a defined pension plan covering substantially all full-time employees and a postretirement employee benefits plan covering most employees. The Company's actuarial consultant, in calculating the expense and liability related to these plans, uses statistical and other factors that attempt to anticipate future events. These factors include assumptions about the discount rate, expected return on plan assets, rate of future compensation increases, age and employment periods. In determining the projected benefit obligations and the costs, assumptions can change from period to period and result in material changes in the costs and liabilities recognized by the Company. See Note L.

Contingencies - The Company's accounting for contingencies covers a variety of business activities including contingencies for potentially uncollectible receivables, legal exposures and environmental exposures. The Company accrues these contingencies when its assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered and an amount can be reasonably estimated in accordance with Statement of Financial Accounting Standards No. 5, "Accounting for Contingencies". The Company bases its estimates on currently available facts and its estimates of the ultimate outcome or resolution. Actual results may differ from the Company's estimates resulting in an impact, either positive or negative, on earnings.

Significant Accounting Policies

Consolidation - The consolidated financial statements include the accounts of ONEOK, Inc. and its wholly-owned subsidiaries. All significant intercompany accounts and transactions have been eliminated in consolidation. Investments in 20 percent to 50 percent-owned affiliates are accounted for on the equity method. Investments in less than 20 percent owned affiliates are accounted for on the cost method.

Cash and Cash Equivalents - Cash equivalents consist of highly liquid investments, which are readily convertible into cash and have original maturities of three months or less.

Inventories - Materials and supplies are valued at average cost. Noncurrent gas in storage is classified as property and is valued at cost. The Marketing and Trading segment's gas in storage of $223.8 million, which was recorded in current price risk management assets, was carried at fair value at December 31, 2002. At December 31, 2003, the Marketing and Trading segment's gas in storage of $328.8 million was carried at the lower of cost or market and is recorded in gas in storage in the balance sheet. This change was the result of the rescission of EITF 98-10. Cost of current gas in storage for ONG is determined under the last-in, first-out (LIFO) methodology. The estimated replacement cost of current gas in storage was $28.3 million and $2.5 million at December 31, 2003 and 2002, respectively, compared to its value under the LIFO method of $32.6 million and $2.3 million at December 31, 2003 and 2002, respectively. Current gas and NGLs in storage for all other companies is determined using the weighted average cost of gas method.

Non-Trading Derivative Instruments and Hedging Activities - To minimize the risk of fluctuations in natural gas and crude oil prices, the Company's nontrading segments periodically enter into futures transactions, swaps, and options in order to hedge anticipated sales of natural gas and crude oil production, fuel requirements and NGL inventories. Interest rate swaps are also used to manage interest rate risk.

On January 1, 2001, the Company adopted the provisions of Statement 133, amended by Statement 137, Statement 138 and Statement 149. Statement 149 had no impact on the Company. Many of the Company's purchase and sale agreement that otherwise would be required to follow derivative accounting qualify as normal purchases and normal sales under Statement 133 and are therefore exempt from fair value accounting treatment.

Regulated Property - Regulated properties are stated at cost, which includes an allowance for funds used during construction. The allowance for funds used during construction represents the capitalization of the estimated average cost of borrowed funds (6.4 percent in 2003 and 2002, respectively) used during the construction of major projects and is recorded as a credit to interest expense.

Depreciation is calculated using the straight-line method based on rates prescribed for ratemaking purposes. The average depreciation rate for property that is regulated by the OCC approximated 2.8 percent, 3.0 percent and 2.9 percent in fiscal years 2003, 2002 and 2001, respectively. The average depreciation rate for property that is regulated by the KCC approximated 3.3 percent, 3.4 percent and 3.4 percent in fiscal years 2003, 2002 and 2001, respectively. The average depreciation rate for property that is regulated by the TRC and various municipalities in Texas approximated 3.2 percent in fiscal year 2003. The average depreciation rates for Mid Continent Market Center, Inc. (MCMC) properties were 3.5 percent, 3.6 percent and 3.4 percent in fiscal years 2003, 2002 and 2001, respectively.

Maintenance and repairs are charged directly to expense. Generally, the cost of property retired or sold, plus removal costs, less salvage, is charged to accumulated depreciation. Gains and losses from sales or transfers of operating units or systems are recognized in income.

The following table sets forth the remaining life and service years of the Company's regulated properties.

	Remaining Life	Service Years
Distribution property	18-24	34-45
Transmission property	9-34	31-40
Other property	6-20	16-25

Production Property - The Company uses the successful-efforts method to account for costs incurred in the acquisition and development of natural gas and oil reserves. Costs to acquire mineral interests in proved reserves and to drill and equip development wells are capitalized. Geological and geophysical costs and costs to drill exploratory wells which do not find proved reserves are expensed. Unproved oil and gas properties, which are individually significant, are periodically assessed for impairment. The remaining unproved oil and gas properties are aggregated and amortized based upon remaining lease terms and exploratory and developmental drilling experience. Depreciation and depletion are calculated using the unit-of-production method based upon periodic estimates of proved oil and gas reserves.

The FASB is expected to consider, based on a Securities and Exchange Commission (SEC) request, whether or not acquired oil and gas drilling rights should be classified as an intangible asset pursuant to Statement of Financial Accounting Standards No. 141, "Business Combinations" (Statement 141) and Statement 142. The Company classifies the cost of oil and gas mineral rights as property, plant, and equipment on the balance sheet and believes this classification is consistent with oil and gas accounting and industry practice. If the FASB determines that oil and gas drilling rights acquired are intangible assets pursuant to Statement 141 and Statement 142, approximately $271.8 million and $70.7 million would be reclassified from property, plant, and equipment to intangible assets on the December 31, 2003 and 2002 balance sheet, respectively. The reclassification would have no effect on the statements of income or cash flows. This reclassification to intangible assets would require additional disclosures under accounting standards.

Other Property - Gas processing plants and all other properties are stated at cost. Gas processing plants are depreciated using various rates based on estimated lives of available gas reserves. All other property and equipment is depreciated using the straight-line method over its estimated useful life.

Environmental Expenditures - The Company accrues for losses associated with environmental remediation obligations when such losses are probable and reasonably estimable. Accruals for estimated losses from environmental remediation obligations generally are recognized no later than completion of the remedial feasibility study. Such accruals are adjusted as further information becomes available or circumstances change. Recoveries of environmental remediation costs from other parties are recorded as assets when their receipt is deemed probable.

Revenue Recognition - Revenues from the Production segment are recognized on the sales method when oil and gas production volumes are delivered to the purchaser.

The Company's remaining segments recognize revenue when services are rendered or product is delivered. Major industrial and commercial gas distribution customers are invoiced as of the end of each month. Certain gas distribution customers, primarily residential and some commercial are invoiced on a cycle basis throughout the month, and the Company accrues unbilled revenues at the end of each month. ONG's, KGS' and TGS' tariff rates for residential and commercial customers contain a temperature normalization clause that provides for billing adjustments from actual volumes to normalized volumes during the winter heating season. A flat monthly fee is included in TGS' authorized rate design for El Paso and Port Arthur to protect customers from abnormal weather.

Income Taxes - Deferred income taxes are recognized for the tax consequences of temporary differences by applying enacted statutory tax rates applicable to future years to differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities. The effect on deferred taxes of a change in tax rates is deferred and amortized for operations regulated by the OCC, KCC, TRC and the various municipalities that TGS serves. For all other operations the effect is recognized in income in the period that includes the enactment date. The Company continues to amortize previously deferred investment tax credits for ratemaking purposes over the period prescribed by the OCC, KCC, TRC and the various municipalities that TGS serves.

Asset Retirement Obligations - On January 1, 2003, the Company adopted Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (Statement 143). Statement 143 applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the asset.

Statement 143 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 the fair value can be made. The fair value of the liability is added to the carrying amount of the associated asset and this additional carrying amount is depreciated over the life of the asset. The liability is accreted at the end of each period through charges to operating expense. If the obligation is settled for an amount other than the carrying amount of the liability, the Company will recognize a gain or loss on settlement.

All legal obligations for asset retirement obligations were identified and the fair value of these obligations was determined as of January 1, 2003. The obligations primarily relate to the 300-megawatt power plant and various processing plants, storage facilities and producing wells. As a result of the adoption of Statement 143, the Company recorded a long-term liability of approximately $16.3 million, an increase to property, plant and equipment, net of accumulated depreciation, of approximately $12.9 million, and a cumulative effect charge of approximately $2.1 million, net of tax, in the first quarter of 2003. The related depreciation and amortization expense is immaterial to the Company's consolidated financial statements.

In accordance with long-standing regulatory treatment, the Company collects through rates the estimated costs of removal on certain of its regulated properties through depreciation expense, with a corresponding credit to accumulated depreciation, depletion, and amortization. These removal costs are non-legal obligations as defined by Statement 143. However, questions regarding the accounting treatment for these obligations have arisen since the issuance of Statement 143. In recent discussions between the industry and the SEC staff, the SEC staff has taken the position that these non-legal asset removal obligations are not covered under Statement 143, but rather should be accounted for as a regulatory liability under Statement 71. Historically, the regulatory authorities which have jurisdiction over the Company's regulated operations have not required the Company to track this amount; rather these costs are addressed prospectively as depreciation rates are set in each general rate order. The Company has made a tentative estimation of its cost of removal liability using current rates since the last general rate order in each of its jurisdictions. However, significant uncertainty exists regarding the ultimate determination of this liability pending, among other issues, clarification of regulatory intent. Further study is ongoing, and the liability may be adjusted as more information is obtained. For the purposes of this Form 10-K, the estimated non-legal asset removal obligation has been reclassified from accumulated deprecation, depletion and amortization to non-current liabilities in other deferred credits on the balance sheet as of December 31, 2003 and 2002. To the extent this estimated liability is adjusted, such amounts will be reclassified between accumulated depreciation, depletion and amortization and other deferred credits and thus will not have an impact on earnings.

Common Stock Options and Awards - On January 1, 2003, the Company adopted Statement of Financial Accounting Standards No. 148, “Accounting for Stock-Based Compensation – Transition and Disclosure” (Statement 148). Statement 148 was an amendment to Statement of Financial Accounting Standards No. 123, “Accounting for Stock-Based Compensation” (Statement 123). The Company elected to begin expensing the fair value of all stock option compensation granted on or after January 1, 2003 under the prospective method allowed by Statement 148. Prior to January 1, 2003, the Company accounted for its stock option compensation under the recognition and measurement principles of APB Opinion No. 25, “Accounting for Stock Issued to Employees” (APB 25), and related interpretations. The following table sets forth the effect on net income and earnings per share as if the Company had applied the fair-value recognition provisions of Statement 123 to stock-based employee compensation in the periods presented.

	2003	2002	2001
	(Thousands of Dollars, except per share amounts)		
Net income, as reported	**$ 112,488**	$ 166,624	$ 101,565
Add: Stock option compensation included in net income, net of related tax effects	**595**	—	—
Deduct: Total stock option compensation expense determined under fair value based method for all awards, net of related tax effects	**1,808**	2,050	1,444
Pro forma net income	**$ 111,275**	$ 164,574	$ 100,121
Earnings per share:			
Basic - as reported	**$ 1.48**	$ 1.40	$ 0.85
Basic - pro forma	**$ 1.46**	$ 1.38	$ 0.84
Diluted - as reported	**$ 1.22**	$ 1.39	$ 0.85
Diluted - pro forma	**$ 1.21**	$ 1.37	$ 0.84

Earnings Per Common Share - In accordance with a pronouncement of the FASB’s Staff at the EITF meeting in April 2001, codified as EITF Topic No. D-95 (Topic D-95), the Company revised its computation of earnings per common share (EPS). In accordance with Topic D-95, the dilutive effect of the Company’s Series A Convertible Preferred Stock was considered in the computation of basic EPS, utilizing the “if-converted” method. Under the Company’s “if-converted” method, the dilutive effect of the Series A Convertible Preferred Stock on EPS cannot be less than the amount that would result from the application of the “two-class” method of computing EPS. The “two-class” method is an earnings allocation formula that determines EPS for the common stock and the participating Series A Convertible Preferred Stock according to dividends declared and participating rights in the undistributed earnings. The Series A Convertible Preferred Stock was a participating instrument with the Company’s common stock with respect to the payment of dividends. For all periods presented, the “two-class” method resulted in additional dilution. See Note S.

As a result of the Company’s repurchase and exchange of its Series A Convertible Preferred Stock with Westar Industries, Inc. in February 2003, the Company no longer applied the provisions of Topic D-95 to its EPS computation for periods beginning February 2003.

Labor Force - The Company employed 4,342 people at December 31, 2003. Approximately 19 percent of the workforce, all of whom are employed by KGS, is covered by collective bargaining agreements with 11 percent covered by agreements that expire in 2004 and 8 percent covered by agreements that expire in 2006.

Use of Estimates - Certain amounts included in or affecting the Company's financial statements and related disclosures must be estimated, requiring the Company to make certain assumptions with respect to values or conditions which cannot be known with certainty at the time the financial statements are prepared. Items which may be estimated include, but are not limited to, the economic useful life of assets, fair value of assets and liabilities, obligations under employee benefit plans, provisions for uncollectible accounts receivable, unbilled revenues for gas delivered but for which meters have not been read, gas purchased expense for gas received but for which no invoice has been received, provision for income taxes including any deferred tax valuation allowances, the results of litigation and various other recorded or disclosed amounts. Accordingly, the reported amounts of the Company's assets and liabilities, revenues and expenses, and related disclosures are necessarily affected by these estimates.

The Company evaluates these estimates on an ongoing basis using historical experience, consultation with experts and other methods the Company considers reasonable based on the particular circumstances. Nevertheless, actual results may differ significantly from the estimates. Any effects on the Company's financial position or results of operations from revisions to these estimates are recorded in the period when the facts that give rise to the revision become known.

Reclassifications - Certain amounts in prior period consolidated financial statements have been reclassified to conform to the 2003 presentation. Such reclassifications did not impact previously reported net income or shareholder's equity.

Definitions

Following are definitions of abbreviations used in this Form 10-K:

Bbl	42 United States (U.S.) gallons, the basic unit for measuring crude oil and natural gas condensate
MBbls	One thousand barrels
MBbls/d	One thousand barrels per day
MMBbls	One million barrels
Btu	British thermal unit - a measure of the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit
MMBtu	One million British thermal units
MMMBtu/d	One billion British thermal units per day
Mcf	One thousand cubic feet of gas
MMcf	One million cubic feet of gas
MMcf/d	One million cubic feet of gas per day
Mcfe	Mcf equivalent, whereby barrels of oil are converted to Mcf using six Mcfs of natural gas to one barrel of oil
Bcf	One billion cubic feet of gas
Bcf/d	One billion cubic feet of gas per day
Bcfe	Bcf equivalent, whereby barrels of oil are converted to Bcf using six Bcfs of natural gas to one million barrels of oil
NGLs	Natural gas liquids
Mwh	Megawatt hour

(B) ACQUISITIONS AND DISPOSITIONS

On December 22, 2003, the Company purchased approximately $240 million of Texas gas and oil properties and related flow lines from a partnership owned by Wagner & Brown, Ltd. of Midland, Texas. The results of operations for these assets have been included in the Company's consolidated financial statements since that date. The acquisition included approximately 318 wells, 271 of which the Company operates, and 177.2 Bcfe of estimated proved gas and oil reserves as of the September 1, 2003 effective date, with additional probable and possible gas reserve potential. Net production from these properties is approximately 26,000 Mcfe per day.

In December 2003, the Company acquired NGL Storage and Pipeline facilities located in Conway, Kansas for approximately $13.7 million from ChevronTexaco. In the prior two years the Company had leased and operated these facilities.

In October 2003, the Company completed a transaction to sell certain Texas transmission assets for a sales price of approximately $3.1 million. A charge against accumulated depreciation of approximately $7.8 million was recorded in accordance with Statement 71 and the regulatory accounting requirements of the FERC and TRC.

In August 2003, the Company acquired the gas distribution system at the United States Army's Fort Bliss in El Paso, Texas for $2.4 million. The gas distribution system at Fort Bliss has approximately 2,500 customers.

In August 2003, the Company acquired a pipeline system that extends through the Rio Grande Valley region in Texas for $3.6 million. The TGS pipeline system serves the city gate points for the TGS Rio Grande Valley service area, providing service to approximately 10 transport customers, two power plants and offers access to production wells that supply the area.

In January 2003, the Company closed the sale of approximately 70 percent of the natural gas and oil producing properties of its Production segment for a cash sales price of $294 million, including adjustments. See Note C.

On January 3, 2003, the Company purchased the Texas gas distribution business and other assets from Southern Union Company (Southern Union). The results of operations for these assets have been included in the Company's consolidated financial statements since that date. The Company paid approximately $436.6 million for these assets, including $16.6 million in working capital adjustments. The primary assets acquired were gas distribution operations that currently serve approximately 544,000 customers in cities located throughout Texas, including the major cities of El Paso and Austin, as well as the cities of Port Arthur, Galveston, Brownsville and others. Over 90 percent of the customers are residential. The other assets acquired include a 125-mile natural gas transmission system, as well as other energy related domestic assets involved in gas marketing, retail sales of propane and distribution of propane. The purchase also includes natural gas distribution investments in Mexico. The gas distribution assets are operated under TGS.

The unaudited pro forma information in the table below presents a summary of the Company's consolidated results of operations as if the acquisition of the Texas assets from Southern Union had occurred at the beginning of the period presented. The results do not necessarily reflect the results that would have been obtained if the acquisition had actually occurred on the dates indicated or results that may be expected in the future. The December 22, 2003 acquisition from Wagner & Brown, Ltd. is not included in the pro forma information in the table below since this information is not available and the Company believes the amount is immaterial.

	Pro Forma Twelve Months Ended December 31, 2002
	(Thousands of Dollars, except per share amounts)
Operating Revenues	$ 2,191,193
Net Revenues	$ 1,084,262
Income from continuing operations	$ 186,028
Net Income	$ 196,676
Earnings per share from continuing operations - diluted	$ 1.35
Earnings per share - diluted	$ 1.44

The addition of the Texas gas distribution assets fits well with the Company's concentration in the mid-continent region of the United States by adding to its distribution systems in Oklahoma and Kansas. The acquisition also adds a stable revenue source as a majority of the margins are protected from the impact of weather swings due to rate designs that include a fixed customer charge. The regulatory environment in which municipalities set rates diversifies regulatory risk.

On December 13, 2002, the Company closed the sale of a portion of its midstream natural gas assets for a cash sales price of approximately $92 million to an affiliate of Mustang Fuel Corporation, a private, independent oil and gas company. The assets that were sold are located in north central Oklahoma and include three natural gas processing plants and related gathering systems and interest in a fourth natural gas processing plant.

In December 2002, the Company sold its property rights in Sayre Storage Company, a natural gas storage field, and entered into a long-term agreement with the purchaser whereby the Company retains storage capacity consistent with the Company's original ownership position.

In the second quarter of 2002, the Company sold its remaining shares of Magnum Hunter Resources (MHR) common stock for a pre-tax gain of approximately $7.6 million, which is included in the Other segment's other income for the year ended December 31, 2002. The Company retained approximately 1.5 million stock purchase warrants.

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In June 2001, the Company sold its 40 percent interest in K. Stewart Petroleum Corporation, a privately held exploration company, for a sales price of $7.7 million.

(C) DISCONTINUED OPERATIONS

In January 2003, the Company sold approximately 70 percent of the natural gas and oil producing properties of its Production segment (the component) for an adjusted cash price of $294 million. The component is accounted for as a discontinued operation in accordance with Statement 144. Accordingly, amounts in the Company’s financial statements and related notes for all periods shown reflect discontinued operations accounting. The Company’s decision to sell the component was based on strategic evaluations of the Production segment’s goals and favorable market conditions. The properties sold were in Oklahoma, Kansas and Texas. The effective date of the sale was November 30, 2002. The Company recognized a pretax gain on the sale of the discontinued component of approximately $61.2 million in 2003. The gain reflects the cash received less adjustments, selling expenses and the net book value of the assets sold.

The amounts of revenue, costs and income taxes reported in discontinued operations are as follows.

	Years Ended December 31,		
	2003	**2002**	**2001**
		(Thousands of Dollars)	
Natural gas sales	**$ 6,036**	$ 57,520	$ 76,218
Oil sales	**1,705**	6,024	6,030
Other revenues	**—**	407	162
Net revenues	**7,741**	63,951	82,410
Operating costs	**1,985**	21,660	19,010
Depreciation, depletion, and amortization	**1,937**	24,836	23,777
Operating income	**3,819**	17,455	39,623
Income taxes	**1,477**	6,807	14,744
Income from discontinued component	**$ 2,342**	$ 10,648	$ 24,879
Gain on sale of discontinued component, net of tax of $21.5 million	**$ 39,739**	$ —	$ —

The major classes of discontinued assets and liabilities included in the consolidated balance sheet are as follows.

	December 31, 2002
	(Thousands of Dollars)
Assets	
Trade accounts and notes receivable, net	$ 95
Materials and supplies	181
Total current assets of discontinued component	276
Property, plant, and equipment	371,534
Accumulated depreciation, depletion, and amortization	148,798
Net property, plant, and equipment	222,736
Other	2,325
Total non-current assets of discontinued component	225,061
Total assets of discontinued component	$ 225,337
Liabilities	
Accounts payable	$ 1,445
Deferred income taxes	—
Total current liabilities of discontinued component	1,445
Deferred income taxes	40,285
Other	730
Total non-current liabilities of discontinued component	41,015
Total liabilities of discontinued component	$ 42,460

(D) PRICE RISK MANAGEMENT ACTIVITIES AND DERIVATIVE FINANCIAL INSTRUMENTS

Market risks are monitored by a risk control group that operates independently from the operating segments that create or actively manage these risk exposures. The risk control group ensures compliance with the Company's risk management policies.

Risk Policy and Oversight - The Company controls the scope of risk management, marketing and trading operations through a comprehensive set of policies and procedures involving senior levels of management. The Company's Board of Directors affirms the risk limit parameters with its audit committee having oversight responsibilities for the policies. A risk oversight committee, comprised of corporate and business segment officers, oversees all activities related to commodity price, credit and interest rate risk management, marketing and trading activities. The committee also proposes risk metrics including value-at-risk (VAR) and position loss limits. The Company has a corporate risk control organization led by the Senior Vice President of Financial Services and the Vice President of Audit Services and Risk Control, who are assigned responsibility for establishing and enforcing the policies, procedures and limits and evaluating the risks inherent in proposed transactions. Key risk control activities include credit review and approval, credit and performance risk measurement and monitoring, validation of transactions, portfolio valuation, VAR and other risk metrics.

To the extent open commodity positions exist, fluctuating commodity prices can impact the financial results and financial position of the Company either favorably or unfavorably. As a result, the Company cannot predict with precision the impact risk management decisions may have on the business, operating results or financial position.

Accounting Treatment - The Company accounts for derivative instruments and hedging activities in accordance with Statement 133. Under Statement 133, entities are required to record all derivative instruments in price risk management assets and liabilities at fair value. The accounting for changes in the fair value of a derivative instrument depends on whether it has been designated and qualifies as part of a hedging relationship and, if so, the reason for holding it. If certain conditions are met, entities may elect to designate a derivative instrument as a hedge of exposure to changes in fair values, cash flows or foreign currencies. For hedges of exposure to changes in fair value, the gain or loss on the derivative instrument is recognized in earnings in the period of change together with the offsetting loss or gain on the hedged item attributable to the risk being hedged. The difference between the change in fair value of the derivative instrument and the change in fair value of the hedged item represents hedge ineffectiveness. For hedges of exposure to changes in cash flow, the effective portion of the gain or loss on the derivative instrument is reported initially as a component of other comprehensive income and is subsequently reclassified into earnings when the forecasted transaction affects earnings. Any amounts excluded from the assessment of hedge effectiveness, as well as the ineffective portion of the hedge, are reported in earnings immediately.

As required by Statement 133, the Company formally documents all relationships between hedging instruments and hedged items, as well as risk management objectives, strategies for undertaking various hedge transactions and methods for assessing and testing correlation and hedge ineffectiveness. The Company specifically identifies the asset, liability, firm commitment or forecasted transaction that has been designated as the hedged item. The Company assesses the effectiveness of hedging relationships, both at the inception of the hedge and on an ongoing basis.

In July 2003, the EITF reached a consensus on EITF Issue No. 03-11, “Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities, and Not ‘Held for Trading Purposes’ as Defined in EITF Issue No. 02-3, ‘Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities’” (EITF 03-11). EITF 03-11 provides that the determination of whether realized gains and losses on physically settled derivative contracts not “held for trading purposes” should be reported in the income statement on a gross or net basis is a matter of judgment that depends on the relevant facts and circumstances. Consideration of the facts and circumstances should be made in the context of the various activities of the entity rather than based solely on the terms of the individual contracts. The Company has evaluated its activities and will continue to present the financial results of all energy trading contracts on a net basis.

In 2002 and 2001 the Company accounted for price risk management activities for its energy trading contracts in accordance with EITF 98-10. EITF 98-10 required entities involved in energy trading activities to account for energy trading contracts using mark-to-market accounting. Forwards, swaps, options, and energy transportation and storage contracts utilized for trading activities were reflected at fair value as assets and liabilities from price risk management activities in the consolidated balance sheets. Changes in the fair value were recognized as energy trading revenues, net, in the consolidated statements of income.

In October 2002, the Emerging Issues Task Force (EITF) of the FASB rescinded EITF 98-10. As a result, energy-related contracts that are not accounted for pursuant to Statement 133 are no longer carried at fair value, but rather will be accounted for on an accrual basis as executory contracts. As a result of the rescission of EITF 98-10, the Task Force also agreed that energy trading inventories carried under storage agreements should no longer be carried at fair value, but should be carried at the lower of cost or market. The rescission was effective for all fiscal periods beginning after December 31, 2002 and for all existing energy trading contracts and inventory as of October 25, 2002. Additionally, the rescission applied immediately to contracts entered into on or after October 25, 2002. Changes to the accounting for existing contracts as a result of the rescission of EITF 98-10 were reported as a cumulative effect of a change in accounting principle on January 1, 2003. This resulted in a cumulative effect loss, net of tax, of $141.8 million. The impact from this change was non-cash.

Trading Activities

The Company’s operating results are impacted by commodity price fluctuations. The Company routinely enters into derivative financial instruments to minimize the risk of commodity price fluctuations related to purchase and sale commitments, fuel requirements, transportation and storage contracts, and natural gas marketing and trading inventories.

The Marketing and Trading segment includes the Company’s wholesale and retail natural gas marketing and trading operations. The Marketing and Trading segment generally attempts to balance its fixed-price physical and financial purchase and sale commitments in terms of contract volumes and the timing of performance and delivery obligations. With respect to the net open positions that exist, fluctuating commodity market prices can impact the Company’s financial position and results of operations, either favorably or unfavorably. The net open positions are actively managed and the impact of the changing prices on the Company’s financial condition at a point in time is not necessarily indicative of the impact of price movements throughout the year.

Fair Value Hedges - The Marketing and Trading segment uses basis swaps to hedge the fair value of certain transportation commitments. At December 31, 2003, net price risk management assets include $8.6 million to recognize the fair value of the Marketing and Trading segment’s derivatives that are designated as fair value hedging instruments. Price risk management liabilities include $8.6 million at December 31, 2003 to recognize the change in fair value of the related hedged firm commitment. The ineffectiveness of $0.7 million related to these hedges is included in energy trading revenues, net.

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Cash Flow Hedges - The Marketing and Trading segment uses futures and swaps to hedge the cash flows associated with its natural gas inventories. Accumulated other comprehensive income at December 31, 2003, includes losses of approximately $15.1 million, net of tax, related to these hedges that will be realized within the next 13 months. When gas inventory is sold, net gains and losses are reclassified out of accumulated other comprehensive income to energy trading revenues, net. Ineffectiveness related to these cash flow hedges was approximately $7.9 million in 2003.

Fair Value - At December 31, 2002, price risk management assets and liabilities include the fair value of derivative financial instruments, purchase and sales commitments, fuel requirements, transportation and storage contracts, and inventories related to trading price risk management activities. Due to the rescission of EITF 98-10, energy-related contacts that are not derivatives and energy trading inventories are no longer included in price risk management assets and liabilities at December 31, 2003.

The fair value and average fair value of the Marketing and Trading segment's price risk management assets and liabilities during 2003 and 2002 are set forth as follows.

	Fair Value December 31, 2003		Average Fair Value (a) December 31, 2003	
	Assets	**Liabilities**	**Assets**	**Liabilities**
	(Thousands of Dollars)			
Energy commodities	**$290,914**	**$339,310**	**$237,721**	**$296,340**

(a) Computed using the ending balance at the end of each quarter.

	Fair Value December 31, 2002		Average Fair Value (a) December 31, 2002	
	Assets	**Liabilities**	**Assets**	**Liabilities**
	(Thousands of Dollars)			
Energy commodities	$920,265	$720,257	$939,561	$750,603

(a) Computed using the ending balance at the end of each quarter.

The Company did not hold any other commodity-type contracts for trading price risk management purposes at December 31, 2003.

Notional Value - The notional contractual quantities associated with trading price risk management activities are set forth as follows.

	Volumes Purchased	Volumes Sold
December 31, 2003:		
Natural gas options (Bcf)	**46.5**	**49.2**
Crude oil options (MBbls)	**176.9**	**482.6**
Natural gas swaps (Bcf)	**1,185.7**	**943.4**
Crude oil swaps (MBbls)	**4,416.0**	**4,416.0**
Natural gas futures (Bcf)	**297.7**	**318.8**
Crude oil futures (MBbls)	**1,720.0**	**1,480.0**
December 31, 2002:		
Natural gas options (Bcf)	134.3	118.8
Crude oil options (MBbls)	9.3	9.4
Natural gas swaps (Bcf)	1,485.7	1,357.1
Crude oil swaps (MBbls)	7.6	5.9
Ethane swaps (MBbls)	1.1	0.8
Propane swaps (MBbls)	0.7	0.6
Natural gas futures (Bcf)	250.2	278.4
Crude oil futures (MBbls)	5.5	5.6

Notional amounts reflect the volume and indicated activity of transactions, but do not represent the amounts exchanged by the parties or cash requirements associated with these financial instruments. Accordingly, notional amounts do not accurately measure the Company's exposure to market or credit risk.

Credit Risk - In conjunction with the market valuation of its energy commodity contracts, the Company provides reserves for risks associated with its contract commitments, including credit risk. Credit risk relates to the risk of loss that the Company would incur as a result of nonperformance by counterparties pursuant to the terms of their contractual obligations. The Company maintains credit policies with regard to its counterparties that management believes significantly minimize overall credit risk. These policies include an evaluation of potential counterparties' financial condition (including credit ratings), collateral requirements under certain circumstances and the use of standardized agreements which allow for netting of positive and negative exposures associated with a single counterparty.

Counterparties in its trading portfolio consist primarily of financial institutions, major energy companies and local distribution companies. This concentration of counterparties may impact the Company's overall exposure to credit risk, either positively or negatively in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions. Based on the Company's policies, its exposures, its credit and other reserves, the Company does not anticipate a material adverse effect on financial position or results of operations as a result of counterparty nonperformance.

Non-Trading Activities

Financial instruments are also utilized to hedge the impact of fair value fluctuations for anticipated sales of natural gas and crude oil production, anticipated fuel requirements, and inventories of the natural gas liquids business. The Company is subject to the risk of interest rate fluctuations in the normal course of business. The Company manages interest rate risk through the use of fixed rate debt, floating rate debt and, at times, interest rate swaps.

Operating margins associated with the Gathering and Processing segment's natural gas gathering, processing and fractionation activities are sensitive to changes in natural gas liquids prices, principally as a result of contractual terms under which natural gas is processed and products are sold as well as the availability of inlet volumes. Also, certain processing plant assets are impacted by changes in, and the relationship between, natural gas and natural gas liquids prices, which, in turn influences the volumes of gas processed.

Fair Value Hedges - Currently, $740 million of fixed rate debt is swapped to floating. The floating rate debt is based on both three and six-month London InterBank Offered Rate (LIBOR). At December 31, 2003, $500 million of the $740 million had the interest rate locked through the first quarter of 2005. In 2003, the Company recorded a $55.8 million net increase in price risk management assets to recognize the interest rate swaps at fair value. Long-term debt was also increased to recognize the change in fair value of the related hedged liability. Ineffectiveness related to these hedges is included in interest expense. See Note K.

Cash Flow Hedges - The Production segment periodically enters into derivative instruments to hedge the cash flows associated with its exposure to changes in the price of natural gas. The realized gains and losses were reclassified from accumulated other comprehensive income resulting from the settlement of contracts when the natural gas was sold and are reported in operating revenues. Accumulated other comprehensive income at December 31, 2003 includes losses of approximately $0.2 million, net of tax, for the production hedges that will be realized in earnings within the next 12 months.

The Company's regulated businesses also use derivative instruments from time to time. Gains or losses associated with the derivative instruments are included in and recoverable through the monthly purchased gas adjustment. At December 31, 2003, KGS had derivative instruments in place to hedge the cost of gas purchases for 13.5 Bcf of gas.

The following table represents the estimated fair values of derivative instruments related to the Company's non-trading price risk management activities. The fair value is the carrying value for these instruments at December 31, 2003 and 2002.

		Approximate Fair Value*
		(Thousands of Dollars)
December 31, 2003		
Natural gas commodities - cash flow hedges	**$**	**(29,117)**
Interest rate swaps - fair value hedges	**$**	**55,750**
Natural gas commodities - other	**$**	**8,640**
December 31, 2002		
Natural gas commodities - cash flow hedges	$	921
Interest rate swaps - fair value hedges	$	79,021
Natural gas commodities - other	$	—

* This excludes hedges related to the regulated entities as any income statement effect will be recovered through the cost of gas.

Notional Value - The Company was a party to natural gas commodity derivative instruments including swaps and options covering 17.6 Bcf and 6.6 Bcf of natural gas for December 31, 2003 and 2002, respectively.

Credit Risk - The Company maintains credit policies with regard to its counterparties that management believes significantly minimize overall credit risk. These policies include an evaluation of potential counterparties' financial condition (including credit ratings), collateral requirements under certain circumstances and the use of standardized agreements which allow for netting of positive and negative exposures associated with a single counterparty.

The counterparties to the non-trading instruments include large integrated energy companies. Accordingly, the Company does not anticipate a material adverse effect on financial position or results of operations as a result of counterparty nonperformance.

Financial Instruments

The following table represents the carrying amounts and estimated fair values of the Company's financial instruments, excluding trading activities, which are marked to market, and non-trading commodity instruments, which are listed in the table above.

	Book Value	Approximate Fair Value
	(Thousands of Dollars)	
December 31, 2003		
Cash and cash equivalents	**$ 12,172**	**$ 12,172**
Accounts and notes receivable	**$ 970,141**	**$ 970,141**
Notes payable	**$ 600,000**	**$ 600,000**
Long-term debt	**$ 1,886,777**	**$ 2,010,596**

	Book Value	Approximate Fair Value
	(Thousands of Dollars)	
December 31, 2002		
Cash and cash equivalents	$ 73,522	$ 73,522
Accounts and notes receivable	$ 773,017	$ 773,017
Notes payable	$ 265,500	$ 265,500
Long-term debt	$ 1,520,305	$ 1,547,234

The fair value of cash and cash equivalents, accounts and notes receivable and notes payable approximate book value due to their short-term nature. The estimated fair value of long-term debt has been determined using quoted market prices of the same or similar issues, discounted cash flows, and/or rates currently available to the Company for debt with similar terms and remaining maturities.

(E) REGULATORY ASSETS

The following table presents a summary of regulatory assets, net of amortization, at December 31, 2003 and 2002.

	December 31, 2003	December 31, 2002
	(Thousands of Dollars)	
Recoupable take-or-pay	**$ 64,171**	$ 69,812
Pension costs	**18,060**	6,942
Postretirement costs other than pension	**59,118**	55,901
Transition costs	**16,691**	21,005
Reacquired debt costs	**20,635**	21,512
Income taxes	**21,782**	25,142
Weather normalization	**1,075**	3,746
Line replacements	**495**	5,072
Service lines	**3,250**	1,882
Other	**8,638**	6,964
Regulatory assets, net	**$ 213,915**	$ 217,978

The remaining recovery period for the assets that the Company is not earning a return on is shown in the table below.

	December 31, 2003	Remaining Recovery Period
	(Thousands of Dollars)	*(Months)*
Postretirement costs other than pension - Oklahoma	**$ 6,512**	117
Income taxes - Oklahoma	**$ 5,460**	90 - 106
Transition costs	**$ 16,691**	407
Other - Texas	**$ 1,919**	12 - 24

Regulatory assets increased by $21.2 million as a result of the TGS acquisition on January 3, 2003.

On September 17, 2003, the KCC issued an order approving a $45 million rate increase for the Company’s distribution customers in Kansas pursuant to a stipulated settlement agreement with KGS. The order primarily authorized the recovery of postretirement benefit costs over nine years. The order also made the weather normalization adjustment rider, which had been renewed annually, a permanent component of customer rates.

On January 30, 2004, the OCC approved ONG’s request that it be allowed to recover costs that the Company has incurred since 2000 when it assumed responsibility for its customers’ service lines and enhanced its efforts to protect pipelines from corrosion. ONG also sought to recover costs related to its investment in gas in storage and rising levels of fuel-related bad debts. The plan allows ONG to increase its annual rates $17.7 million with $10.7 million as interim and subject to refund until a final determination at the Company’s next general rate case. ONG has committed to filing for a general rate review no later than January 31, 2005. Approximately $7.0 million annually is considered final and not subject to refund. Through December 31, 2003, the Company has deferred approximately $6.0 million associated with these OCC directives. These deferred costs are included in the caption “Service Lines” and “Other” in the regulatory assets table above.

The OCC has authorized ONG’s recovery of the take-or-pay settlement, pension and postretirement benefit costs over a 10 to 20 year period. The KCC has authorized KGS’ recovery of postretirement benefit costs over a nine-year period for KGS in the September 17, 2003 order. TGS is authorized to recover pension and postretirement benefit costs over various periods based on the approval of the TRC and the various municipalities that it serves.

The Company amortizes reacquired debt costs in accordance with the accounting rules prescribed by the OCC and KCC. These costs were included as a component of interest in the most recent rate filing with the OCC and were included in the rate order issued by the KCC on September 17, 2003.

Recovery through rates resulted in amortization of regulatory assets of approximately $11.8 million, $11.9 million and $11.3 million for the years ended December 31, 2003, 2002 and 2001, respectively.

(F) GOODWILL

The Company adopted Statement 142 on January 1, 2002. Under Statement 142, goodwill is no longer amortized but reviewed for impairment annually or more frequently if certain indicators arise. Statement 142 prescribes a two-phase process for testing the impairment of goodwill. The first phase identifies indicators of impairment. If impairment is indicated, the second phase measures the impairment. In accordance with the provisions of Statement 142, the Company performed the first of the required impairment tests of goodwill and, based upon this transition impairment test, no impairment to goodwill was indicated and the Company did not record a charge in connection with the adoption of Statement 142. The Company performed its annual test of goodwill as of January 1, 2003, and will perform it annually thereafter. Had the Company been accounting for its goodwill under Statement 142 for all periods presented, the Company's net income and earnings per share would have been as follows.

	Years Ended December 31,		
	2003	**2002**	**2001**
		(Thousands of Dollars)	
Reported net income	**$ 112,488**	$ 166,624	$ 101,565
Add back goodwill amortization, net of tax	**—**	—	2,747
Pro forma adjusted net income	**$ 112,488**	$ 166,624	$ 104,312
Basic earnings per share:			
Reported earnings per share	**$ 1.48**	$ 1.40	$ 0.85
Goodwill amortization, net of tax	**—**	—	0.02
Pro forma adjusted basic earnings per share	**$ 1.48**	$ 1.40	$ 0.87
Diluted earnings per share:			
Reported earnings per share	**$ 1.22**	$ 1.39	$ 0.85
Goodwill amortization, net of tax	**—**	—	0.02
Pro forma adjusted diluted earnings per share	**$ 1.22**	$ 1.39	$ 0.87

The changes in the carrying amount of goodwill for the years ended December 31, 2003 and 2002 are as follows.

	Balance December 31, 2002	Adjustments	Balance December 31, 2003
		(Thousands of Dollars)	
Gathering and Processing	$ 34,343	$ —	**$ 34,343**
Transportation and Storage	22,183	105	**22,288**
Distribution	51,368	107,361	**158,729**
Marketing and Trading	5,616	4,639	**10,255**
Total consolidated	$ 113,510	$ 112,105	**$ 225,615**

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	Balance December 31, 2001	Adjustments	Balance December 31, 2002
		(Thousands of Dollars)	
Gathering and Processing	$ 34,343	$ —	$ 34,343
Transportation and Storage	22,183	—	22,183
Distribution	51,368	—	51,368
Marketing and Trading	5,616	—	5,616
Total consolidated	$ 113,510	$ —	$ 113,510

The 2003 goodwill additions are the result of the January 2003 acquisition of the Texas assets from Southern Union.

(G) COMPREHENSIVE INCOME

The table below gives an overview of comprehensive income for the periods indicated.

	Years Ended December 31,			
	2003		2002	
	(Thousands of Dollars)			
Net income		**$ 112,488**		$ 166,624
Other comprehensive income (loss):				
Unrealized gains (losses) on derivative instruments	**$ (29,203)**		$ 3,463	
Unrealized holding gains arising during the period	**396**		13,087	
Realized (gains) losses in net income	**3,306**		(16,512)	
Minimum pension liability adjustment	**5,782**		(6,166)	
Other comprehensive loss before taxes	**(19,719)**		(6,128)	
Income tax benefit on other comprehensive loss	**7,639**		2,362	
Other comprehensive loss		**$ (12,080)**		$ (3,766)
Comprehensive income		**$ 100,408**		$ 162,858

Accumulated other comprehensive loss at December 31, 2003, includes unrealized gains and losses on derivative instruments and minimum pension liability adjustments.

(H) CAPITAL STOCK

Series A Convertible Preferred Stock - The Company issued Series A Convertible Preferred Stock, par value $0.01 per share, at the time of the November 1997 transaction with Westar Energy, Inc. (formerly Western Resources, Inc.). On February 5, 2003, the Company repurchased from Westar Industries, a wholly owned subsidiary of Westar Energy (collectively "Westar"), approximately 9 million shares (approximately 18.1 million shares of common stock equivalents) of its Series A Convertible Preferred Stock. The Company exchanged the remaining shares for 21.8 million shares of its newly-created Series D Convertible Preferred Stock. See further discussion in the Westar section of this footnote. The Series A Convertible Preferred Stock was cancelled pursuant to the repurchase and exchange.

The terms of the Series A Convertible Preferred Stock provided that holders were entitled to receive a dividend payment, with respect to each dividend period of the common stock, equal to 3.0 times the dividend amount declared in respect to each share of common stock for the first five years of the agreement. In November 2002, the rate was reduced to 2.5 times the dividend amount declared in respect to each share of common stock, and at no time could the dividend have been less than $1.80 per share on an aggregate annual basis. The dividend multiple was adjusted to reflect the 2001 two-for-one common stock split. Preferential cash dividends were paid quarterly on each share of Series A Convertible Preferred Stock, but those dividends were not cumulative to the extent they are not paid on any dividend payment date.

The Series A Convertible Preferred Stock was convertible, subject to certain restrictions, at the option of the holder, into ONEOK, Inc. Common Stock at the rate of two shares for each share of Series A Convertible Preferred Stock.

The liquidation preference of the Series A Convertible Preferred Stock was equal to that payable per share of the Company's Common Stock, as adjusted to reflect any stock split or similar events, assuming conversion of all outstanding shares of the Series A Convertible Preferred Stock immediately prior to the event triggering the liquidation preference, plus any dividends.

Holders of Series A Convertible Preferred Stock were entitled to vote together with holders of the Company's Common Stock with respect to certain matters. Holders of Series A Convertible Preferred Stock could not vote in any election of directors to the Company's Board of Directors or on any matter submitted to the Company's shareholders other than those previously discussed and other matters as required by law.

Series B Convertible Preferred Stock - The terms of Series B Convertible Preferred Stock are the same as Series A Convertible Preferred Stock, except that the dividend amount is equal to the greater of 2.5 times the common stock dividend, and at no time could the dividend be less than $1.50 per share on an aggregate annual basis during the first five years after the agreement, which ended November 27, 2002, and not less than $1.80 on an aggregate annual basis thereafter. There are no shares of Series B Convertible Preferred Stock currently outstanding.

Series C Preferred Stock - Series C Preferred Stock is designed to protect ONEOK, Inc. shareholders from coercive or unfair takeover tactics. Holders of Series C Preferred Stock are entitled to receive, in preference to the holders of ONEOK Common Stock, quarterly dividends in an amount per share equal to the greater of $0.50 or subject to adjustment, 100 times the aggregate per share amount of all cash dividends, and 100 times the aggregate per share amount (payable in kind) of all non-cash dividends. No Series C Preferred Stock has been issued.

Series D Convertible Preferred Stock - In February 2003, the Company exchanged the remaining shares of Series A Convertible Preferred for 21.8 million shares of Series D Convertible Preferred Stock. During 2003, Westar sold all its equity in the Company, including all of the shares of the Company's common stock and the Company's Series D Convertible Preferred Stock, which converted to common stock when sold. See further discussion in the Westar section of this footnote. The Series D Convertible Preferred Stock was retired after Westar's sale of the preferred shares.

The terms of Series D Convertible Preferred Stock provided that holders were entitled to receive, when and if declared by the Board of Directors, quarterly cash dividends in an amount per share equal to $0.23125. If the Company had not paid dividends on the Series D Convertible Preferred Stock on the dividend payment date for any dividend period, dividends would not have been subsequently paid for that dividend period.

The Company had the option to redeem the Series D Convertible Preferred Stock on or after August 1, 2006, subject to certain stock price requirements.

Series D Convertible Preferred Stock was convertible at any time, at the holder's option, subject to certain provisions.

Holders of Series D Convertible Preferred Stock were entitled to vote together with holders of the Company's common stock with respect to certain matters. Each share of Series D Convertible Preferred Stock carried a number of votes equal to those carried by the number of shares of common stock issuable upon conversion of one share of Series D Convertible Preferred Stock. Holders of Series D Convertible Preferred Stock could not vote in any election of directors to the Company's Board of Directors or on any matter submitted to the Company's shareholders other than those previously discussed and other matters as required by law.

Common Stock - At December 31, 2003, the Company had approximately 185 million shares of authorized and unreserved common stock available for issuance.

In July 2003, the Company began using shares of its common stock from treasury or newly issued shares to meet the purchase requirements generated by participants in its Thrift Plan for Employees of ONEOK, Inc. and Subsidiaries. All participant purchases under this plan are voluntary. During the year ended December 31, 2003, the Company issued 514,292 shares for a total of $10.5 million.

On January 18, 2001, the Company's Board of Directors approved, and on May 17, 2001, the shareholders of the Company voted in favor of, a two-for-one common stock split, which was effected through the issuance of one additional share of common stock for each share of common stock outstanding to holders of record on May 23, 2001, with distribution of the shares on June 11, 2001. The Company retained the current par value of $0.01 per share for all shares of common stock. Shareholders' equity reflects the stock split by reclassifying from paid in capital to common stock an amount equal to the cumulative par value of the additional shares issued to effect the split. All share and per share amounts contained herein for all periods reflect this stock split. Outstanding convertible preferred stock is assumed to convert to common stock on a two-for-one basis in the calculations of earnings per share.

The Board of Directors has reserved 12.0 million shares of ONEOK, Inc.'s common stock for the Direct Stock Purchase and Dividend Reinvestment Plan, of which 172,000 shares, 188,000 shares and 424,000 shares were issued in fiscal years 2003, 2002 and 2001, respectively. In January 2001, the Company amended and restated, in its entirety, the existing Direct Stock Purchase and Dividend Reinvestment Plan. The Company has reserved approximately 10.3 million shares for the Thrift Plan for Employees of ONEOK, Inc. and Subsidiaries, less the number of shares issued to date under this plan.

During 1999, the Company initiated a stock buyback plan for up to 15 percent of its capital stock. The program authorized the Company to make purchases of its common stock on the open market with the timing and terms of purchases and the number of shares purchased to be determined by management based on market conditions and other factors. Through April 30, 2001, the shares purchased under this plan totaled 5.1 million, which has been adjusted for the two-for-one stock split. The purchased shares are held in treasury and available for general corporate purposes, funding of stock-based compensation plans, resale at a future date, and retirement. Purchases were financed with short-term debt or were made from available funds. This plan expired in 2001.

During 2001, the Company approved a second stock buyback plan for up to 10 percent of its capital stock. The program authorized the Company to make purchases of its common stock on the open market with the timing and terms of purchases and the number of shares purchased to be determined by management based on market conditions and other factors. This plan expired in 2002. The Company did not purchase any stock under this plan.

2003 Public Stock Offering - During the first quarter of 2003, the Company conducted public offerings of its common stock and equity units. In connection with these offerings, the Company issued a total of 13.8 million shares of its common stock at the public offering price of $17.19 per share, resulting in aggregate net proceeds to the Company, after underwriting discounts and commissions, of $16.524 per share, or $228 million.

2003 Public Equity Units Offering - In addition to the stock offering described above, the Company issued a total of 16.1 million equity units at the public offering price of $25 per unit, resulting in aggregate net proceeds to the Company, after underwriting discounts and commissions, of $24.25 per equity unit, or $390.4 million. Each equity unit consists of a stock purchase contract for the purchase of the Company's common stock shares and, initially, a senior note described in Note K. The number of shares that the Company will issue for each stock purchase contract issued as part of the equity units will be determined based on the its average closing price over the 20-trading day period ending on the third trading day prior to February 16, 2006. If this average closing price:

- equals or exceeds $20.63, the Company will issue 1.2119 shares of its common stock for each purchase contract or unit;
- equals or is less than $17.19, the Company will issue 1.4543 shares of its common stock for each purchase contract or unit;
- is less than $20.63 but greater than $17.19, the Company will determine the number of shares of its common stock to be issued by multiplying the number of purchase contracts or units by the ratio of $25 divided by the average closing price.

Westar - On January 9, 2003, the Company entered into an agreement with Westar to repurchase a portion of the shares of the Company's Series A Convertible Preferred Stock (Series A) held by Westar and to exchange Westar's remaining shares of Series A for newly-created shares of ONEOK's $0.925 Series D Non-Cumulative Convertible Preferred Stock (Series D). The Series A shares were convertible into two shares of common stock for each share of Series A, reflecting the Company's two-for-one stock split in 2001, and the Series D shares were convertible into one share of common stock for each share of Series D. Some of the differences between the Series D and the Series A were (a) the Series D had a fixed quarterly cash dividend of 23.125 cents per share, (b) the Series D was redeemable by ONEOK at any time after August 1, 2006, at a per share redemption price of $20, in the event that the per share closing price of ONEOK common stock exceeded, at any time prior to the date the notice of redemption was given, $25 for 30 consecutive trading days, (c) each share of Series D was convertible into one share of ONEOK common stock, and (d) with certain exceptions, Westar could not convert any shares of Series D held by it unless the annual per share dividend on ONEOK common stock for the previous year was greater than

92.5 cents and such conversion would not have subjected ONEOK to the Public Utility Holding Company Act of 1935. Also, in connection with that transaction, a new rights agreement, a new shareholder agreement and a new registration rights agreement between ONEOK and Westar became effective. The shareholder agreement restricted Westar from selling five percent or more of ONEOK's outstanding Series D and common stock (assuming conversion of all shares of Series D to be transferred), in a bona fide public underwritten offering, to any one person or group. The agreement allowed Westar to sell up to five percent of ONEOK's outstanding Series D and common stock (assuming conversion of all shares of Series D to be transferred) to any one person or group who did not own more than five percent of ONEOK's outstanding common stock (assuming conversion of all shares of Series D to be transferred). The KCC approved the Company's agreement with Westar on January 17, 2003. On February 5, 2003, the Company consummated the agreement by purchasing $300 million of its Series A from Westar. The Company exchanged Westar's remaining 10.9 million Series A shares for approximately 21.8 million shares of the Company's newly-created Series D. Upon the cash redemption of the Series A shares, the shares were converted to approximately 18.1 million shares of common stock in accordance with the terms of the Series A shares and the prior shareholder agreement with Westar. Accordingly, the redemption is reflected as an increase to common treasury stock. The Series D exchanged for the Series A was recorded at fair value and the premium over the previous carrying value of the Series A is reflected as a decrease in retained earnings. The Company had registered for resale all of the shares of its common stock held by Westar, as well as all the shares of its Series D issued to Westar and all of the shares of its common stock that were issuable upon conversion of the Series D.

On August 5, 2003, Westar conducted a secondary offering to the public of 9.5 million shares of ONEOK common stock at a public offering price of $19.00 per share, which resulted in gross offering proceeds to Westar of approximately $180.5 million. An over-allotment option for an additional 718,000 shares provided Westar with approximately $13.6 million. The Company did not receive any proceeds from the offering. Since Westar received in excess of $150 million of total proceeds from the offering, the Company was allowed, under a new transaction agreement related to the offering, to repurchase $50 million, or approximately 2.6 million shares, of its common stock from Westar at the public offering price of $19.00 per share. The Company's repurchase of those shares occurred immediately following the closing of the Westar offering. Of the shares sold in the Westar public offering, approximately 8.4 million shares represented ONEOK's common stock issued by conversion of ONEOK's Series D owned by Westar. The remaining shares consisted of approximately 1.1 million shares of ONEOK's common stock owned by Westar.

On November 21, 2003, Westar sold its remaining equity in the Company, which included all the shares of common stock Westar owned and all the Company's Series D Convertible Preferred Stock, which converted to shares of common stock when sold.

Dividends - Annual dividends on the Company's common stock for shareholders of record totaled $0.69 per share during the year ended December 31, 2003. On September 18, 2003, the Company's Board of Directors approved an increase in the quarterly dividend on the Company's common stock to $0.18 per share that was applicable to the quarterly dividend declared in September 2003. Due to the timing of the Company's Board of Directors meetings, four quarterly dividends on common stock were declared during the first three quarters of 2003. In January 2004, the Company's Board of Directors increased the quarterly dividend on the Company's common stock to $0.19 per share.

Under the most restrictive covenants of the Company's loan agreements, $405.6 million (82 percent) of retained earnings was available to pay dividends at December 31, 2003. Under the Company's existing credit agreement, it is restricted from declaring or making any dividend payment, directly or indirectly, or incurring any obligation to do so unless the aggregate amount declared, paid or expended after August 31, 1998, would not exceed an amount equal to 100 percent of the Company's net income arising after August 31, 1998, plus $125 million and computed on a cumulative consolidated basis with other such transactions by the Company.

(I) PAID IN CAPITAL

Paid in capital was $815.9 million and $339.7 million for common stock at December 31, 2003 and 2002, respectively. Due to the conversion of the remaining preferred stock in 2003, the Company had no paid in capital for convertible preferred stock at December 31, 2003. Paid in capital for convertible preferred stock was $564.2 million at December 31, 2002.

(J) LINES OF CREDIT AND SHORT-TERM NOTES PAYABLE

Commercial paper and short-term notes payable totaling $600.0 million and $265.5 million were outstanding at December 31, 2003 and 2002, respectively. The commercial paper and short-term notes payable carried average interest rates of 1.24

percent and 1.99 percent at December 31, 2003 and 2002, respectively. The Company has an $850 million short-term unsecured revolving credit facility, which provides a back-up line of credit for commercial paper in addition to providing short-term funds. Interest rates and facility fees are based on prevailing market rates and the Company's credit ratings. No amounts were outstanding under the line of credit and no compensating balance requirements existed at December 31, 2003. Maximum short-term debt from all sources, as approved by the Company's Board of Directors, is $1.2 billion.

The Company's credit agreement contains no restrictions on the transfer of its subsidiaries' assets to ONEOK (the parent company) in the form of loans, advances or cash dividends without the consent of a third party.

(K) LONG-TERM DEBT

The aggregate maturities of long-term debt outstanding at December 31, 2003, are $6.3 million; $341.3 million; $306.3 million; $6.3 million; and $408.8 million for 2004 through 2008, respectively, including $6.0 million, which is callable at the option of the holder in each of those years. Additionally, $186.5 million is callable at par at the option of ONEOK from now until maturity, which is 2019 for $93.7 million and 2028 for $92.8 million.

In the first quarter of 2003, the Company issued long-term debt concurrent with its public equity offering. The Company issued a total of 16.1 million equity units at the public offering price of $25 per unit for a total of $402.5 million. Each equity unit consists of a stock purchase contract for the purchase of shares of the Company's common stock and, initially, a senior note due February 16, 2008, issued pursuant to the Company's existing Indenture with SunTrust Bank, as trustee. The equity units carry a total annual coupon rate of 8.5 percent (4.0 percent annual face amount of the senior notes plus 4.5 percent annual contract adjustment payments). The interest expense associated with the 4.0 percent senior notes will be recognized in the income statement on an accrual basis over the term of the senior notes. The present value of the contract adjustment payments was accrued as a liability with a charge to equity at the time of the transactions. Accordingly, there will be no impact on earnings in future periods as this liability is paid, except for the interest recognized as a result of discounting the liability to its present value at the time of the transaction. This interest expense associated with the discounting will be approximately $3.5 million over three years.

In June 2002, the Company issued $3.5 million of long-term variable rate debt, which is secured by the corporate airplane, at an interest rate of 1.25 percent over LIBOR. All remaining long-term notes payable are unsecured. In August 2002, the Company completed a tender offer to purchase all of the outstanding 8.44% Senior Notes due 2004 and the 8.32% Senior Notes due 2007 for a total purchase price of approximately $65 million. The total purchase price included a premium of approximately $2.9 million and consent fees of approximately $1.8 million to purchase the notes, which are reflected in interest expense in the income statement. In April 2002, the Company retired $240 million of two-year floating rate notes that were issued in April 2000. The interest rate for these notes reset quarterly at a 0.65 percent spread over the three-month LIBOR. The proceeds from the notes were used to fund acquisitions. In 2001, the Company issued a $400 million note at a rate of 7.125%. The proceeds from the note were used to refinance short-term debt.

The Company is subject to the risk of fluctuation in interest rates in the normal course of business. The Company manages interest rate risk through the use of fixed rate debt, floating rate debt and, at times, interest rate swaps. Currently, $740 million of fixed rate debt is swapped to floating. The floating rate debt is based on both three and six-month LIBOR. At December 31, 2003, $500 million of the $740 million had the interest rate locked through the first quarter of 2005. Based on the current LIBOR strip and the locks in place, the weighted average rate on the $740 million will be reduced from 7.01 percent to 3.15 percent. This will result in an estimated savings of $28.6 million during 2004. In 2003, the Company recorded a $55.8 million net increase in price risk management assets to recognize at fair value its derivatives that are designated as fair value hedging instruments. Long-term debt was increased by approximately $55.9 million to recognize the change in fair value of the related hedged liability. The swaps generated $24.4 million of interest rate savings during 2003. See further discussion of interest rate risk in Note D.

The following table sets forth the Company's long-term debt for the periods indicated.

	December 31, 2003	December 31, 2002
	(Thousands of Dollars)	
Long-term notes payable		
7.75% due 2005	**$ 335,000**	$ 350,000
7.75% due 2006	**300,000**	300,000
4.0% due 2008	**402,500**	—
Libor + 1.25% due 2009	**3,027**	3,361
6.0% due 2009	**100,000**	100,000
7.125% due 2011	**400,000**	400,000
7.25% due 2013	**2,421**	—
6.4% due 2019	**93,679**	94,104
6.5% due 2028	**92,865**	93,208
6.875% due 2028	**100,000**	100,000
8.0% due 2051	**1,362**	1,364
Total long-term notes payable	**1,830,854**	1,442,037
Change in fair value of hedged debt	**55,923**	78,268
Unamortized debt discount	**(2,179)**	(2,853)
Current maturities	**(6,334)**	(6,334)
Long-term debt	**$1,878,264**	$1,511,118

The Company's revolving credit facility has customary covenants that relate to liens, investments, fundamental changes in the business, restrictions of certain payments, changes in the nature of the business, transactions with affiliates, burdensome agreements, the use of proceeds, and a limit on the Company's debt to capital ratio. Other debt agreements have negative covenants that relate to liens and sale/leaseback transactions.

(L) EMPLOYEE BENEFIT PLANS

Retirement and Other Postretirement Benefit Plans

Retirement Plans - The Company has defined benefit and defined contribution retirement plans covering substantially all employees. Certain company officers and key employees are also eligible to participate in supplemental retirement plans. The Company generally funds pension costs at a level equal to the minimum amount required under the Employee Retirement Income Security Act of 1974.

The Company elected to delay recognition of the accumulated benefit obligation and amortize it over 20 years as a component of net periodic postretirement benefit cost. The accumulated benefit obligation for the defined benefit pension plan was $625.9 million and $536.9 million at December 31, 2003 and 2002, respectively.

Other Postretirement Benefit Plans - The Company sponsors welfare care plans that provide postretirement medical benefits and life insurance benefits to substantially all employees who retire under the retirement plans with at least five years of service. The postretirement medical plan is contributory, with retiree contributions adjusted periodically, and contains other cost-sharing features such as deductibles and coinsurance; provided further that nonbargaining unit employees retiring between the ages of 50 and 55 who elect postretirement medical coverage, and all nonbargaining unit employees hired on or after January 1, 1999 who elect postretirement medical coverage, pay 100 percent of the retiree premium for participation in the plan. Additionally, any employees that came to the Company through various acquisitions may be further limited in their eligibility to participate or receive any Company contributions.

The postretirement welfare plan provides prescription drug benefits to Medicare eligible retirees. The measurement date for the other postretirement benefit liabilities is prior to the enactment date of the Medicare Reform Act. While the Company believes the recently enacted Medicare reform legislation may have a favorable impact on its obligations, the Company has

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not reflected any impact as of its measurement date. The impact is currently being reviewed and could be recognized as early as the first quarter of 2004.

Measurement - The Company uses a September 30 measurement date for the majority of its plans.

Obligations and Funded Status - The following tables set forth the Company's pension and other postretirement benefit plans benefit obligations, fair value of plan assets and funded status at December 31, 2003 and 2002.

	Pension Benefits December 31,		Postretirement Benefits December 31,	
	2003	**2002**	**2003**	**2002**
	(Thousands of Dollars)			
Change in Benefit Obligation				
Benefit obligation, beginning of period	**$601,830**	$516,096	**$ 177,904**	$ 154,559
Service cost	**14,872**	10,662	**5,391**	3,587
Interest cost	**42,602**	36,782	**12,418**	10,990
Participant contributions	**—**	—	**2,278**	1,769
Plan amendments	**—**	667	**3,818**	(11,987)
Actuarial (gain)/loss	**18,751**	72,310	**45,069**	30,817
Acquisitions (divestitures)	**44,606**	—	**6,932**	—
Benefits paid	**(38,773)**	(34,687)	**(17,416)**	(11,831)
Benefit obligation, end of period	**$683,888**	$601,830	**$ 236,394**	$ 177,904
Change in Plan Assets				
Fair value of assets, beginning of period	**$526,516**	$587,289	**$ 30,269**	$ 27,747
Actual return on assets	**91,783**	(27,505)	**3,319**	1,809
Employer contributions	**5,842**	1,419	**3,674**	713
Acquisitions (divestitures)	**28,504**	—	**—**	—
Benefits paid	**(38,773)**	(34,687)	**—**	—
Fair value of assets, end of period	**$613,872**	$526,516	**$ 37,262**	$ 30,269
Funded status - over (under)	**$ (70,016)**	$ (75,314)	**$(197,226)**	$(147,636)
Unrecognized net asset	**(314)**	(781)	**31,854**	—
Unrecognized transition obligation	**—**	—	**—**	9,061
Unrecognized prior service cost	**5,494**	5,989	**2,537**	—
Unrecognized net (gain) loss	**199,713**	195,532	**103,171**	57,767
Activity subsequent to measurement date	**—**	—	**3,707**	6,303
(Accrued) prepaid pension cost	**$134,877**	$125,426	**$ (55,957)**	$ (74,505)

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Components of Net Periodic Benefit Cost

	Pension Benefits Years Ended December 31,		
	2003	2002	2001
	(Thousands of Dollars)		
Components of Net Periodic Benefit Cost (Income)			
Service cost	**$ 14,872**	$ 10,662	$ 9,751
Interest cost	**42,602**	36,782	36,188
Expected return on assets	**(64,264)**	(67,195)	(61,161)
Amortization of unrecognized net asset at adoption	**(467)**	(467)	(467)
Amortization of unrecognized prior service cost	**613**	790	822
Amortization of (gain)/loss	**2,235**	(1,345)	(4,377)
Net periodic benefit cost (income)	**$ (4,409)**	$(20,773)	$(19,244)

	Postretirement Benefits Years Ended December 31,		
	2003	2002	2001
	(Thousands of Dollars)		
Components of Net Periodic Benefit Cost			
Service cost	**$ 5,391**	$ 3,587	$ 3,074
Interest cost	**12,418**	10,990	10,195
Expected return on assets	**(3,154)**	(2,791)	(2,364)
Amortization of unrecognized net transition obligation at adoption	**3,456**	1,954	1,954
Amortization of unrecognized prior service cost	**(125)**	—	—
Amortization of loss	**3,997**	979	234
Net periodic benefit cost	**$ 21,983**	$ 14,719	$ 13,093

Actuarial Assumptions - The following table sets forth the weighted-average assumptions used to determine benefit obligations at December 31, 2003 and 2002.

	Pension Benefits December 31,		Postretirement Benefits December 31,	
	2003	2002	2003	2002
Discount rate	**6.25%**	6.80%	**6.25%**	6.80%
Compensation increase rate	**4.00%**	4.00%	**4.50%**	4.50%

The following table sets forth the weighted-average assumptions used to determine net periodic benefit costs at December 31, 2003 and 2002.

	Pension Benefits December 31,		Postretirement Benefits December 31,	
	2003	2002	2003	2002
Discount rate	**6.80%**	7.35%	**6.80%**	7.35%
Expected long-term return on plan assets	**9.00%**	9.85%	**9.00%**	9.85%
Compensation increase rate	**4.00%**	4.50%	**4.50%**	4.50%

The overall expected long-term rate of return on assets assumption is an equally weighted blend of historical return, building block, and economic growth/yield to maturity projections determined by the Company based on its independent investment consultants' advice.

Health Care Cost Trend Rates - The following table sets forth the assumed health care cost trend rates at December 31, 2003 and 2002.

	2003	2002
Health care cost trend rate assumed for next year	**9%**	10%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	**5%**	5%
Year that the rate reaches the ultimate trend rate	**2007**	2007

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage point change in assumed health care cost trend rates would have the following effects.

	One-Percentage Point Increase	One-Percentage Point Decrease
	(Thousands of Dollars)	
Effect on total of service and interest cost	**$ 2,010**	$ **(1,621)**
Effect on postretirement benefit obligation	**$ 26,210**	$ **(21,459)**

Plan Assets - The following table sets forth the Company's pension and postretirement benefit plan weighted-average asset allocations at December 31, 2003 and 2002.

	Pension Benefits		Postretirement Benefits	
	Percentage of Plan Assets at December 31,		Percentage of Plan Assets at December 31,	
Asset Category	**2003**	**2002**	**2003**	**2002**
U.S. equities	**56%**	47%	**76%**	68%
International equities	**9%**	9%	**12%**	13%
Investment grade bonds	**8%**	12%	**11%**	18%
High yield bonds	**10%**	11%	**0%**	0%
Insurance contracts	**16%**	20%	**0%**	0%
Other	**1%**	1%	**1%**	1%
Total	**100%**	100%	**100%**	100%

The Company's investment strategy is to invest plan assets in accordance with sound investment practices that emphasize long-term investment fundamentals. The goal of this strategy is to maximize investment returns while managing risk in order to meet the plan's current and projected financial obligations. The plan's investments include a diverse blend of various U.S. and international equities, venture capital investments in various classes of debt securities, and insurance contracts. The target allocation for the investments is as follows.

Insurance contracts/corporate bonds	22%
High yield corporate bonds	10%
Large-cap value equities	15%
Large-cap growth equities	18%
Mid/small-cap value equities	10%
Mid/small-cap growth equities	13%
Large-cap/mid-cap international equities	11%
Venture capital	1%

As part of the Company's risk management for the plans, minimums and maximums have been set for each of the asset classes listed above. All investment managers for the plan are subject to certain restrictions on the securities they purchase and, with the exception of indexing purposes, are prohibited from owning Company stock.

Contributions - The Company expects to contribute $5.6 million to its pension plan and $28.1 million to its other postretirement benefits plan in 2004.

Regulatory Treatment - The OCC, KCC, TRC and applicable rate jurisdictions in Texas have approved the recovery of pension costs and other postretirement benefits costs through rates for ONG, KGS and TGS, respectively. The costs recovered through rates are based on current funding requirements and the net periodic postretirement benefits cost for pension and postretirement costs. Differences, if any, between the expense and the amount ordered through rates are charged to earnings. In the September 17, 2003 rate order the KCC authorized KGS to recover $26.4 million of deferred postretirement and postemployment costs over nine years. The OCC has authorized ONG's recovery of pension and postretirement benefit costs over a 10 to 20 year period. TGS is authorized to recover pension and postretirement benefit costs over various periods based on the approval of the TRC and the various municipalities that it serves.

Other Employee Benefit Plans

Employee Thrift Plan - The Company has a Thrift Plan covering substantially all employees. Employee contributions are discretionary. Subject to certain limits, the Company matches employee contributions. The cost of the plan was $9.6 million, $8.5 million and $8.8 million in fiscal years 2003, 2002 and 2001, respectively.

Postemployment Benefits - The Company pays postemployment benefits to former or inactive employees after employment but before normal retirement in compliance with specific separation agreements. Nonbargaining employees hired after January 1, 1999 are not eligible for this benefit.

(M) COMMITMENTS AND CONTINGENCIES

Leases - The initial lease term of the Company's headquarters building, ONEOK Plaza, is for 25 years, expiring in 2009, with six five-year renewal options. At the end of the initial term or any renewal period, the Company can purchase the property at its fair market value. Annual rent expense for the lease will be approximately $6.8 million until 2009. Rent payments were $9.3 million in fiscal years 2003, 2002 and 2001. Estimated future minimum rental payments for the lease are $9.3 million for each of the years ending December 31, 2004 through 2009.

The Company has the right to sublet excess office space in ONEOK Plaza. The Company received rental revenue of $2.8 million, $3.2 million and $3.5 million in fiscal years 2003, 2002 and 2001, respectively, for various subleases. Estimated minimum future rental payments to be received under existing contracts for subleases are $2.5 million in 2004, $1.8 million in 2005, $1.3 million in 2006, $0.5 million in 2007, $0.4 million in 2008 and a total of $0.3 million thereafter.

Other operating leases include a gas processing plant, office buildings, and equipment. Future minimum lease payments under non-cancelable operating leases (with initial or remaining lease terms in excess of one year) as of December 31, 2003, are $31.8 million in 2004, $34.7 million in 2005, $45.6 million in 2006, $30.1 million in 2007 and $28.3 million in 2008. The above amounts include lease payments for auto leases that are accounted for as operating leases but are treated as capital leases for income tax purposes. Also, the above amounts include the following minimum lease payments relating to the lease of a gas processing plant: $20.9 million in 2004, $24.2 million in 2005, $37.7 million in 2006, $24.2 million in 2007 and $24.2 million in 2008. The Company has a liability for uneconomic lease terms relating to a gas processing plant. Accordingly, the liability is amortized to rent expense in the amount of $13.0 million per year over the term of the lease. The amortization of the liability reduces rent expense; however, the cash outflow under the lease remains the same.

Southwest Gas Corporation - In May 1999, a series of lawsuits were filed in connection with the Company's and Southern Union's failed attempts to merge with Southwest Gas Corporation (Southwest). The Company, Southern Union and Southwest all sued each other and Southern Union made claims against a member of the Arizona Corporation Commission and other individuals, including officers and directors of the Company.

On August 9, 2002, the Company and Southwest settled their claims against each other for a payment of $3.0 million by ONEOK to Southwest. On January 3, 2003, the Company entered into a definitive settlement agreement with Southern Union resolving all remaining legal issues. It also resolved the claims against John A. Gaberino, Jr. and Eugene Dubay related to this matter. Under the terms of the settlement, the Company paid $5.0 million to Southern Union, which is included in the December 31, 2002 financial statements. The Company and its affiliated parties are released from any claims against them brought by Southern Union related to the terminated acquisition of Southwest.

Two substantially identical derivative actions, which were consolidated, were filed by shareholders against members of the Board of Directors and certain officers of the Company alleging violation of their fiduciary duties to the Company by causing or allowing the Company to engage in certain fraudulent and improper schemes related to the planned acquisition of Southwest and waste of corporate assets. The consolidated derivative action has been settled at no significant cost to the Company. The trial Court entered a final judgment on June 24, 2003, approving the settlement by the parties after notice had been given to shareholders.

Environmental - The Company is subject to multiple environmental laws and regulations affecting many aspects of present and future operations, including air emissions, water quality, wastewater discharges, solid wastes and hazardous material and substance management. These laws and regulations generally require the Company to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections and other approvals. Failure to comply with these laws, regulations, permits and licenses may expose the Company to fines, penalties and/or interruptions in operations that could be material to the results of operations. If an accidental leak or spill of hazardous materials occurs from the Company's lines or facilities, in the process of transporting natural gas, or at any facilities that the Company owns, operates or otherwise uses, the Company could be held jointly and severally liable for all resulting liabilities, including investigation and clean up costs, which could materially affect the Company's results, operations and cash flow. In addition, emission controls required under the Federal Clean Air Act and other similar federal and state laws could require unexpected capital expenditures at the Company's facilities. The Company cannot assure that existing environmental regulations will not be revised or that new regulations will not be adopted or become applicable to the Company. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from customers, could have a material adverse effect on the Company's business, financial condition and results of operations.

The Company owns or retains legal responsibility for the environmental conditions at 12 former manufactured gas sites in Kansas. These sites contain potentially harmful materials that are subject to control or remediation under various environmental laws and regulations. A consent agreement with the Kansas Department of Health and Environment (KDHE) presently governs all work at these sites. The terms of the consent agreement allow the Company to investigate these sites and set remediation activities based upon the results of the investigations and risk analysis. The Company has commenced active remediation on three sites with regulatory closure achieved at two of these locations, and has begun assessment at the remaining sites. The site situations are not common and the Company has no previous experience with similar remediation efforts. The Company has not completed a comprehensive study of the remaining nine sites and therefore cannot accurately estimate individual or aggregate costs to satisfy the remedial obligations.

The Company's preliminary review of similar cleanup efforts at former manufactured gas sites reveals that costs can range from $100,000 to $10 million per site. These estimates do not give effect to potential insurance recoveries, recoveries through rates or from unaffiliated parties, to which the Company may be entitled. At this time, the Company has not recorded any amounts for potential insurance recoveries or recoveries from unaffiliated parties, and the Company is not recovering any environmental amounts in rates. Total costs to remediate the two sites, which have achieved regulatory closure, totaled approximately $800,000. Total remedial costs for each of the remaining sites are expected to exceed $400,000 per site, but there is no assurance that costs to investigate and remediate the remaining sites will not be significantly higher. As more information related to the site investigations and remediation activities becomes available, and to the extent such amounts are expected to exceed our current estimates, additional expenses could be recorded. Such amounts could be material to the Company's results of operations and cash flows depending on the remediation done and number of years over which the remediation is completed.

The Company's expenditures for environmental evaluation and remediation have not been significant in relation to the results of operations and there have been no material effects upon earnings or the Company's competitive position during 2003 related to compliance with environmental regulations.

Yaggy Facility - In January 2001, the Yaggy gas storage facility's operating parameters were changed as mandated by the KDHE following natural gas explosions and eruptions of natural gas geysers in or near Hutchison, Kansas. In July 2002, the KDHE issued an administrative order that assessed an $180,000 civil penalty against the Company, based on alleged violations of several KDHE regulations. A status conference was held on June 27, 2003 regarding progress toward reaching an agreed upon consent order. The matter was continued pending further settlement negotiations. The Company believes there are no adverse long-term environmental effects.

Two class action lawsuits have been filed against the Company in connection with the natural gas explosions and eruptions of natural gas geysers that occurred at, and in the vicinity of, the Yaggy facility. These class action lawsuits claim that the explosions were caused by the releases of natural gas from the Company's operations. In addition to the two pending class action matters, sixteen additional lawsuits have been filed against the Company or subsidiaries seeking recovery for various claims related to the Yaggy incident, including property damage, personal injury, loss of business and, in some instances, punitive damage. In February 2003, a jury awarded the plaintiffs in one lawsuit $1.7 million in actual damages. The jury found that 50 percent of the liability related to the Company and 50 percent of the liability related to one of the Company's subsidiaries. The jury also awarded punitive damages against a subsidiary of the Company. A hearing has been set for April 2004 to determine the amount of the punitive damages. Although no assurances can be given, the Company believes that the ultimate resolution of these matters will not have a material adverse effect on the Company's financial position or results of operations. The Company is vigorously defending all claims in these cases and believes that the Company's insurance coverage will provide coverage for any material liability associated with these cases.

U.S. Commodity Futures Trading Commission - On January 9, 2003, the Company received a subpoena from the U.S. Commodity Futures Trading Commission (CFTC) requesting information regarding certain trading by energy and power marketing firms and information provided by the Company to energy industry publications in connection with the CFTC's investigation of trading and trade reporting practices of power and natural gas trading companies. The Company ceased providing such information to energy industry publications in 2002. The Company cooperated fully with the CFTC, producing documents and other material in response to specific requests relating to the reporting of natural gas trading information to energy industry publications, conducting an internal review with regard to its practices in voluntarily reporting information to trade publications, and providing reports on its internal review to the CFTC.

In January 2004, the Company announced a settlement with the CFTC relating to the investigation, whereby the Company agreed, among other things, to pay a civil monetary penalty of $3.0 million. This charge is recorded in earnings for the Marketing and Trading segment for the year ended December 31, 2003. The Company neither admitted nor denied the findings in the CFTC settlement order. The Company does not believe inaccurate trade reporting to the energy industry publications affected the financial accounting treatment of any transactions recorded in the financial statements.

On February 4, 2004, the Company received notice that the Company and its wholly owned subsidiary, ONEOK Energy Marketing and Trading Company, L.P., have been named as two of the defendants in a class action lawsuit filed in the United Sates District Court for the Southern District of New York brought on behalf of persons who bought and sold natural gas futures and options contacts on the New York Mercantile Exchange during the years 2000 through 2002. Although the Company agreed to the civil monetary penalty with the CFTC, it cannot guarantee other additional legal proceedings, civil or criminal fines or penalties, or other regulatory action related to this issue will not arise. Accordingly, the impact of any further action on the financial condition and results of operations cannot be predicted.

Labor Negotiations - On July 28, 2003, KGS and the International Brotherhood of Electrical Workers labor union entered into a three-year bargaining agreement expiring June 30, 2006. Approximately 351 of the KGS employees are members of this labor union, comprising approximately 30 percent of the KGS workforce. The parties agreed to a two percent wage increase effective July 1, 2004 and an additional two percent wage increase effective July 1, 2005. On September 12, 2003, KGS completed negotiations with the remaining three Kansas labor unions to replace collective bargaining agreements that expired on July 31, 2003. Approximately 476 KGS employees are members of those three labor unions, comprising approximately 41 percent of the KGS workforce. The parties agreed to extend the existing agreements for one year with a two percent increase effective retroactively to August 1, 2003. Currently, the Company has no ongoing labor negotiations and there are no other unions representing the Company's employees.

Other - The OCC staff filed an application on February 1, 2001, to review the gas procurement practices of ONG in acquiring its gas supply for the 2000/2001 heating season and to determine if these practices were consistent with least cost procurement practices and whether the Company's procurement decisions resulted in fair, just and reasonable costs being borne by ONG customers. In May 2002, the Company, along with the staff of the Public Utility Division and the Consumer Services Division of the OCC, the Oklahoma Attorney General, and other stipulating parties, entered into a joint settlement agreement resolving this gas cost issue and ongoing litigation related to a contract with Dynamic Energy Resources, Inc.

The settlement agreement will be realized over a three-year period. In July 2002, immediate cash savings were provided to all ONG customers in the form of billing credits with $1.0 million available for former customers returning to the ONG system. If the additional $1.0 million is not fully refunded to customers returning to the ONG system by December 2005, the remainder will be included in the final billing credit. ONG replaced certain gas contracts, which is expected to reduce gas costs by approximately $13.8 million, due to avoided reservation fees between April 2003 and October 2005. Additional savings of approximately $8.0 million from the use of storage service in lieu of those contracts are expected to occur between

November 2003 and March 2005. Any expected savings from the use of storage that are not achieved, any remaining billing credits not issued to returning customers and an additional $1.8 million credit will be added to the final billing credit scheduled to be provided to customers in December 2005.

The Company is a party to other litigation matters and claims, which are normal in the course of its operations. While the results of litigation and claims cannot be predicted with certainty, management believes the final outcome of such matters will not have a material adverse effect on Company's consolidated results of operations, financial position, or liquidity.

(N) INCOME TAXES

The following table sets forth the Company's provisions for income taxes for the periods indicated.

	Years Ended December 31,		
	2003	**2002**	**2001**
		(Thousands of Dollars)	
Current income taxes			
Federal	**$ 16,921**	$ (53,306)	$ (69,273)
State	**1,818**	(9,932)	(13,426)
Total current income taxes from continuing operations	**18,739**	(63,238)	(82,699)
Deferred income taxes			
Federal	**112,242**	139,243	113,882
State	**(454)**	26,480	6,307
Total deferred income taxes from continuing operations	**111,788**	165,723	120,189
Total provision for income taxes before cumulative effect/discontinued operations	**130,527**	102,485	37,490
Total provision for income taxes for the cumulative effect of a change in accounting principle	**(90,456)**	—	(1,356)
Discontinued operations	**22,895**	6,807	14,744
Total provision for income taxes	**$ 62,966**	$109,292	$ 50,878

The following table is a reconciliation of the Company's provision for income taxes for the periods indicated.

	Years Ended December 31,		
	2003	**2002**	**2001**
		(Thousands of Dollars)	
Pretax income from continuing operations	**$344,819**	$258,460	$116,327
Federal statutory income tax rate	**35%**	35%	35%
Provision for federal income taxes	**120,687**	90,461	40,714
Amortization of distribution property investment tax credit	**(522)**	(651)	(764)
State income taxes, net of federal tax benefit	**13,283**	10,756	(4,627)
Other, net	**(2,921)**	1,919	2,167
Income tax expense	**$130,527**	$102,485	$ 37,490

The following table sets forth the tax effects of temporary differences that gave rise to significant portions of the deferred tax assets and liabilities for the periods indicated.

	Years Ended December 31,		
	2003	2002	2001
		(Thousands of Dollars)	
Deferred tax assets			
Accrued liabilities not deductible until paid	**$ 117,784**	$ 111,020	$ 180,331
Net operating loss carryforward	**40,978**	28,645	36,828
Regulatory assets	**17,636**	17,527	9,956
Other	**130,998**	37,002	2,057
Total deferred tax assets	**307,396**	194,194	229,172
Valuation allowance for net operating loss carryforward expected to expire prior to utilization	**18,342**	13,166	6,549
Net deferred tax assets	**289,054**	181,028	222,623
Deferred tax liabilities			
Excess of tax over book depreciation and depletion	**724,153**	617,849	545,398
Investment in joint ventures	**8,323**	8,081	12,198
Regulatory assets	**107,644**	112,200	95,836
Other	**14,484**	48,390	38,472
Total deferred tax liabilities	**854,604**	786,520	691,904
Net deferred tax liabilities before discontinued operations	**$ 565,550**	$ 605,492	$ 469,281
Discontinued operations	**—**	40,285	33,478
Net deferred tax liabilities	**$ 565,550**	$ 645,777	$ 502,759

The Company has remaining net operating loss carryforwards for federal and state income tax purposes of approximately $49.3 million and $403.3 million, respectively, at December 31, 2003, which expire, unless utilized, at various dates through 2023. The valuation allowance for deferred tax assets was $312.0 million and $232.6 million at December 31, 2003 and 2002, respectively. The valuation allowance reflects management's uncertainty as to the realization of a portion of the Company's state net operating losses before they expire. At December 31, 2003, the Company had $6.1 million in deferred investment tax credits recorded in other deferred credits, which will be amortized over the next 12 years.

(O) SEGMENT INFORMATION

Management has divided its operations into six reportable segments based on similarities in economic characteristics, products and services, types of customers, methods of distribution and regulatory environment. These segments are as follows: (1) the Production segment develops and produces natural gas and oil; (2) the Gathering and Processing segment gathers and processes natural gas and fractionates, stores and markets natural gas liquids; (3) the Transportation and Storage segment gathers, transports and stores natural gas for others and buys and sells natural gas; (4) the Distribution segment distributes natural gas to residential, commercial and industrial customers, leases pipeline capacity to others and provides transportation services to end-use customers; (5) the Marketing and Trading segment markets natural gas and oil to wholesale and retail customers and markets electricity to wholesale customers; and (6) the Other segment primarily operates and leases the Company's headquarters building and a related parking facility.

During the first quarter of 2002, the Power segment was combined with the Marketing and Trading segment, eliminating the Power segment. This reflects the Company's strategy of trading around the Company's electric generating power plant. All segment data has been reclassified to reflect this change.

In July 2002, the Company completed a transaction to transfer certain transmission assets in Kansas from the Transportation and Storage segment to the Distribution segment. All historical financial and statistical information has been adjusted for this transfer.

The accounting policies of the segments are substantially the same as those described in Note A. Intersegment gross sales are recorded on the same basis as sales to unaffiliated customers. Intersegment sales for the Marketing and Trading segment were $487.3 million, $299.2 million and $614.7 million for the years ended December 31, 2003, 2002 and 2001, respectively. Energy trading contracts included in the following table are reported net of related costs. Corporate overhead costs relating

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to a reportable segment have been allocated for the purpose of calculating operating income. The Company's equity method investments do not represent operating segments of the Company. The Company has no single external customer from which it receives ten percent or more of its consolidated gross revenues.

The following tables set forth certain selected financial information for the Company's six operating segments for the periods indicated.

Year Ended December 31, 2003	Regulated: Transportation and Storage	Regulated: Distribution	Non-Regulated: Marketing and Trading	Non-Regulated: Gathering and Processing	Non-Regulated: Production	Non-Regulated: Other and Eliminations	Total
	(Thousands of Dollars)						
Sales to unaffiliated customers	**$ 68,724**	**$ 1,740,060**	**$ 91,965**	**$ 1,311,069**	**$ 40,858**	**$ (483,462)**	**$ 2,769,214**
Energy trading contracts, net	**—**	**—**	**229,782**	**—**	**—**	**—**	**229,782**
Intersegment sales	**92,575**	**—**	**—**	**467,448**	**3,130**	**(563,153)**	**—**
Total Revenues	**$ 161,299**	**$ 1,740,060**	**$ 321,747**	**$ 1,778,517**	**$ 43,988**	**$ (1,046,615)**	**$ 2,998,996**
Net revenues	**$ 113,662**	**$ 526,249**	**$ 236,369**	**$ 214,137**	**$ 43,988**	**$ 2,073**	**$ 1,136,478**
Operating costs	**$ 46,186**	**$ 312,814**	**$ 33,699**	**$ 122,103**	**$ 15,812**	**$ (1,061)**	**$ 529,553**
Depreciation, depletion and amortization	**$ 16,694**	**$ 95,654**	**$ 5,708**	**$ 29,332**	**$ 12,070**	**$ 1,403**	**$ 160,861**
Operating income	**$ 50,782**	**$ 117,781**	**$ 196,962**	**$ 62,702**	**$ 16,106**	**$ 1,731**	**$ 446,064**
Income from operations of discontinued component	**$ —**	**$ —**	**$ —**	**$ —**	**$ 2,342**	**$ —**	**$ 2,342**
Cumulative effect of changes in accounting principles, net of tax	**$ (645)**	**$ —**	**$ (141,982)**	**$ (1,375)**	**$ 117**	**$ —**	**$ (143,885)**
Income from equity investments	**$ 1,398**	**$ —**	**$ —**	**$ 55**	**$ —**	**$ 94**	**$ 1,547**
Total assets	**$ 867,743**	**$ 2,462,299**	**$ 1,332,022**	**$ 1,307,445**	**$ 151,575**	**$ 192,964**	**$ 6,314,048**
Capital expenditures (continuing operations)	**$ 15,234**	**$ 153,405**	**$ 555**	**$ 20,598**	**$ 18,655**	**$ 6,701**	**$ 215,148**

Year Ended December 31, 2002	Regulated: Transportation and Storage	Regulated: Distribution	Non-Regulated: Marketing and Trading	Non-Regulated: Gathering and Processing	Non-Regulated: Production	Non-Regulated: Other and Eliminations	Total
	(Thousands of Dollars)						
Sales to unaffiliated customers	$ 70,812	$ 1,218,400	$ 72,697	$ 810,722	$ 29,998	$ (307,778)	$ 1,894,851
Energy trading contracts, net	—	—	209,429	—	—	—	209,429
Intersegment sales	93,422	2,244	—	322,499	2,456	(420,621)	—
Total Revenues	$ 164,234	$ 1,220,644	$ 282,126	$ 1,133,221	$ 32,454	$ (728,399)	$ 2,104,280
Net revenues	$ 117,584	$ 414,393	$ 214,480	$ 194,378	$ 32,454	$ 2,371	$ 975,660
Operating costs	$ 46,694	$ 243,170	$ 27,674	$ 127,747	$ 8,332	$ 2,722	$ 456,339
Depreciation, depletion and amortization	$ 17,563	$ 76,063	$ 5,298	$ 33,523	$ 13,842	$ 1,554	$ 147,843
Operating income	$ 53,327	$ 95,160	$ 181,508	$ 33,108	$ 10,280	$ (1,905)	$ 371,478
Income from operations of discontinued component	$ —	$ —	$ —	$ —	$ 10,648	$ —	$ 10,648
Income from equity investments	$ 1,381	$ —	$ —	$ —	$ —	$ (1,015)	$ 366
Total assets	$ 815,301	$ 1,773,000	$ 1,666,271	$ 1,246,866	$ 348,222	$ (40,066)	$ 5,808,594
Capital expenditures (continuing operations)	$ 20,554	$ 115,569	$ 2,340	$ 43,101	$ 17,810	$ 11,278	$ 210,652
Capital expenditures (discontinued component)	$ —	$ —	$ —	$ —	$ 21,824	$ —	$ 21,824

Year Ended December 31, 2001	Regulated: Transportation and Storage	Regulated: Distribution	Non-Regulated: Marketing and Trading	Non-Regulated: Gathering and Processing	Non-Regulated: Production	Non-Regulated: Other and Eliminations	Total
	(Thousands of Dollars)						
Sales to unaffiliated customers	$ 76,837	$ 1,506,420	$ 29,760	$ 814,963	$ 33,799	$ (647,599)	$ 1,814,180
Energy trading contracts, net	—	—	101,761	—	—	—	101,761
Intersegment sales	86,226	4,548	—	499,854	4,108	(594,736)	—
Total Revenues	$ 163,063	$ 1,510,968	$ 131,521	$ 1,314,817	$ 37,907	$ (1,242,335)	$ 1,915,941
Net revenues	$ 113,437	$ 369,300	$ 110,287	$ 189,621	$ 37,907	$ 5,823	$ 826,375
Operating costs	$ 42,357	$ 237,657	$ 32,846	$ 116,853	$ 8,351	$ (831)	$ 437,233
Depreciation, depletion and amortization	$ 17,990	$ 70,359	$ 2,611	$ 29,201	$ 11,240	$ 2,132	$ 133,533
Operating income	$ 53,090	$ 61,284	$ 74,830	$ 43,567	$ 18,316	$ 4,522	$ 255,609
Income from operations of discontinued component	$ —	$ —	$ —	$ —	$ 24,879	$ —	$ 24,879
Cumulative effect of change in accounting principle, net of tax	$ —	$ —	$ —	$ —	$ (2,151)	$ —	$ (2,151)
Income from equity investments	$ 2,946	$ —	$ —	$ —	$ 111	$ 5,052	$ 8,109
Total assets	$ 723,263	$ 1,762,738	$ 1,491,624	$ 1,303,236	$ 321,720	$ 250,719	$ 5,853,300
Capital expenditures (continuing operations)	$ 32,378	$ 133,470	$ 43,486	$ 51,442	$ 20,429	$ 24,817	$ 306,022
Capital expenditures (discontinued component)	$ —	$ —	$ —	$ —	$ 35,545	$ —	$ 35,545

(P) QUARTERLY FINANCIAL DATA (UNAUDITED)

Total operating revenues are consistently greater during the heating season from November through March due to the large volume of natural gas sold to customers for heating. The following tables set forth the unaudited quarterly results of operations for the periods indicated.

Year Ended December 31, 2003	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(Thousands of Dollars, except per share amounts)			
Net revenues	**$ 402,952**	**$ 232,436**	**$ 194,382**	**$ 306,708**
Operating income	**$ 232,437**	**$ 62,009**	**$ 31,820**	**$ 119,798**
Income from continuing operations	**$ 125,607**	**$ 22,548**	**$ 4,595**	**$ 61,542**
Income from discontinued operations	**$ 2,342**	**$ —**	**$ —**	**$ —**
Gain on sale of discontinued component	**$ 38,369**	**$ —**	**$ —**	**$ 1,370**
Cumulative effect of a change in accounting principle	**$ (143,885)**	**$ —**	**$ —**	**$ —**
Net Income	**$ 22,433**	**$ 22,548**	**$ 4,595**	**$ 62,912**
Earnings per share from continuing operations				
Basic	**$ 1.43**	**$ 0.24**	**$ 0.01**	**$ 0.71**
Diluted	**$ 1.20**	**$ 0.23**	**$ 0.01**	**$ 0.65**

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Year Ended December 31, 2002	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(Thousands of Dollars, except per share amounts)			
Net revenues	$ 294,436	$ 238,637	$ 208,842	$ 233,745
Operating income	$ 141,465	$ 79,291	$ 63,784	$ 86,938
Income from continuing operations	$ 71,693	$ 32,318	$ 17,376	$ 34,589
Income from discontinued operations	$ 905	$ 3,065	$ 3,343	$ 3,335
Net Income	$ 72,598	$ 35,383	$ 20,719	$ 37,924
Earnings per share from continuing operations				
Basic	$ 0.60	$ 0.27	$ 0.15	$ 0.30
Diluted	$ 0.59	$ 0.27	$ 0.15	$ 0.30

In the first quarter of 2002, the Company recovered $14.0 million of charges previously taken related to the Enron bankruptcy filing. In the second quarter of 2002, the Company increased operating income by $14.2 million as a result of a settlement with the OCC related to unrecovered gas costs associated with the 2000/2001 winter. For further discussion of these charges, see Note M.

(Q) SUPPLEMENTAL CASH FLOW INFORMATION

The following tables set forth supplemental information relative to the Company’s cash flows for the periods indicated.

	Years Ended December 31,		
	2003	2002	2001
	(Thousands of Dollars)		
Cash paid during the year			
Interest (including amounts capitalized)	**$100,662**	$109,897	$ 132,364
Income taxes paid (received)	**$ (16,302)**	$ (90,306)	$ 13,050
Noncash transactions			
Cumulative effect of changes in accounting principle			
Rescission of EITF 98-10 (price risk management assets and liabilities)	**$141,832**	$ —	$ —
Adoption of Statement 143	**$ 2,053**	$ —	$ —
Dividends on restricted stock	**$ 279**	$ 209	$ 128
Issuance of restricted stock, net	**$ 3,201**	$ 2,628	$ 1,854
Treasury stock transferred to compensation plans	**$ 4,450**	$ 1,958	$ 1,776

	Years Ended December 31,		
	2003	2002	2001
	(Thousands of Dollars)		
Acquisitions			
Property, plant, and equipment	**$537,855**	$ 4,036	$ 440
Current assets	**70,027**	—	—
Current liabilities	**(60,106)**	—	—
Regulatory assets and goodwill	**116,381**	—	14,500
Lease obligation	**(4,715)**	—	—
Deferred credits	**(22,900)**	—	—
Deferred income taxes	**55,858**	—	—
Cash paid for acquisitions - continuing operations	**$692,400**	$ 4,036	$ 14,940
Cash paid for acquisitions - discontinued operations	**$ —**	$ 764	$ 1,075

(R) STOCK BASED COMPENSATION

Stock Splits - Due to the 2001 stock split, the number of shares and related exercise prices have been adjusted to maintain both the total market value of common stock underlying the options and Employee Stock Purchase Plan (ESPP) share elections, and the relationship between the fair market value of the common stock and the exercise price of the options and ESPP share elections.

Deferred Compensation Plans

Employee Non-Qualified Deferred Compensation Plan - The ONEOK, Inc. Employee Non-Qualified Deferred Compensation Plan provides select employees, as approved by the Board of Directors, with the option to defer portions of their compensation and provides non-qualified deferred compensation benefits which are not available due to limitations on employer and employee contributions to qualified defined contribution plans under the federal tax laws. Under the plan, participants have the option to defer their salary and/or bonus compensation to a short-term deferral account, which pays out a minimum of five years from commencement, or a long-term deferral account, which pays out at retirement or termination of the participant. Participants are immediately 100 percent vested. Short-term deferral accounts are allocated to the Five Year Treasury Bond Fund. Long-term deferral accounts are allocated among various investment options, including the Company's common stock. At the distribution date, cash is distributed to the participants based on the fair market value of the investment at that date.

Deferred Compensation Plan for Non-Employee Directors - The ONEOK, Inc. Deferred Compensation Plan for Non-Employee Directors provides directors of the Company, who are not employees of the Company, the option to defer all or a portion of their compensation for their service on the Company's Board of Directors. Under the plan, directors may elect either a cash deferral option or a phantom stock option. Under the cash deferral option, directors may defer the receipt of all or a portion of their annual retainer and/or meeting fees, plus accrued interest. Under the phantom stock option, directors may defer all or a portion of their annual retainer and/or meeting fees and receive such fees on a deferred basis in the form of shares of common stock under the Company's Long-Term Incentive Plan. Shares are distributed to non-employee directors at the fair market value of the Company's common stock at the date of distribution.

Long-Term Incentive Plan

General - The ONEOK, Inc. Long-Term Incentive Plan provides for the granting of incentive stock options, non-statutory stock options, stock bonus awards, restricted stock awards and performance unit awards to key employees and the granting of stock awards to non-employee directors. The Company has reserved approximately 7.8 million shares of common stock for the plan, less the number of shares previously issued under the plan. The maximum number of shares for which options or other awards may be granted to any employee or non-employee director during any year is 300,000 and 20,000, respectively.

Stock Option Plan for Employees - Under the Long-Term Incentive Plan, options may be granted by the Executive Compensation Committee (the Committee). Stock options and awards may be granted at any time until all shares authorized are transferred, except that no incentive stock option may be granted under the plan after August 17, 2005. Options may be granted which are not exercisable until a fixed future date or in installments. The plan also provides for restored options to be granted in the event an optionee surrenders shares of common stock that the optionee already owns in full or partial payment of the option price of an option being exercised and/or surrenders shares of common stock to satisfy withholding tax obligations incident to the exercise of an option. A restored option is for the number of shares surrendered by the optionee and has an option price equal to the fair market value of the common stock on the date on which the exercise of an option resulted in the grant of the restored option.

Options issued to date become void upon voluntary termination of employment other than retirement. In the event of retirement or involuntary termination, the optionee may exercise the option within three months. In the event of death, the option may be exercised by the personal representative of the optionee within a period to be determined by the Committee and stated in the option. A portion of the options issued to date can be exercised after one year from grant date and an option must be exercised no later than ten years after grant date.

Stock Option Plan for Non-Employee Directors - Under the plan, options may be granted by the Committee at any time on or before January 18, 2011. Options may be exercisable in full at the time of grant or may become exercisable in one or more installments. The plan also provides for restored options consistent with the plan for employees. Options issued to date become void upon termination of service as a Non-Employee Director. Such options must be exercised no later than ten years after the date of grant of the option. In the event of death, the option may be exercised by the personal representative of the optionee.

The following table sets forth the stock option activity for stock options under the Long-Term Incentive Plan for employees and non-employee directors for the periods indicated.

	Number of Shares	Weighted Average Exercise Price
Outstanding December 31, 2000	1,501,356	$ 16.19
Granted	1,102,000	$ 22.43
Exercised	(118,750)	$ 15.27
Expired	(179,672)	$ 19.57
Restored	3,538	$ 22.49
Outstanding December 31, 2001	2,308,472	$ 18.96
Granted	1,028,750	$ 17.06
Exercised	(226,286)	$ 15.64
Expired	(120,211)	$ 19.41
Restored	72,951	$ 21.01
Outstanding December 31, 2002	3,063,676	$ 18.60
Granted	**458,400**	**$ 16.79**
Exercised	**(413,471)**	**$ 16.23**
Expired	**(25,062)**	**$ 20.45**
Restored	**134,146**	**$ 21.33**
Outstanding December 31, 2003	**3,217,689**	**$ 18.75**
Options Exercisable		
December 31, 2001	941,572	$ 16.57
December 31, 2002	1,378,270	$ 18.20
December 31, 2003	**1,651,840**	**$ 18.94**

At December 31, 2003, the Company had 2,254,389 outstanding options with exercise prices ranging between $11.85 to $17.77 and a weighted average remaining life of 7.07 years. Of these options, 1,127,640 were exercisable at December 31, 2003, with a weighted average exercise price of $17.28.

The Company also had 963,300 options outstanding at December 31, 2003, with exercise prices ranging between $17.78 and $33.47 and a weighted average remaining life of 7.02 years. Of these options, 524,200 were exercisable at December 31, 2003, at a weighted average exercise price of $22.52.

Restricted Stock Awards - Under the Long-Term Incentive Plan, restricted stock awards may be granted to key officers and employees with ownership of the common stock vesting over a three-year period. Shares awarded may not be sold during the vesting period. The fair market value of the shares associated with the restricted stock awards is recorded as unearned compensation in shareholders' equity and is amortized to compensation expense over the vesting period. The dividends on the restricted stock awards are reinvested in common stock. The average price of shares granted was $16.88, $17.05 and $22.31 for the years ended December 31, 2003, 2002 and 2001, respectively.

Restricted stock information has been restated to give effect to the 2001 two-for-one stock split. The following table sets forth the restricted stock activity for the periods indicated.

	Number of Shares	Weighted Average Exercise Price
Outstanding December 31, 2000	114,814	$ 14.55
Granted	90,400	$ 22.31
Released to participants	(2,424)	$ 14.70
Forfeited	(6,676)	$ 14.70
Dividends	6,463	$ 19.52
Outstanding December 31, 2001	202,577	$ 18.17
Granted	156,300	$ 17.05
Released to participants	(107,547)	$ 17.73
Forfeited	(1,912)	$ 18.77
Dividends	10,436	$ 19.92
Outstanding December 31, 2002	259,854	$ 17.74
Granted	**189,900**	**$ 16.88**
Released to participants	**(4,417)**	**$ 13.70**
Forfeited	**(2,686)**	**$ 19.15**
Dividends	**14,109**	**$ 19.48**
Outstanding December 31, 2003	**456,760**	**$ 17.47**

Performance Share Awards - Under the Long-Term Incentive Plan, performance share awards may be granted to key officers and employees. The performance shares vest at the expiration of a three-year period after the grant date if certain performance criteria are met by the Company. Performance share units are not common stock, but may be converted into common stock if the performance criteria are met. The value of the units associated with the performance shares awards is recorded as unearned compensation in shareholders’ equity and is amortized to compensation expense over the vesting period. During 2003, the Company granted 172,900 performance share awards at a price of $16.88 per share. There were no performance share awards released to participants or forfeited during 2003.

Employee Stock Purchase Plan - The ESPP currently has 2.8 million shares reserved, less the number of shares issued to date under this plan. Subject to certain exclusions, all full-time employees are eligible to participate. Under the terms of the plan, employees can choose to have up to ten percent of their annual earnings withheld to purchase the Company’s common stock. The Committee may allow contributions to be made by other means provided that in no event will contributions from all means exceed ten percent of the employee’s annual earnings. The purchase price of the stock is 85 percent of the lower of its grant date or exercise date market price. Approximately 58 percent, 61 percent, and 56 percent of eligible employees participated in the plan in fiscal years 2003, 2002, and 2001, respectively. Under the plan, the Company sold 296,125 shares in 2003, 285,200 shares in 2002, and 192,593 shares in 2001.

Accounting Treatment - The Company applied APB 25 in accounting for the plans through 2002. Accordingly, no compensation cost was recognized in the consolidated financial statements for the Company’s stock options and the ESPP in 2002 or 2001. The Company adopted Statement 148 on January 1, 2003, and began expensing the fair value of all stock options granted on or after January 1, 2003. See Note A for disclosure of the Company’s pro forma net income and earnings per share information had the Company applied the provisions of Statement 123 to determine the compensation cost under these plans for stock options granted prior to January 1, 2003 for the periods presented.

The fair market value of each option granted was estimated on the date of grant based on the Black-Scholes model using the following assumptions: volatility of 30.3 percent for 2003, 22.1 percent for 2002, and 21.1 percent for 2001; dividend yield of 3.5 percent for 2003, 3.6 percent for 2002, and 5.5 percent for 2001; and risk-free interest rate of 4.0 percent for 2003, 5.1 percent for 2002, and 5.2 percent for 2001.

Expected life ranged from 1 to 10 years based upon experience to date and the make-up of the optionees. Fair value of options granted at fair market value under the Plan were $4.67, $3.88 and $3.17 for the years ended December 31, 2003, 2002 and 2001, respectively. Fair value of options granted above fair market value under the Plan was $3.50 for the year ended December 31, 2001. The average exercise price of options granted above fair market value is $23.49 for the year ended December 31, 2001.

(S) EARNINGS PER SHARE INFORMATION

Through February 5, 2003, the Company computed its EPS in accordance with Topic D-95. In accordance with Topic D-95, the dilutive effect of the Company's Series A Convertible Preferred Stock was considered in the computation of basic EPS utilizing the "if-converted" method. Under the Company's "if-converted" method, the dilutive effect of the Company's Series A Convertible Preferred Stock on EPS could not be less than the amount that would have resulted from the application of the "two-class" method of computing EPS. The "two-class" method is an earnings allocation formula that determined EPS for the Company's common stock and its participating Series A Convertible Preferred Stock according to dividends declared and participating rights in the undistributed earnings. The Company's Series A Convertible Preferred Stock was a participating instrument with the Company's common stock with respect to the payment of dividends. For the years ended December 31, 2001 and 2002, and the period from January 1, 2003 to February 5, 2003, the "two-class" method resulted in additional dilution. Accordingly, EPS for this period reflects this further dilution. As a result of the Company's repurchase and exchange of its Series A Convertible Preferred Stock in February 2003, the Company no longer applied the provisions of Topic D-95 to its EPS computations beginning in February 2003.

The following table sets forth the computation of basic and diluted earnings per share from continuing operations for the periods indicated.

	Year Ended December 31, 2003		
	Income	**Shares**	**Per Share Amount**
	(Thousands, except per share amounts)		
Basic EPS from continuing operations			
Income from continuing operations available for common stock under D-95	$ 26,174	62,055	
Series A Convertible Preferred Stock dividends	12,139	39,893	
Income from continuing operations available for common stock and assumed conversion of Series A Convertible Preferred Stock	38,313	101,948	$ 0.37
Further dilution from applying the "two-class" method			$ (0.08)
Basic EPS from continuing operations under D-95			$ 0.29
Income from continuing operations available for common stock not under D-95	163,907	78,585	$ 2.09
Basic EPS from continuing operations			**$ 2.38**
Diluted EPS from continuing operations			
Income from continuing operations available for Series D Convertible Preferred Stock dividends	202,220	80,569	
Effect of other dilutive securities:			
Options and other dilutive securities	—	911	
Series D Convertible Preferred Stock dividends	12,072	15,519	
Income from continuing operations	$ 214,292	96,999	$ 2.21
Further dilution from applying the "two-class" method			$ (0.08)
Diluted EPS from continuing operations			**$ 2.13**

	Year Ended December 31, 2002		
	Income	Shares	Per Share Amount
	(Thousands, except per share amounts)		
Basic EPS from continuing operations			
Income from continuing operations available for common stock	$ 118,876	60,022	
Convertible preferred stock	37,100	39,892	
Income from continuing operations available for common stock and assumed conversion of preferred stock	155,976	99,914	$ 1.56
Further dilution from applying the "two-class" method			(0.25)
Basic EPS from continuing operations			$ 1.31
Effect of other dilutive securities			
Options and other dilutive securities	—	614	
Diluted EPS from continuing operations			
Income from continuing operations available for common stock and assumed exercise of stock options	$ 155,976	100,528	$ 1.55
Further dilution from applying the "two-class" method			(0.25)
Diluted EPS from continuing operations			$ 1.30

	Year Ended December 31, 2001		
	Income	Shares	Per Share Amount
	(Thousands, except per share amounts)		
Basic EPS from continuing operations			
Income from continuing operations available for common stock	$ 41,737	59,557	
Convertible preferred stock	37,100	39,892	
Income from continuing operations available for common stock and assumed conversion of preferred stock	78,837	99,449	$ 0.79
Further dilution from applying the "two-class" method			(0.13)
Basic EPS from continuing operations			$ 0.66
Effect of other dilutive securities			
Options and other dilutive securities	—	222	
Diluted EPS from continuing operations			
Income from continuing operations available for common stock and assumed exercise of stock options	$ 78,837	99,671	$ 0.79
Further dilution from applying the "two-class" method			(0.13)
Diluted EPS from continuing operations			$ 0.66

There were 151,448, 167,116, and 158,989 option shares excluded from the calculation of diluted earnings per share for the years ended December 31, 2003, 2002 and 2001, respectively, since their inclusion would be antidilutive for each period.

The repurchase and exchange of the Company's Series A Convertible Preferred Stock from Westar in February 2003 was recorded at fair value. In accordance with EITF Topic No. D-42, the premium, or the excess of the fair value of the consideration transferred to Westar over the carrying value of the Series A Convertible Preferred Stock, was considered a preferred dividend. The premium recorded on the repurchase and exchange of the Series A Convertible Preferred Stock was approximately $44.2 million and $53.4 million, respectively, for a total premium of $97.6 million. As a result of the Company's adoption of Topic D-95, the Company recognized additional dilution of approximately $94.5 million through the application of the "two-class" method of computing EPS. This additional dilution offsets the total premium recorded, resulting in a net premium of $3.1 million, which is reflected as a dividend on the Series A Convertible Preferred Stock in the EPS calculation above for the year ended December 31, 2003.

(T) OIL AND GAS PRODUCING ACTIVITIES

The following table sets forth the Company's historical cost information relating to its production operations for the periods indicated.

	Continuing Operations Years Ended December 31,			Discontinued Component Years Ended December 31,		
	2003	**2002**	**2001**	**2003**	**2002**	**2001**
			(Thousands of Dollars)			
Capitalized costs at end of year						
Unproved properties	**$ 461**	$ 409	$ 424	**$ —**	$ 7,073	$ 3,799
Gathering system	**15,250**	—	—	**—**	—	—
Proved properties (1)	**385,566**	143,492	122,345	**—**	364,461	355,643
Total capitalized costs	**401,277**	143,901	122,769	**—**	371,534	359,442
Accumulated depreciation, depletion and amortization	**61,725**	58,383	44,761	**—**	148,798	134,320
Net capitalized costs	**$ 339,552**	$ 85,518	$ 78,008	**$ —**	$ 222,736	$ 225,122
Costs incurred during the year						
Property acquisition costs (unproved)	**$ 212**	$ 326	$ 792	**$ —**	$ 4,118	$ 1,542
Exploitation costs	**$ —**	$ —	$ 8	**$ —**	$ —	$ —
Development costs	**$ 18,472**	$ 15,336	$ 19,216	**$ —**	$ 19,809	$ 34,004
Purchase of minerals in place	**$ 240,512**	$ 2,899	$ 1,244	**$ —**	$ 764	$ 328

(1) Proved properties includes $5.1 million for asset retirement obligations capitalized as additional costs per Statement 143.

The following table sets forth the results of the Company's oil and gas producing operations for the periods indicated. The results exclude general office overhead and interest expense attributable to oil and gas production.

	Continuing Operations Years Ended December 31,			Discontinued Component Years Ended December 31,		
	2003	**2002**	**2001**	**2003**	**2002**	**2001**
			(Thousands of Dollars)			
Net revenues						
Sales to unaffiliated customers	**$ 40,178**	$ 29,890	$ 33,752	**$ 7,524**	$ 50,354	$ 60,183
Gas sold to affiliates	**2,860**	2,456	4,108	**217**	13,190	22,065
Net revenues from production	**43,038**	32,346	37,860	**7,741**	63,544	82,248
Production costs	**8,407**	6,158	6,926	**1,186**	13,346	14,073
Depreciation, depletion and amortization	**11,475**	12,668	10,701	**1,937**	24,836	23,777
Taxes	**8,298**	5,230	7,826	**1,477**	9,810	17,173
Total expenses	**28,180**	24,056	25,453	**4,600**	47,992	55,023
Results of operations from producing activities	**$ 14,858**	$ 8,290	$ 12,407	**$ 3,141**	$ 15,552	$ 27,225

(U) OIL AND GAS RESERVES (UNAUDITED)

The Company emphasizes that the volumes of reserves shown are estimates, which, by their nature, are subject to later revision. The estimates are made by the Company utilizing all available geological and reservoir data as well as production performance data. These estimates are reviewed annually both internally and by an independent reserve engineer, Ralph E. Davis and Associates, and revised, either upward or downward, as warranted by additional performance data.

The following table sets forth estimates of the Company's proved oil and gas reserves, net of royalty interests and changes herein, for the periods indicated.

	Continuing Operations		Discontinued Component	
	Oil *(MBbls)*	Gas *(MMcf)*	Oil *(MBbls)*	Gas *(MMcf)*
December 31, 2000	2,302	73,892	2,037	180,829
Revisions in prior estimates	(285)	(8,190)	(252)	(20,043)
Extensions, discoveries and other additions	636	9,688	562	23,709
Purchases of minerals in place	2	272	1	664
Sales of minerals in place	—	(80)	—	(196)
Production	(261)	(8,000)	(231)	(19,578)
December 31, 2001	2,394	67,582	2,117	165,385
Revisions in prior estimates	(399)	(9,242)	781	19,520
Extensions, discoveries and other additions	690	9,910	120	10,868
Purchases of minerals in place	49	869	10	197
Sales of minerals in place	—	(1)	—	(106)
Production	(273)	(7,370)	(241)	(18,036)
December 31, 2002	2,461	61,748	2,787	177,828
Revisions in prior estimates	**(720)**	**(3,832)**	—	—
Extensions, discoveries and other additions	**337**	**12,926**	—	—
Purchases of minerals in place	**2,314**	**157,763**	—	—
Sales of minerals in place	—	—	**(2,734)**	**(176,356)**
Production	**(265)**	**(7,486)**	**(53)**	**(1,472)**
December 31, 2003	**4,127**	**221,119**	—	—
Proved developed reserves				
December 31, 2001	1,445	46,915	1,278	114,810
December 31, 2002	1,521	40,230	2,001	128,778
December 31, 2003	**2,070**	**132,451**	—	—

(V) DISCOUNTED FUTURE NET CASH FLOWS (UNAUDITED)

The following table sets forth estimates of the standard measure of discounted future cash flows from proved reserves of oil and natural gas for the periods indicated.

	Continuing Operations Years Ended December 31,			Discontinued Component Years Ended December 31,		
	2003	2002	2001	2003	2002	2001
	(Thousands of Dollars)					
Future cash inflows	**$ 1,453,999**	$ 365,637	$ 195,871	**$ —**	$ 883,816	$ 473,457
Future production costs	**269,779**	70,574	52,024	—	173,299	112,145
Future development costs	**94,579**	20,934	11,787	—	23,067	24,785
Future income taxes	**298,229**	93,415	36,199	—	224,756	83,665
Future net cash flows	**791,412**	180,714	95,861	—	462,694	252,862
10 percent annual discount for estimated timing of cash flows	**400,407**	77,736	40,008	—	205,411	109,093
Standardized measure of discounted future net cash flows relating to oil and gas reserves	**$ 391,005**	$ 102,978	$ 55,853	**$ —**	$ 257,283	$ 143,769

Future cash inflows are computed by applying year-end prices (averaging $29.78 per barrel of oil, adjusted for transportation and other charges, and $5.98 per Mcf of gas at December 31, 2003) to the year-end quantities of proved reserves. As of December 31, 2003, a portion of proved developed gas production for continuing operations in 2004 has been hedged. The effects of these hedges are not reflected in the computation of future cash flows above. If the effects of the hedges had been included, the future cash inflows would have decreased by approximately $9.6 million.

These estimated future cash flows are reduced by estimated future development and production costs based on year-end cost levels, assuming continuation of existing economic conditions, and by estimated future income tax expense. The tax expense is calculated by applying the current year-end statutory tax rates to pretax net cash flows (net of tax depreciation, depletion, and lease amortization allowances) applicable to oil and gas production.

The following table sets forth the changes in standardized measure of discounted future net cash flow relating to proved oil and gas reserves for the periods indicated.

	Continuing Operations Years Ended December 31,			Discontinued Component Years Ended December 31,		
	2003	**2002**	**2001**	**2003**	**2002**	**2001**
			(Thousands of Dollars)			
Beginning of period	**$ 102,978**	$ 55,853	$ 219,103	**$ 257,283**	$ 143,769	$ 536,780
Changes resulting from:						
Sales of oil and gas produced, net of production costs	**(34,631)**	(26,199)	(30,942)	**(3,818)**	(50,198)	(68,175)
Net changes in price, development, and production costs	**7,086**	62,196	(300,373)	**—**	133,586	(578,330)
Development costs incurred	**18,472**	15,336	23,223	**—**	19,809	29,997
Extensions, discoveries, additions, and improved recovery, less related costs	**61,718**	31,759	25,209	**—**	31,676	25,144
Purchases of minerals in place	**363,367**	2,899	468	**—**	764	1,104
Sales of minerals in place	**—**	(1)	(7)	**(253,465)**	(322)	(2,240)
Revisions of previous quantity estimates	**(14,796)**	(23,291)	(42,858)	**—**	49,513	(93,313)
Accretion of discount	**19,512**	7,749	33,777	**—**	19,042	82,999
Net change in income taxes	**(94,646)**	(31,583)	99,617	**—**	(77,951)	245,868
Other, net	**(38,055)**	8,260	28,636	**—**	(12,405)	(36,065)
End of period	**$ 391,005**	$ 102,978	$ 55,853	**$ —**	$ 257,283	$ 143,769

(W) SUBSEQUENT EVENTS (UNAUDITED)

2004 Common Stock Offering - During the first quarter of 2004, the Company sold 6.9 million shares of its common stock to an underwriter at $21.93 per share, resulting in proceeds to the Company, before expenses, of $151.3 million.

Related Party Transactions - In January 2004, the Company elected Julie H. Edwards, Executive Vice President – Finance and Administration and Chief Financial Officer for Frontier Oil Corporation and its subsidiaries (Frontier), to the board of directors. From time to time and in the normal course of business, the Company purchases natural gas liquids from and sells natural gas and natural gas liquids and provides natural gas transportation services to Frontier. The purchase and sales transactions are conducted under substantially the same terms as comparable third-party transactions.

In January 2004, the Company's transactions with the Williford Companies increased substantially. Mollie Williford, Chairman of the Board of the Williford Companies, which consists of numerous companies including Williford Energy Company and TriCounty Gas Processors, Inc., is a member of the Company's board of directors. In the normal course of business, the Company conducts natural gas and natural gas liquids purchase and sale transactions with Williford Energy Company and TriCounty Gas Processors, Inc. These transactions are conducted under substantially the same terms as comparable third-party transactions. All related party transactions with the Williford Companies prior to 2004 were immaterial.

Acquisition of Gulf Coast Fractionators - On February 25, 2004, the Company announced an agreement with ConocoPhillips to purchase a 22.5 percent general partnership interest in Gulf Coast Fractionators (GFC), which owns a natural gas liquids fractionation facility, located in Mont Belvieu, Texas for $23 million, subject to adjustments. The pending acquisition is subject to the customary closing conditions, the consent of the partners, and agreement by the partners that we will replace ConocoPhillips as operator of the facility. By existing agreement, the GFC partners have a preferential right to purchase the ConocoPhillips interest at the same terms as agreed to by the Company. This preferential right expires March 31, 2004. This facility has a fractionation capacity of 110 MBbls/d of mixed NGLs. As the operator, the Company will operate the facility and control approximately 24.8 MBbls/d of fractionation capacity. The acquisition is expected to close in April 2004 and is estimated to add $1.8 million to operating income in 2004.

Sale of Transmission and Gathering Pipelines and Compression - On March 1, 2004, we completed a transaction to sell certain natural gas transmission and gathering pipelines and compression for approximately $13 million.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

After initially filing our annual report on Form 10-K for the period ended December 31, 2003, we responded to a SEC request to supplementally provide the staff of the SEC with additional information about our consolidated statements of cash flows. In the process of preparing this supplemental information, we and our independent auditors became aware of potential misclassifications in the consolidated statements of cash flows that resulted in the overstatement of certain amounts in cash flows from investing or financing activities and an understatement of cash flows from operating activities in identical amounts.

Upon discovering the misclassifications, we immediately contacted our Audit Committee and our internal and outside counsel, as well as the underwriters on our common stock offering and their counsel. After extensive discussions, we promptly issued a press release and filed a current report on Form 8-K to disclose the potential misclassifications and the possibility that we might file an amended Form 10-K to correct the misclassifications. We also promptly notified the staff of the SEC of the potential misclassifications. Upon reaching a final conclusion that there were misclassifications in the consolidated statements of cash flows, we issued a second press release more specifically addressing the changes to our consolidated statements of cash flows, and we are also filing this amended Form 10-K which includes an amended consolidated statements of cash flows.

We believe that the misclassifications were the result of inadvertent human error and do not reflect any weakness in our disclosure controls and procedures. Under the supervision and with the participation of management, including our chief executive officer and our chief financial officer, we have evaluated the effectiveness of the design and operation of our disclosure controls and procedures as defined in Rule 13a-15 of the Securities Exchange Act of 1934. These controls and procedures are designed to ensure that material information relating to the Company and its subsidiaries is communicated to the chief executive officer and the chief financial officer. Based on our evaluation, our chief executive officer and chief financial officer concluded that, as of December 31, 2003 and the date of this amendment, our disclosure controls and procedures are effective to ensure that information required to be disclosed by us in reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms.

There were no changes in our internal controls over financial reporting during the fourth quarter ended December 31, 2003 or in the first quarter of 2004 as of the date of this amendment that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

DIRECTORS OF THE COMPANY

Mollie Hale Carter, age 41, has served as our director since June of 2003. Her current term as a Class III director expires in 2005. **Employment Experience:** Ms. Carter has been vice president of Star A, Inc. since 1997, a family owned company with Kansas agricultural and other investment interests. Previously, she worked for ten years as a senior investment officer at John Hancock Mutual Life Insurance Company. **Directorships:** Ms. Carter is a director of Archer-Daniels-Midland Company and Foley Equipment Company. She is also a trustee of the Rural School and Community Trust.

Charles Q. Chandler, IV, age 50, has served as our director since December of 1999 and chairman of our board since December of 2002. His current term as a Class I director expires in 2006. **Employment Experience:** Mr. Chandler has been chief executive officer of INTRUST Bank, N.A. since 1996 and president of INTRUST Financial Corporation since 1990. Both companies are financial institutions located in Wichita, Kansas. Previously, Mr. Chandler served in various executive capacities at those companies beginning in 1977. **Directorships:** Mr. Chandler is chairman of the board of INTRUST Bank, N.A. and a director of INTRUST Financial Corporation, the First National Bank of Pratt, Kansas, and the Wesley Medical Center in Wichita, Kansas. He is also a trustee of the Kansas State University Endowment Foundation and chairman of the Wichita Collegiate School Board.

R. A. Edwards, age 58, has served as our director since October of 2001. His current term as a Class I director expires in 2006. **Employment Experience:** Mr. Edwards is the president and chief executive officer of the First National Bank of Hutchinson, a financial institution located in Hutchinson, Kansas. **Directorships:** Mr. Edwards is a director of First National Bank of Hutchinson, Douglas County Bank, First Kansas Bancshares of Hutchinson, Data Center, Inc. and Mitchellhill Seed Company, and serves as an advisory director of Kansas Natural Gas, Inc. He is a trustee of the University of Kansas Endowment Association, the Davis Foundation, the Hutchinson Community College Foundation and the Eisenhower Foundation.

James S. Haines, Jr., age 57, has served as our director, chief executive officer and president since December of 2002. His current term as a Class III director expires in 2005. **Employment Experience:** Mr. Haines became our chief executive officer and president in December of 2002. Mr. Haines is an adjunct professor and the Skov Professor of Business Ethics at the University of Texas at El Paso, a position he has held since January of 2002. From May 1996 to November 2001, Mr. Haines was president and chief executive officer of El Paso Electric Company, a public utility company located in El Paso, Texas. Between 1976 and 1996, Mr. Haines served in various executive positions for Westar Energy, Inc. and Kansas Gas and Electric Company.

B. Anthony Isaac, age 51, has served as our director since December of 2003. His current term as a Class II director expires in 2004. **Employment Experience:** Since 2000, Mr. Isaac has been president of LodgeWorks, L.P., a hotel management and development company based in Wichita, Kansas. Before helping to found LodgeWorks, Mr. Isaac served as president of the All-Suites Division of Wyndham Hotels and Resorts from 1998 to 2000. Previously, Mr. Isaac had served in various executive positions within the hotel industry for seventeen years. **Directorships:** Mr. Isaac is a director and secretary of the Via Christi Regional Medical Center in Wichita, Kansas, and also serves as a trustee for the Wichita Collegiate School Board.

Arthur B. Krause, age 62, has served as our director since June of 2003. His current term as a Class III director expires in 2005. **Employment Experience:** Mr. Krause retired in 2002 as executive vice president and chief financial officer of Sprint Corporation, a global communications company, after serving in that position since 1988. Previously, he had served in various management and executive positions within the communications industry for twenty-two years. **Directorships:** Mr. Krause is a director for Call-Net Enterprises, a Canadian telecommunications company, and for the managing general partner of Inergy L.P., a propane gas marketing and distribution business in Kansas City, Missouri. He is also a trustee for the Kansas City Symphony.

Michael F. Morrissey, age 61, has served as our director since April of 2003. His current term as a Class II director expires in 2004. **Employment Experience:** Mr. Morrissey retired in September of 1999 after serving since 1985 as a managing partner of Ernst & Young LLP, an auditing and financial services firm. Mr. Morrissey had served in various other positions with Ernst & Young since 1985, and prior to joining Ernst & Young in 1975, he held various positions from 1970 to 1975 at Deloitte & Touche, an auditing and financial services firm. **Directorships:** Mr. Morrissey is a director and chairman of the audit committees of the general partner of Ferrelgas Partners, L.P., a propane gas marketing and distribution business in Liberty, Missouri, and Dunn Industries, Inc., a construction business in Kansas City, Missouri. Mr. Morrissey is also special advisor to the audit committee of Dairy Farmers of America, a milk marketing dairy cooperative business in Kansas City, Missouri.

John C. Nettels, Jr., age 47, has served as our director since March of 2000. His current term as a Class II director expires in 2004. **Employment Experience:** Mr. Nettels has been a partner of the law firm of Stinson Morrison Hecker, LLP, located in Overland Park, Kansas, since 1994. He was an associate with the Morrison & Hecker LLP law firm from 1985 to 1994.

CORPORATE GOVERNANCE GUIDELINES

We have adopted corporate governance guidelines that address a number of key issues and functions that significantly impact our corporate governance, including director qualifications and responsibilities, responsibilities of key committees of our board of directors, director access to management and independent advisors, director compensation, director orientation and continuing education and meetings of non-management directors. Our Corporate Governance Guidelines are posted on our website at www.wr.com and will be made available in print to any shareholder requesting it from us. The information contained on our website is not part of this document.

COMMITTEE CHARTERS

Our board of directors has adopted a charter for each of the following key committees of the board of directors: the Audit Committee, the Compensation Committee, the Finance Committee and the Nominating and Corporate Governance Committee. These charters set forth the purpose of the committee, the membership of the committee, the scope of the committee’s responsibilities and authority, certain procedural matters regarding the committee and address other matters important to the proper functioning of these key committees. These charters are posted on our website at www.wr.com and will be made available in print to any shareholder requesting it from us. The information contained on our website is not part of this document.

EXECUTIVE OFFICERS OF THE COMPANY

The information regarding our executive officers is included under the caption “Executive Officers of the Company” in Part I, Item 1 above and is incorporated herein by reference.

SECTION 16(A) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE

The rules of the Securities and Exchange Commission require our directors and executive officers to file reports of their holdings and transactions in our common stock. Based solely on our review of the reports filed under Section 16(a) of the Exchange Act and written representations that no other reports were required, we believe that, during the fiscal year ended December 31, 2003, all required filings applicable to our executive officers, directors and owners of more than ten percent of our common stock were made and that such persons were in compliance with the Exchange Act requirements.

CODE OF ETHICS

We have adopted a code of ethics that applies to all of our employees, including our chief executive officer, chief financial officer, chief operating officer and controller. Our Code of Business Conduct and Ethics is posted on our website at www.wr.com. We intend to post on our website any amendments to, or waivers from, our Code of Business Conduct and Ethics within five business days of the date of any amendment or waiver. The information contained on our website is not part of this document.

AUDIT COMMITTEE FINANCIAL EXPERT

We have an Audit Committee whose members are Michael F. Morrissey, R. A. Edwards and Arthur B. Krause. Each member of the Audit Committee is independent, as defined by New York Stock Exchange rules. Michael F. Morrissey is the Chairman of the Audit Committee. The board of directors has determined that Michael F. Morrissey is our financial expert as defined in applicable SEC rules.

ITEM 11. EXECUTIVE COMPENSATION

COMPENSATION OF DIRECTORS

In 2003, directors who were not our employees received the following compensation:

Annual cash retainer, paid quarterly	$ 20,000
Annual stock award	$ 18,500
Annual restricted share unit award, vesting ratably over three years	$ 19,000
Attendance fee for each meeting of the Board of Directors	$ 1,200
Attendance fee for each committee meeting	$ 1,000
Annual cash fee for Chairman of each committee	$ 4,000
Fee for telephonic attendance at meetings	$ 500

Directors are also reimbursed for travel and other out-of-pocket expenses incurred by them which are incidental to attending meetings. Directors who are our employees do not receive additional compensation for their services as a director.

Pursuant to our Outside Directors’ Deferred Compensation Plan (the “Deferred Compensation Plan”), an outside director may elect to defer all or a portion of any fee received for services. The Deferred Compensation Plan is a voluntary participation plan administered by the Compensation Committee of our Board of Directors. In addition, an outside director may elect to have all or a portion of any cash fee paid in stock pursuant to our Long Term Incentive and Share Award Plan.

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COMPENSATION OF EXECUTIVE OFFICERS

The following table sets forth the compensation of certain executive officers (the "named executive officers") for the last three completed fiscal years:

Summary Compensation Table

		Annual Compensation			Long Term Compensation Award	
Name and Principal Position	**Year**	**Salary $(1)**	**Bonus $**	**Other Annual Compensation $(2)**	**Restricted Stock Awards $(3)**	**All Other Compensation $(4)**
James S. Haines, Jr.	2003	750,000	—	—	—	141,583
Chief Executive Officer and President	2002	50,000	50,000	—	2,902,500	68,795
William B. Moore	2003	400,000	—	53	—	170,011
Executive Vice President and Chief Operating Officer	2002	9,722	—	18,367	1,542,750	171,884
Douglas R. Sterbenz	2003	302,037	—	1,193	1,757,500	6,467
Senior Vice President, Generation and Marketing	2002	359,100	306,757	1,500	765,270	2,615
	2001	190,963	150,256	22,080	24,200	5,287
Mark A. Ruelle	2003	265,625	—	—	1,306,250	60,150
Executive Vice President and Chief Financial Officer						
Richard A. Dixon (5)	2003	214,895	—	141	—	6,012
Former Senior Vice President, Operations Strategy	2002	188,300	119,297	177	241,959	3,235
	2001	144,251	35,000	31,598	77,440	3,033
Larry D. Irick	2003	172,627	—	—	726,300	3,946
Vice President, General Counsel and Corporate	2002	147,300	58,520	—	98,635	3,516
Secretary	2001	127,717	23,000	267	77,440	3,390

(1) Salary in 2003 includes discretionary officer allowances paid to some of our named executive officers (Mr. Sterbenz, $9,000; Mr. Dixon, $6,000; and Mr. Irick, $4,000). Discretionary allowances were paid in 2002 and in the first quarter of 2003 and then discontinued. Discretionary officer allowances replaced car allowances and reimbursements for various expenses provided prior to 2002.

(2) Other annual compensation in 2003 consists of the value of discounts received on shares purchased through the reinvestment of dividends paid on shares held under a stock for compensation program that has been discontinued.

(3) In 2003, we awarded restricted share units linked to shares of our common stock. The reported dollar value of restricted share units is equal to the total number of restricted share units granted to the named executive officer multiplied by the closing price of our common stock on the date of grant. Grants occurred on various dates. This value may not represent the ultimate value of the restricted share units to the officer or us since the value of our common stock is subject to change. Restricted share units awarded to the named executive officers vest ratably in equal increments over a period of three to four years and require the continued employment of the officer until vesting unless the officer's employment is terminated by us without cause, or by the officer for good reason or within 90 days following a change of control. Dividend equivalents are paid on restricted share units from the date of grant in an amount equal to the dividends paid on an equal number of shares of our common stock from the date of grant. See "Employment Contracts" and "Compensation Report" for additional information about restricted share unit awards.

The aggregate number of restricted share units linked to shares of our common stock held by each of the named executive officers as of December 31, 2003, the market value of these restricted share units as of that date and the dividend equivalents received by each of the named executive officers in 2003 with respect to restricted share units linked to our common stock are indicated in the table below. The market value is based on the closing price of our common stock on December 31, 2003 of $20.25 per share.

Name	Restricted Share Units	Market Value ($)	Dividend Equivalents ($)
James S. Haines, Jr.	187,500	3,796,875	217,500
William B. Moore	152,282	3,083,711	91,236
Douglas R. Sterbenz	129,660	2,625,615	65,651
Mark A. Ruelle	125,000	2,531,250	71,250
Richard A. Dixon	8,700	176,175	17,080
Larry D. Irick	57,800	1,170,450	27,097

In 2002, we awarded restricted share units linked to shares of Guardian International, Inc. ("Guardian") preferred stock to Mr. Sterbenz, Mr. Irick and other executive officers. The aggregate number of Guardian restricted share units held by Mr. Sterbenz and Mr. Irick as of December 31, 2003, the market value of these Guardian restricted share units as of that date and the dividend equivalents received by Mr. Sterbenz and Mr. Irick in 2003 with respect to Guardian restricted share units are indicated in the table below. The market value as of December 31, 2003 is based on an appraised value as of September 30, 2003 of $803 per share of Guardian Series C preferred stock, $381 per share of Guardian Series D preferred stock and $623 per share of Guardian Series E preferred stock.

Name	Guardian Restricted Share Units	Market Value ($)	Dividend Equivalents ($)
Douglas R. Sterbenz	872	562,818	50,610
Larry D. Irick	178	84,120	3,570

(4) As set forth below, all other compensation for 2003 includes company matching contributions under our 401(k) savings plan, premiums paid on term life insurance policies, and relocation benefits paid to Mr. Haines and Mr. Ruelle. See "Employment Contracts" for additional information about the relocation benefits.

Name	401(k) Plan ($)	Life Insurance ($)	Relocation ($)
James S. Haines, Jr.	6,000	4,406	62,382
William B. Moore	5,000	1,242	—
Douglas R. Sterbenz	6,000	467	—
Mark A. Ruelle	6,000	421	53,728
Richard A. Dixon	5,061	951	—
Larry D. Irick	3,645	301	—

In addition, all other compensation for 2003 includes payments received by Mr. Haines and Mr. Moore of $68,795 and $163,769, respectively, pursuant to our executive salary continuation plan in connection with previous periods of employment. See "Retirement Plans" for additional information about the executive salary continuation plan.

(5) Mr. Dixon retired from his position as senior vice president with the company on December 31, 2003.

COMPENSATION PLANS

Shares Authorized for Issuance Under Equity Compensation Plans

The following table summarizes the total shares of our common stock that may be received by holders of restricted share units and options upon the vesting of restricted share units and the exercise of currently outstanding options, the weighted average exercise price of those outstanding options and the number of shares of our common stock that are still available for future issuance under our equity compensation plans after considering the restricted share units and stock options currently outstanding.

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Equity Compensation Plan Information

Plan category	Number of shares to be issued upon exercise of outstanding options, warrants and rights	Weighted average exercise price of outstanding options, warrants and rights	Number of shares remaining available for future issuance
Long Term Incentive and Share Award Plan (the only equity compensation plan approved by our shareholders)	2,154,204(1)	32.26 (2)	1,095,785
Any equity compensation plans not approved by our shareholders	—	—	—
Total	2,154,204	32.26	1,095,785

(1) Includes 1,927,546 shares issuable with respect to restricted share units.
(2) Excludes restricted share units referred to in footnote (1) above.

Retirement Plans

We maintain a qualified non-contributory defined benefit plan for all of our non-union employees, including the named executive officers. Participants become fully vested in their benefits under the plan after five years of credited service. Employees hired prior to January 1, 2002, including the named executive officers, are covered by the plan with benefits derived from a final average pay formula. Mr. Haines, Mr. Moore and Mr. Ruelle have vested benefits calculated under the final average pay formula portion of the plan as a result of their prior employment. Mr. Sterbenz, Mr. Irick and other executive officers are accruing benefits under the final average pay formula portion of the plan as a result of their current employment. Mr. Dixon ceased accruing benefits under the final average pay formula portion of the plan upon his retirement.

Employees hired after December 31, 2001 are covered by the same defined benefit plan with benefits derived from a cash balance account formula. Mr. Haines, Mr. Moore and Mr. Ruelle are currently participants in the cash balance formula portion of the plan as a result of their current employment.

The following table sets forth the estimated annual retirement benefits payable to the participants receiving benefits under the final average pay formula portion of the defined benefit plan based upon specified remuneration at age 65 and specified years of service.

Pension Plan Table

	Years of Service				
Remuneration	15	20	25	30	35
$150,000	$39,973	$53,297	$61,372	$69,446	$ 77,520
$175,000	$47,098	$62,797	$72,372	$81,946	$ 91,520
$200,000	$54,223	$72,297	$83,372	$94,446	$105,520
$225,000	$55,648	$74,197	$85,572	$96,946	$108,320
$250,000	$55,648	$74,197	$85,572	$96,946	$108,320
$275,000	$55,648	$74,197	$85,572	$96,946	$108,320
$300,000	$55,648	$74,197	$85,572	$96,946	$108,320
$325,000	$55,648	$74,197	$85,572	$96,946	$108,320
$350,000	$55,648	$74,197	$85,572	$96,946	$108,320
$375,000	$55,648	$74,197	$85,572	$96,946	$108,320
$400,000	$55,648	$74,197	$85,572	$96,946	$108,320
$425,000	$55,648	$74,197	$85,572	$96,946	$108,320
$450,000	$55,648	$74,197	$85,572	$96,946	$108,320

The final average pay formula portion of the defined benefit plan calculates retirement benefits based upon the highest consecutive sixty month average cash compensation and annual incentive bonuses, if any, out of the final one hundred twenty months of employment with no reduction for social security. Retirement benefits are paid for the life of the participant. Mr. Haines, Mr. Moore and Mr. Ruelle had 16.3 years, 22.4 years and 10.5 years of credited service respectively when their previous employment terminated. As of January 1, 2004, Mr. Sterbenz, Mr. Dixon and Mr. Irick had 6.6 years, 28.3 years and 4.6 years of credited service respectively.

The cash balance formula portion of the defined benefit plan calculates retirement benefits based upon the lifetime employment of the participant. Participants earn monthly contribution credits based upon their age. In addition, monthly interest credits are added to participants' account balance based upon the one-year Treasury constant maturities rate with a minimum 5% annual interest credit and a maximum 10% annual interest credit. The estimated lump sum benefit payable to Mr. Haines, Mr. Moore and Mr. Ruelle at the normal retirement age of 65 under the cash balance formula portion of the defined benefit plan based on a 5% interest credit is as follows: Mr. Haines, $153,085; Mr. Moore, $311,824; and Mr. Ruelle, $573,670.

Three of our named executive officers, Mr. Haines, Mr. Moore and Mr. Ruelle, participated in and accrued vested benefits under an executive salary continuation plan in connection with their prior employment with us. The plan has since been discontinued and they are not accruing additional benefits as a result of their current employment. One other executive officer, who became a participant in the plan prior to its discontinuation, currently participates in and is accruing benefits under the plan. None of the other executive officers, including the other named executive officers, are participants in the plan.

Mr. Haines and Mr. Moore receive an annual benefit of $68,795 and $163,769, respectively, under the plan. The estimated annual benefit payable to Mr. Ruelle under the plan at normal retirement age at or after age 65 is $15,896. A reduced benefit would be payable to Mr. Ruelle if he commenced payment of the benefit prior to age 60.

EMPLOYMENT CONTRACTS

We have entered into employment agreements with each of the named executive officers except Mr. Dixon, who retired from his position with us on December 31, 2003. The agreements have a four year term, except the agreement with Mr. Irick has a three year term. The agreements provide for base annual salaries (Mr. Haines, $750,000; Mr. Moore, $400,000; Mr. Sterbenz, $275,000; Mr. Ruelle, $275,000; and Mr. Irick, $175,000) and grants of restricted share units (Mr. Haines, 250,000; Mr. Moore, 137,500; Mr. Sterbenz, 125,000;

Mr. Ruelle, 125,000; and Mr. Irick, 54,000). The restricted share units vest ratably in equal installments on an annual basis over the term of the contracts, subject to the officer continuing to be employed by us on each anniversary date. The agreements provide that the officers will not receive any additional cash or stock compensation during the term of the agreements other than stock-based compensation arising from discounts received on shares purchased pursuant to our Employee Stock Purchase Plan. The officers are entitled to various periods of vacation and participate in all other employee benefit plans and programs provided to all of our non-union employees. We reimburse the officers for all reasonable expenses incurred in the conduct of our business, provided they account for these expenses in accordance with our applicable policies.

Pursuant to their employment agreements, Mr. Haines and Mr. Ruelle received certain benefits in connection with their relocation to Kansas. We reimbursed Mr. Haines and Mr. Ruelle for the cost of temporary housing in Topeka, Kansas for periods of eight months and six months, respectively, and for the costs of travel for each officer and his immediate family to and from their previous places of residence and Topeka, Kansas. We agreed to purchase two residences located in El Paso at Mr. Haines' request at any time prior to the end of the term (which request has been made for one residence) for a price equal to his purchase price plus the cost of all improvements and the costs incurred in connection with their sale, provided that the aggregate price paid by us for both residences will not exceed $500,000. We also agreed to reimburse Mr. Haines and Mr. Ruelle for moving expenses related to their relocation to Kansas.

We paid Mr. Haines a $50,000 signing bonus and made charitable contributions totaling $200,000 to charitable organizations designated by him. Mr. Haines matched the charitable contributions from his personal funds. Mr. Haines may devote two weeks each year to teaching at the University of Texas at El Paso.

The employment agreements contain customary provisions regarding indemnification, non-solicitation, non-disparagement and the protection of confidential information. Except to pay taxes, the officers will not sell any shares of our common stock during the term of the agreement without the prior approval of our Board of Directors in the case of Mr. Haines and without the prior approval of Mr. Haines in the case of all other officers. Prior approval will not be unreasonably withheld.

If the employment of any named executive officer other than Mr. Irick terminates in a "Qualifying Termination," he will be entitled to receive a lump-sum cash amount equal to the sum of his base salary through the date of termination, his base salary for the remainder of the term of the agreement, and any accrued vacation pay, to the extent not previously paid. Restricted share units awarded to the officers will fully vest upon a Qualifying Termination. Also, we will continue to provide medical benefits to Mr. Haines and his dependents for life.

The term "Qualifying Termination" means termination by us other than for "Cause," by the officer for "Good Reason" or by the officer during the 90 day period after a "Change in Control" (as each term is defined in the employment agreement). The term "Cause" means the officer's conviction of a felony or a crime involving moral turpitude, his commission of a willful act of fraud or dishonesty with respect to us, his willful and repeated failure to perform substantially his material duties to us, his engaging in significant activity that is materially harmful to our reputation, or his breach of his fiduciary responsibilities to us or our shareholders.

If the employment of any named executive officer other than Mr. Irick terminates under circumstances not qualifying as a "Qualifying Termination," we will make a lump-sum cash payment equal to the sum of his base salary through the date of termination and any accrued vacation pay, and, in the case of Mr. Haines, we will continue to provide medical benefits to him and his dependents for life.

We have entered into change in control agreements with Mr. Irick and other of our officers and key employees, but not any of the other named executive officers. The agreements have three year terms with an automatic extension of one year on each anniversary, unless prior notice is given by the officer or by us. The agreements are intended to insure the officers' continued service and dedication to us and to ensure their objectivity in considering on our behalf any transaction which would result in a change in control of us.

Under the change in control agreements, an officer is entitled to benefits if his or her employment is terminated within two years of a change in control by us other than for "Cause" or by the officer for "Good Reason" (as each term is defined in the change in control agreements). Upon such termination, we or our successor, must make a lump-sum cash payment to the officer, in addition to any other compensation to which the officer is entitled, of two times such officer's adjusted salary, plus two times such officer's bonus amount, plus the actuarial equivalent of the excess of the officer's accrued pension benefits, computed as if the officer had two additional years of benefit accrual service, over the officer's vested accrued pension benefits utilizing the officer's current salary without regard for any salary limits imposed for qualified pension plans. In addition, restricted share units, dividend equivalents and other stock based incentives or compensation accelerate and vest and restrictions or performance criteria lapse.

COMPENSATION COMMITTEE REPORT

Background

The full Board of Directors (the "Board"), rather than the Compensation Committee of the Board (the "Committee"), reviewed and approved the current compensation of the Company's executive officers. In 2003, the Committee held no meetings until August 2003 because of significant changes in the membership of the Board and the Committee. In late 2002, both David C. Wittig, the Company's former chairman, president and chief executive officer, and Douglas T. Lake, the Company's former executive vice president and chief strategic officer who was also a director, resigned from the Board. In addition, three outside directors retired in the period from November 2002 to May 2003, and four new directors were appointed to the Board in 2003.

In August 2003, the Committee resumed the administration of the Company's executive compensation programs. The current members of the Committee are Ms. Carter (Chairman), Mr. Chandler and Mr. Isaac. All members are independent directors as defined in the Company's Corporate Governance Guidelines. Ms. Carter and Mr. Chandler were appointed to the Committee on July 16, 2003 and Mr. Isaac was appointed to the Committee on December 10, 2003. In late 2003, the Committee adopted and the Board approved a new Committee charter. The Company posts the Committee charter and the Corporate Governance Guidelines on its web site and provides copies upon request to any shareholder.

In April 2003, the Board substantially modified officer compensation so that all officers receive compensation structured in the same manner as the compensation provided to James S. Haines, Jr., the Company's chief executive officer and president. Each officer receives a base salary, an award of restricted share units (including associated dividend equivalents) under the Company's 1996 Long Term Incentive and Share Award Plan (the "LTIP Plan"), and other employee benefits available to all of the Company's non-union employees. This compensation is set forth in employment agreements with terms of two to four years and other customary provisions regarding termination, indemnification, non-solicitation, non-disparagement and the protection of confidential information. Previously, the Company utilized base salary, short term incentive and long term incentive programs for officer compensation. The Company continued to use the prior programs in 2003 to determine compensation for management employees other than officers. The objective of the current compensation program is to provide compensation that enables the Company to attract, motivate and retain talented and dedicated executives, foster a team orientation toward the achievement of business objectives, and directly link the success of the Company's executives with that of its shareholders.

In structuring the Company's compensation plans, the Board takes into consideration Section 162(m) of the Internal Revenue Code (which disallows the deduction of compensation in excess of $1,000,000 except for certain payments based upon performance goals) and other factors the Board deems appropriate. As a result, some of the compensation under the Company's compensation plans may not be deductible under Section 162(m).

Compensation Review and Philosophy

The compensation of three of the Company's named executive officers was established when they accepted employment with the Company. Mr. Haines and William B. Moore, the Company's executive vice president and chief operating officer, joined the Company in December 2002, and Mark A. Ruelle, the Company's executive vice president and chief financial officer, joined the Company in January 2003.

In April 2003, the Board comprehensively reviewed the Company's compensation for other executive officers. The Board considered a study prepared by an independent human resources consulting firm and management analysis of market data from other external sources of compensation for executive officers of comparably sized regulated utilities and energy companies. Based upon this review, the Board approved adjustments to the compensation of the other executive officers, including Douglas R. Sterbenz, Senior Vice President, Generation and Marketing, and Larry D. Irick, Vice President, General Counsel and Corporate Secretary. No adjustment was made to the compensation of Richard A. Dixon, Senior Vice President, Operations Strategy, because of his intention to retire at the end of 2003.

The Company's compensation philosophy in 2003 was to target each executive officer's total cash compensation and total direct compensation to approximate the median level of compensation in the national market for similar positions at comparably sized utilities.

Total Cash Compensation

The total cash compensation of executive officers, including the named executive officers, consists of base salary and dividend equivalents on restricted share units. Total cash compensation for each executive officer is structured to be comparable to total cash compensation for persons holding similar positions in the national market at comparably sized utilities. The employment agreements with the executive officers do not provide for increases in base salary during the term of the agreement.

Long Term Incentives

Pursuant to the LTIP Plan, the Company awards long term incentive compensation in the form of restricted share units to executive officers, including the named executive officers, and other key employees who are in positions which can affect the Company's long term success through the formation and execution of its business strategies. Dividend equivalents are paid on restricted share units from the date of grant. The value of a single dividend equivalent is equal to the dividends that would have been paid or payable on a share from the date of grant. The Company believes restricted share units: (1) focus officers' efforts on performance which will increase the value of the Company's common stock; (2) align the interests of management with those of the Company's shareholders; (3) provide a competitive long term incentive opportunity; and (4) provide a retention incentive for key employees.

Each of the executive officers of the Company, including the named executive officers other than Mr. Dixon, received an award of restricted share units upon joining the Company or when compensation was adjusted in 2003. The employment agreements with the executive officers do not provide for additional restricted share unit awards during the term of the agreement. The restricted share units vest annually in various increments on each anniversary of the grant date, subject to the officer continuing to be employed by the Company on each anniversary date. The number of restricted share units awarded and the vesting period vary by position. They were set at levels and periods to provide officers annual total direct compensation, consisting of total cash compensation and the value of the portion of the restricted share unit award that vests annually, that approximates the median level of total direct compensation in the national market for similar positions at comparably sized utilities. Awards of restricted share units were valued based upon the closing price of the Company's common stock near the date of grant. The awards are designed to provide total direct compensation that exceeds the market median if there is significant appreciation in the price of the Company's common stock following the date of grant. Restricted share units and dividend equivalents also vest if an officer's employment is terminated by the Company other than for cause, or by the officer for good reason or within 90 days following a change in control of the Company.

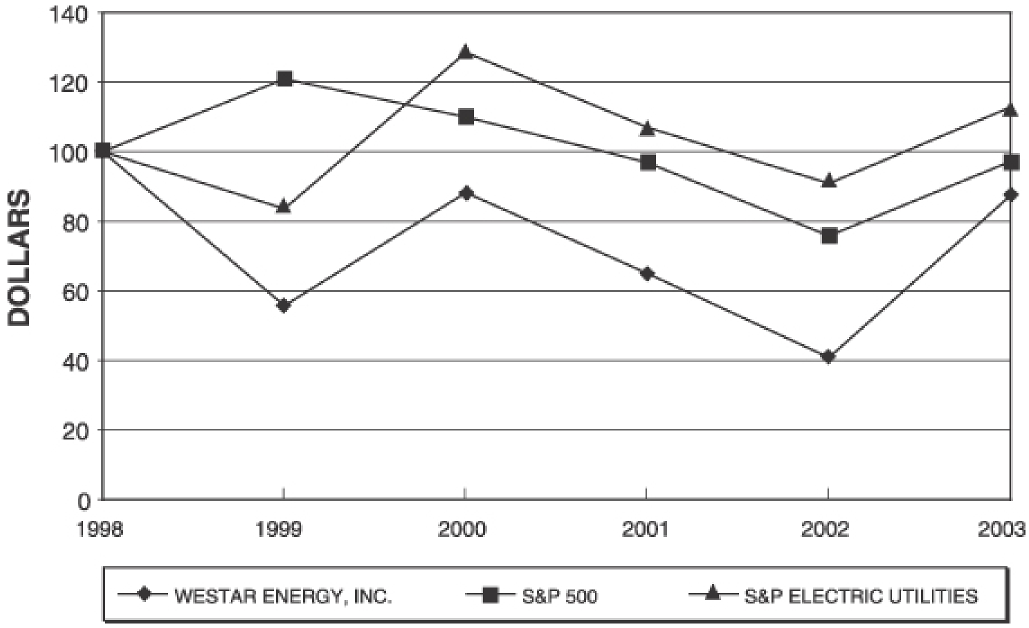
Chief Executive Officer-James S. Haines, Jr.

Mr. Haines has served as chief executive officer and president of the Company since December 6, 2002. He receives an annual base salary of $750,000, which is fixed for the four-year term of his employment agreement. He also received a grant of 250,000 restricted share units when his employment commenced. The restricted share units vest in one-fourth increments on each anniversary of his start date subject to his continuing to be employed by the Company on each anniversary date. One-fourth of the restricted share units vested on December 6, 2003. The restricted share units were intended to provide Mr. Haines a significant long term incentive opportunity in the event of appreciation in the Company's common stock price. Mr. Haines does not receive any additional cash or stock compensation during the term of his employment agreement, except for stock based compensation arising from discounts received or shares purchased pursuant to the Company's Employee Stock Purchase Plan. See "Employment Contracts" for a description of other terms of Mr. Haines' employment agreement with the Company.

Westar Energy, Inc. Board of Directors

PERFORMANCE GRAPH

The following performance graph compared the performance of our common stock during the period beginning on December 31, 1998 and ending on December 31, 2003 to the Standard & Poor's 500 Index and the Standard & Poor's Electric Utility Index. The graph assumes a $100 investment in our common stock and in each of the indexes at the beginning of the period and a reinvestment of dividends paid on such investments throughout the period.



	Cumulative Total Return					
	Dec-98	Dec-99	Dec-00	Dec-01	Dec-02	Dec-03
Westar Energy, Inc.	$ 100	$ 55.75	$ 88.29	$ 64.98	$ 40.80	$ 87.51
S&P 500	$ 100	$ 121.04	$ 110.03	$ 96.94	$ 75.52	$ 97.18
S&P Electric Utilities	$ 100	$ 83.60	$ 128.61	$ 107.03	$ 90.91	$ 112.80

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table sets forth certain information regarding beneficial ownership of the common stock as of February 15, 2004 by each person who is known by us to own beneficially more than 5% of the outstanding shares of common stock.

Name and Address of Beneficial Owner	Percent of Class	Amount and Nature of Beneficial Ownership
Mario J. Gabelli (a) One Corporate Center Rye, NY 10580	6.74%	4,898,896

(a) As reported in a Schedule 13F filed with the Securities and Exchange Commission on February 16, 2004 by GAMCO Investors, Inc.

SECURITY OWNERSHIP OF MANAGEMENT

The following information relating to the ownership of shares of our common stock is furnished with respect to each of our current directors and named executive officers individually, and with respect to our current directors and executive officers as a group. The information provided is as of February 23, 2004.

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Name of Beneficial Owner	Amount and Nature of Beneficial Ownership (1)		Percent of Class
Outside Directors			
Mollie Hale Carter	3,054	(2)	*
Charles Q. Chandler, IV	11,527	(2)	*
R.A. Edwards	21,270	(2)(3)	*
B. Anthony Isaac	2,000	(2)	*
Arthur B. Krause	5,040	(2)	*
Michael F. Morrissey	3,921	(2)	*
John C. Nettels, Jr.	16,151	(2)(4)	*
Management			
Richard A. Dixon (5)	26,790	(2)	*
James S. Haines, Jr.	232,857	(2)	*
Larry D. Irick	70,583	(2)(6)	*
William B. Moore	162,319	(2)	*
Mark A. Ruelle	112,194	(2)	*
Douglas R. Sterbenz	153,725	(2)	*
All directors and executive officers as a group (17 individuals)	968,477	(7)	1.32%

* Represents less than 1%

(1) Includes beneficially owned shares held in employee savings plans and the Employee Stock Purchase Plan, and shares deferred under the Long-Term Incentive and Share Award Plan, the Stock for Compensation Program and the Outside Directors' Deferred Compensation Plan. No director or named executive officer owns any of our equity securities other than our common stock.

(2) Includes restricted share units as follows: Ms. Carter, 1,536; Mr. Chandler, 2,558; Mr. Edwards, 2,656; Mr. Isaac, 1,012; Mr. Krause, 1,536; Mr. Morrissey, 1,985; Mr. Nettels, 2,558; Mr. Dixon, 8,700; Mr. Haines, 187,500; Mr. Irick, 57,800; Mr. Moore, 117,907; Mr. Ruelle, 93,750; Mr. Sterbenz, 129,660; and 109,440 restricted share units granted to four other executive officers in the group.

(3) Includes 1,963 shares held by Mr. Edwards' spouse, not subject to his voting or investment power.

(4) Includes 500 shares of our common stock held in a trust in which Mr. Nettels has shared investment and voting power.

(5) Mr. Dixon retired as senior vice president on December 31, 2003.

(6) Includes 943 shares held by Mr. Irick's spouse (including 90 restricted share units). These shares are not subject to Mr. Irick's voting or investment power.

(7) Includes shares referred to in items (1) through (6) above.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Indebtedness of Management

During 2001 and 2002, we extended loans to our officers for the purpose of purchasing shares of our common stock. We eliminated this program and no additional loans have been made since the enactment of federal legislation that became effective July 30, 2002. During 2003, two of our named executive officers had balances in excess of $60,000 (Mr. Sterbenz, $200,000 and Mr. Irick, $150,000). The interest rate charged on the loans varied on a quarterly basis. In 2003 the rates were: (a) first quarter, 4.42%; (b) second quarter, 4.37%; (c) third quarter, 4.18%; and (d) fourth quarter, 4.19%. The principal amount of these loans was repaid by each officer in 2003. The balance outstanding at December 31, 2003 was approximately $1,850 which consisted of accrued interest. As of January 31, 2004, these interest amounts were paid. For the year ended December 31, 2003, we recorded approximately $35,178 in interest income on all loans made under the program.

Certain Business Relationships

During 2003, we retained the law firm of Stinson Morrison Hecker LLP, where John C. Nettels, Jr. is a partner, in connection with certain legal matters. We believe these services were provided on terms typical for firms not affiliated with any director.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Independent Auditor Fees

The aggregate fees billed by our principal accounting firm, Deloitte & Touche LLP, the member firms of Deloitte Touche Tohmatsu, and their respective affiliates (collectively, "Deloitte & Touche") for fees billed for fiscal years ended December 31, 2003 and 2002 are as follows:

	2003	2002
Audit fees (a)	$ 1,288,559	$ 3,432,896
Audit related fees (b)	126,444	90,085
Total audit and audit related fees	1,415,003	3,522,981
Tax fees (c)	22,203	399,922
Total fees	$ 1,437,206	$ 3,922,903

(a) The 2002 audit fees include approximately $1.5 million for 2000 and 2001 re-audit fees.

(b) These fees relate to the audits of company sponsored benefit plans, Sarbanes Oxley 404 implementation assistance and other agreed upon procedures for the fiscal year ended December 31, 2003 and to the audits of company sponsored benefit plans for the fiscal year ended December 31, 2002.

(c) These fees are for consulting related to the tax treatments of the sales or divestitures of investments held by us for both the fiscal years ended December 31, 2003 and 2002.

Each of the permitted non-audit services has been pre-approved by the Audit Committee or the Audit Committee's Chairman pursuant to delegated authority by the Audit Committee, other than de minimus non-audit services for which the pre-approval requirements are waived in accordance with the rules and regulations of the SEC.

Audit Committee Pre-Approval Policies and Procedures

The Audit Committee charter provides that the Audit Committee will pre-approve audit services and non-audit services to be provided by our independent auditors before the accountant is engaged to render these services. The Audit Committee may consult with management in the decision-making process, but may not delegate this authority to management. The Audit Committee may delegate its authority to pre-approve services to one or more committee members, provided that the designees present the pre-approvals to the full committee at the next committee meeting.

The Audit Committee has authorized the Chairman of the Audit Committee to pre-approve the retention of an independent auditor for audit-related and permitted non-audit services not contemplated by the engagement letter for the annual audit, provided that: (a) these services are approved no more than thirty days in advance of the auditor commencing work; (b) the fees to be paid to the auditor for services related to any single engagement do not exceed $25,000; (c) the aggregate fees to be paid to the auditor for services in any calendar year do not exceed $100,000; and (d) the Chairman advises the Audit Committee of the pre-approval of the services at the next meeting of the Audit Committee following the approval.

PART IV

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

FINANCIAL STATEMENTS INCLUDED HEREIN

Westar Energy, Inc.

ONEOK, Inc. and Subsidiaries

SCHEDULES

Schedule II - Valuation and Qualifying Accounts

Schedules omitted as not applicable or not required under the Rules of Regulation S-X: I, III, IV, and V

REPORTS ON FORM 8-K FILED DURING THE QUARTER ENDED DECEMBER 31, 2003:

Form 8-K filed November 20, 2003 -	Announcement that we will sell all of our remaining ONEOK, Inc. stock through Cantor Fitzgerald & Co. at a price of $19.15 per share resulting in $262.0 million in gross proceeds.
Form 8-K filed December 23, 2003 -	Announcement that we have entered into a definitive agreement to sell our approximate 88% equity interest in Protection One and to transfer our rights and obligations as the lender under Protection One's credit facility to POI Acquisition, L.L.C.

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EXHIBIT INDEX

All exhibits marked "I" are incorporated herein by reference. All exhibits marked by an asterisk are management contracts or compensatory plans or arrangements required to be identified by Item 14(a)(3) of Form 10-K. Exhibits previously filed are marked "†".

	Description	
3(a)	-By-laws of the company, as amended March 16, 2000 (filed as Exhibit 3(a) to December 31, 1999 Form 10-K)	I
3(b)	-Restated Articles of Incorporation of the company, as amended through May 25, 1988 (filed as Exhibit 4 to Registration Statement, SEC File No. 33-23022)	I
3(c)	-Certificate of Amendment to Restated Articles of Incorporation of the company dated March 29, 1991	I
3(d)	-Certificate of Designations for Preference Stock, 8.5% Series, without par value, dated March 31, 1991 (filed as Exhibit 3(d) to December 1993 Form 10-K)	I
3(e)	-Certificate of Correction to Restated Articles of Incorporation of the company dated December 20, 1991 (filed as Exhibit 3(b) to December 1991 Form 10-K)	I
3(f)	-Certificate of Designations for Preference Stock, 7.58% Series, without par value, dated April 8, 1992, (filed as Exhibit 3(e) to December 1993 Form 10-K)	I
3(g)	-Certificate of Amendment to Restated Articles of Incorporation of the company dated May 8, 1992 (filed as Exhibit 3(c) to December 31, 1994 Form 10-K)	I
3(h)	-Certificate of Amendment to Restated Articles of Incorporation of the company dated May 26, 1994 (filed as Exhibit 3 to June 1994 Form 10-Q)	I
3(i)	-Certificate of Amendment to Restated Articles of Incorporation of the company dated May 14, 1996 (filed as Exhibit 3(a) to June 1996 Form 10-Q)	I
3(j)	-Certificate of Amendment to Restated Articles of Incorporation of the company dated May 12, 1998 (filed as Exhibit 3 to March 1998 Form 10-Q)	I
3(k)	-Form of Certificate of Designations for 7.5% Convertible Preference Stock (filed as Exhibit 99.4 to November 17, 2000 Form 8-K)	I
3(l)	-Certificate of Amendment to Restated Articles of Incorporation of the company dated July 21, 1999 (filed as Exhibit 3(l) to the December 31, 2002 Form 10-K)	I
3(m)	-Certificate of Amendment to Restated Articles of Incorporation of the company dated June 19, 2002 (filed as Exhibit 3(m) to the December 31, 2002 Form 10-K)	I
4(a)	-Deferrable Interest Subordinated Debentures dated November 29, 1995, between the company and Wilmington Trust Delaware, Trustee (filed as Exhibit 4(c) to Registration Statement No. 33-63505)	I
4(b)	-Mortgage and Deed of Trust dated July 1, 1939 between the company and Harris Trust and Savings Bank, Trustee (filed as Exhibit 4(a) to Registration Statement No. 33-21739)	I
4(c)	-First and Second Supplemental Indentures dated July 1, 1939 and April 1, 1949, respectively (filed as Exhibit 4(b) to Registration Statement No. 33-21739)	I
4(d)	-Sixth Supplemental Indenture dated October 4, 1951 (filed as Exhibit 4(b) to Registration Statement No. 33-21739)	I
4(e)	-Fourteenth Supplemental Indenture dated May 1, 1976 (filed as Exhibit 4(b) to Registration Statement No. 33-21739)	I
4(f)	-Twenty-Eighth Supplemental Indenture dated July 1, 1992 (filed as Exhibit 4(o) to the December 1992 Form 10-K)	I
4(g)	-Twenty-Ninth Supplemental Indenture dated August 20, 1992 (filed as Exhibit 4(p) to the December 1992 Form 10-K)	I
4(h)	-Thirtieth Supplemental Indenture dated February 1, 1993 (filed as Exhibit 4(q) to the December 1992 Form 10-K)	I
4(i)	-Thirty-First Supplemental Indenture dated April 15, 1993 (filed as Exhibit 4(r) to Registration Statement No. 33-50069)	I
4(j)	-Thirty-Second Supplemental Indenture dated April 15, 1994 (filed as Exhibit 4(s) to the December 31, 1994 Form 10-K)	I
4(k)	-Thirty-Fourth Supplemental Indenture dated June 28, 2000 (filed as Exhibit 4(v) to the December 31, 2000 Form 10-K)	I
4(l)	-Thirty-Fifth Supplemental Indenture dated May 10, 2002 between the company and BNY Midwest Trust Company, as Trustee (filed as Exhibit 4.1 to the March 31, 2002 Form 10-Q)	I

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4(m)	-Forty-First Supplemental Indenture dated June 6, 2002 between Kansas Gas and Electric Company and BNY Midwest Trust Company, as Trustee (filed as Exhibit 4.1 to the June 30, 2002 Form 10-Q)	I
4(n)	-Debt Securities Indenture dated August 1, 1998 (filed as Exhibit 4.1 to the June 30, 1998 Form 10-Q)	I
4(o)	-Securities Resolution No. 2 dated as of May 10, 2002 under Indenture dated as of August 1, 1998 between Western Resources, Inc. and Deutsche Bank Trust Company Americas (filed as Exhibit 4.2 to the March 31, 2002 Form 10-Q)	I
	Instruments defining the rights of holders of other long-term debt not required to be filed as Exhibits will be furnished to the Commission upon request.	
10(a)	-Long-Term Incentive and Share Award Plan (filed as Exhibit 10(a) to the June 1996 Form 10-Q)*	I
10(b)	-Form of Employment Agreements with Messers. Lake and Wittig (filed as Exhibit 10(b) to the December 31, 2000 Form 10-K)*	I
10(c)	-A Rail Transportation Agreement among Burlington Northern Railroad Company, the Union Pacific Railroad Company and the Company (filed as Exhibit 10 to the June 1994 Form 10-Q)	I
10(d)	-Agreement between the company and AMAX Coal West Inc. effective March 31, 1993 (filed as Exhibit 10(a) to the December 31, 1993 Form 10-K)	I
10(e)	-Agreement between the company and Williams Natural Gas Company dated October 1, 1993 (filed as Exhibit 10(b) to the December 31, 1993 Form 10-K)	I
10(f)	-Deferred Compensation Plan (filed as Exhibit 10(i) to the December 31, 1993 Form 10-K)*	I
10(g)	-Short-term Incentive Plan (filed as Exhibit 10(k) to the December 31, 1993 Form 10-K)*	I
10(h)	-Outside Directors’ Deferred Compensation Plan (filed as Exhibit 10(l) to the December 31, 1993 Form 10-K)*	I
10(i)	-Executive Salary Continuation Plan of Western Resources, Inc., as revised, effective September 22, 1995 (filed as Exhibit 10(j) to the December 31, 1995 Form 10-K)*	I
10(j)	-Letter Agreement between the company and David C. Wittig, dated April 27, 1995 (filed as Exhibit 10(m) to the December 31, 1995 Form 10-K)*	I
10(k)	-Form of Shareholder Agreement between New ONEOK and the company (filed as Exhibit 99.3 to the December 12, 1997 Form 8-K)	I
10(l)	-Form of Split Dollar Insurance Agreement (filed as Exhibit 10.3 to the June 30, 1998 Form 10-Q)*	I
10(m)	-Amendment to Letter Agreement between the company and David C. Wittig, dated April 27, 1995 (filed as Exhibit 10 to the June 30, 1998 Form 10-Q/A)*	I
10(n)	-Letter Agreement between the company and Douglas T. Lake, dated August 17, 1998 (filed as Exhibit 10(n) to the December 31, 1999 Form 10-K)*	I
10(o)	-Form of Change of Control Agreement with officers of the company (filed as Exhibit 10(o) to the December 31, 2000 Form 10-K)*	I
10(p)	-Amendment to Outside Directors’ Deferred Compensation Plan dated May 17, 2001 (filed as Exhibit 10(p) to the December 31, 2000 Form 10-K)*	I
10(q)	-Form of loan agreement with officers of the company (filed as Exhibit 10(r) to the December 31, 2001 Form 10-K)*	I
10(r)	-Amendment to Employment Agreement dated April 1, 2002 between the company and David C. Wittig (filed as Exhibit 10.1 to the June 30, 2002 Form 10-Q)*	I
10(s)	-Amendment to Employment Agreement dated April 1, 2002 between the company and Douglas T. Lake (filed as Exhibit 10.2 to the June 30, 2002 Form 10-Q)*	I
10(t)	-Credit Agreement dated as of June 6, 2002 among the company, the lenders from time to time party there to, JPMorgan Chase Bank, as Administrative Agent, Citibank, N.A., as Syndication Agent, and Bank of America, N.A., as Documentation Agent (filed as Exhibit 10.3 to the June 30, 2002 Form 10-Q)	I
10(u)	-Employment Agreement dated September 23, 2002 between the company and David C. Wittig (filed as Exhibit 10.1 to the September 30, 2002 Form 10-Q)*	I
10(v)	-Employment Agreement dated September 23, 2002 between the company and Douglas T. Lake (filed as Exhibit 10.1 to the November 25, 2002 Form 8-K)*	I
10(w)	-Transaction Agreement between ONEOK and the company dated as of January 9, 2003 (filed as Exhibit 10.1 to the January 10, 2003 Form 8-K)	I
10(x)	-Shareholder Agreement between ONEOK and the company dated as of January 9, 2003 (filed as Exhibit 10.2 to the January 10, 2003 Form 8-K)	I
10(y)	-Registration Rights Agreement between ONEOK and the company dated as of January 9, 2003 (filed as Exhibit 10.3 to the January 10, 2003 Form 8-K)	I

10(z)	-Employment Agreement dated April 10, 2003 between the company and James S. Haines, Jr. (filed as Exhibit 10(z) to the December 31, 2002 Form 10-K)*	I
10(aa)	-Letter Agreement dated November 1, 2003 between Westar Energy, Inc. and James S. Haines, Jr. (filed as Exhibit 10(a) to the September 30, 2003 Form 10-Q)*	I
10(ab)	-Letter Agreement dated November 1, 2003 between Westar Energy, Inc. and William B. Moore (filed as Exhibit 10(b) to the September 30, 2003 Form 10-Q)*	I
10(ac)	-Letter Agreement dated November 1, 2003 between Westar Energy, Inc. and Mark A. Ruelle (filed as Exhibit 10(c) to the September 30, 2003 Form 10-Q)*	I
10(ad)	-Letter Agreement dated November 1, 2003 between Westar Energy, Inc. and Douglas R. Sterbenz (filed as Exhibit 10(d) to the September 30, 2003 Form 10-Q)*	I
10(ae)	-Letter Agreement dated November 1, 2003 between Westar Energy, Inc. and Larry D. Irick (filed as Exhibit 10(e) to the September 30, 2003 Form 10-Q)*	I
10(af)	-Waiver and Amendment, dated as of November 6, 2003, to the Credit Agreement, dated as of June 6, 2002, among Westar Energy, Inc., the Lenders from time to time party thereto, JPMorgan Chase Bank, as Administrative Agent for the Lenders, Citibank, N.A., as Syndication Agent, and Bank of America, N.A., as Documentation Agent (filed as Exhibit 10(f) to the September 30, 2003 Form 10-Q)	I
12	-Computations of Ratio of Consolidated Earnings to Fixed Charges	
16	-Letter from Arthur Andersen LLP to the SEC dated May 30, 2002 (filed as Exhibit 16 to the May 30, 2002 Form 8-K)	I
21	-Subsidiaries of the Registrant†	
23(a)	-Independent Auditors' Consent, Deloitte & Touche LLP	
23(b)	-Independent Auditors' Consent, KPMG LLP	
31(a)	-Certification of Principal Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 certifying the quarterly report provided for the period ended December 31, 2003	
31(b)	-Certification of Principal Accounting Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 certifying the quarterly report provided for the period ended December 31, 2003	
32(a)	-Certifications pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 certifying the annual report provided for the year ended December 31, 2003 (furnished and not to be considered filed as part of the Form 10-K)	
99(a)	-Kansas Corporation Commission Order dated November 8, 2002 (filed as Exhibit 99.2 to the September 30, 2002 Form 10-Q)	I
99(b)	-Kansas Corporation Commission Order dated December 23, 2002 (filed as Exhibit 99.1 to the December 27, 2002 Form 8-K)	I
99(c)	-Form of Certificate of the Designations of $0.925 Series D Non-Cumulative Convertible Preferred Stock of ONEOK (filed as Exhibit 99.1 to the January 10, 2003 Form 8-K)	I
99(d)	-Debt Reduction and Restructuring Plan filed with the Kansas Corporation Commission on February 6, 2003 (filed as Exhibit 99.1 to the February 6, 2003 Form 8-K)	I
99(e)	-Kansas Corporation Commission Order dated February 10, 2003 (filed as Exhibit 99.1 to the February 11, 2003 Form 8-K)	I
99(f)	-Kansas Corporation Commission Order dated March 11, 2003 (filed as Exhibit 99(f) to the December 31, 2002 Form 10-K)	I
99(g)	-Demand for Arbitration (filed as Exhibit 99.1 to the June 13, 2003 Form 8-K)	I
99(h)	-Stipulation and Agreement filed with the Kansas Corporation Commission on July 21, 2003 (filed as Exhibit 99.1 to the July 22, 2003 Form 8-K)	I
99(i)	-Transaction Agreement, dated August 4, 2003, between ONEOK, Inc., Westar Energy, Inc., and Westar Industries, Inc. (filed as Exhibit 99.1 to the August 6, 2003 Form 8-K)	I
99(j)	-Underwriting Agreement, dated August 5, 2003, between J.P. Morgan Securities Inc., ONEOK, Inc., Westar Energy, Inc., and Westar Industries, Inc. (filed as Exhibit 99.2 to the August 6, 2003 Form 8-K)	I
99(k)	-Purchase Agreement, dated as of December 23, 2003, between POI Acquisition, L.L.C., Westar Industries, Inc. and Westar Energy, Inc. (filed as Exhibit 99.2 to the December 23, 2003 Form 8-K)	I

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WESTAR ENERGY, INC.
SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS

Description	Balance at Beginning of Period	Charged to Costs and Expenses	Deductions	Balance at End of Period
		(In Thousands)		
Year ended December 31, 2001				
Allowances deducted from assets for doubtful accounts (a)	244	109	(80)	273
Accrued exit fees, shut-down and severance costs (b)	380	—	(337)	43
Year ended December 31, 2002				
Allowances deducted from assets for doubtful accounts (a)	273	138	(411)	—
Accrued exit fees, shut-down and severance costs (b)	43	—	(43)	—
Year ended December 31, 2003				
Allowances deducted from assets for doubtful accounts	—	—	—	—
Accrued exit fees, shut-down and severance costs	—	—	—	—

(a) Deductions are primarily the result of write-offs of accounts receivable.
(b) Deductions are the result of payment of accrued severance costs.

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SIGNATURE

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

WESTAR ENERGY, INC.

Date:	March 25, 2004	By:	/s/ Mark A. Ruelle
			Mark A. Ruelle, Executive Vice President and Chief Financial Officer

SIGNATURES

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

Signature	Title	Date
/s/ JAMES S. HAINES, JR. (James S. Haines, Jr.)	Director, Chief Executive Officer and President (Principal Executive Officer)	March 25, 2004
/s/ MARK A. RUELLE (Mark A. Ruelle)	Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	March 25, 2004
/s/ CHARLES Q. CHANDLER IV (Charles Q. Chandler IV)	Chairman of the Board	March 25, 2004
/s/ MOLLIE HALE CARTER (Mollie Hale Carter)	Director	March 25, 2004
/s/ R. A. EDWARDS III (R. A. Edwards III)	Director	March 25, 2004
/s/ B. ANTHONY ISAAC (B. Anthony Isaac)	Director	March 25, 2004
/s/ ARTHUR B. KRAUSE (Arthur B. Krause)	Director	March 25, 2004
/s/ MICHAEL F. MORRISSEY (Michael F. Morrissey)	Director	March 25, 2004
/s/ JOHN C. NETTELS, JR. (John C. Nettels, Jr.)	Director	March 25, 2004

Exhibit 12

WESTAR ENERGY, INC.
Computations of Ratio of Earnings to Fixed Charges and
Computations of Ratio of Earnings to Combined Fixed Charges
and Preferred Dividend Requirements
(Dollars in Thousands)

	Year Ended December 31,				
	2003	2002	2001	2000	1999
Earnings from continuing operations (a)	$ 162,812	$ 78,528	$ 48,224	$ 166,612	$ 67,034
Fixed Charges:					
Interest expense	225,901	237,418	224,777	235,341	209,532
Interest on corporate-owned life insurance borrowings	52,839	52,768	50,409	45,634	36,908
Interest applicable to rentals	23,084	24,647	30,377	29,377	30,853
Total Fixed Charges	301,824	314,833	305,563	310,352	277,293
Distributed income of equity investees	—	2,916	2,769	2,686	3,728
Preferred Dividend Requirements:					
Preferred dividends (b)	968	399	895	1,129	1,129
Income tax required	639	264	591	746	746
Total Preferred Dividend Requirements	1,607	663	1,486	1,875	1,875
Total Fixed Charges and Preferred Dividend Requirements	303,431	315,496	307,049	312,227	279,168
Earnings (c)	$ 464,636	$ 396,277	$ 356,556	$ 479,650	$ 348,055
Ratio of Earnings to Fixed Charges	1.54	1.26	1.17	1.55	1.26
Ratio of Earnings to Combined Fixed Charges and Preferred Dividend Requirements	1.53	1.26	1.16	1.54	1.25

(a) Earnings from continuing operations consist of income from continuing operations before income taxes, cumulative effects of accounting changes and preferred dividends adjusted for undistributed earnings from equity investees.

(b) Preferred dividend requirements consist of an amount equal to the pre-tax earnings that would be required to meet dividend requirements on preferred stock.

(c) Earnings are deemed to consist of earnings from continuing operations, fixed charges and distributed income of equity investees. Fixed charges consist of all interest on indebtedness, amortization of debt discount and expense, and the portion of rental expense that represents an interest factor.

EXHIBIT 23A

INDEPENDENT AUDITORS' CONSENT

We consent to the incorporation by reference in Registration Statement Nos. 333-44256, 333-35872, 333-59673, 33-49467, 33-49553, 333-02023, 33-50069, 333-26115, 33-62375 and 333-113415 of Westar Energy, Inc. on Form S-3; Nos. 333-02711, 333-56369, and 333-91720 of Westar Energy, Inc. on Form S-4; Nos. 333-93355, 333-70891, 33-57435, 333-13229, 333-06887, 333-20393, 333-20413 and 333-75395 of Westar Energy, Inc. on Form S-8; and No. 33-50075 of Kansas Gas and Electric Company on Form S-3 of our report dated March 5, 2004 (March 25, 2004 as to Note 32) (which report expresses an unqualified opinion and includes explanatory paragraphs relating to the changes in accounting principles as discussed in Notes 2, 5 and 18, and the restatement of the consolidated statements of cash flows discussed in Note 32) appearing in this annual report on Form 10-K/A of Westar Energy, Inc. for the year ended December 31, 2003.

/s/ DELOITTE & TOUCHE LLP
Kansas City, Missouri
March 25, 2004

EXHIBIT 23B

INDEPENDENT AUDITOR’S CONSENT

To the Board of Directors
ONEOK, Inc.:

We consent to the use of our report dated February 13, 2004, with respect to the consolidated balance sheets of ONEOK, Inc. and subsidiaries as of December 31, 2003 and 2002, and the related consolidated statements of income, shareholders’ equity and comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2003, which report appears in the December 31, 2003 Annual Report on Form 10-K/A of Westar Energy, Inc. Our report refers to a change in accounting for asset retirement obligations, stock-based compensation, and contracts involved in energy trading and risk management activities in 2003, for goodwill and other intangible assets in 2002, and for derivative instruments and hedging activities in 2001.

/s/ KPMG LLP

Tulsa, Oklahoma
March 25, 2004

Exhibit 31(a)

WESTAR ENERGY, INC.
CHIEF EXECUTIVE OFFICER
CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, James S. Haines, Jr., as chief executive officer and president of Westar Energy, Inc., certify that:

1. I have reviewed this annual report on Form 10-K for the period ended December 31, 2003 of Westar Energy, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:
   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b. [Reserved]
   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):
   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect registrant's ability to record, process, summarize and report financial information; and
   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date:	March 25, 2004	By:	/s/ James S. Haines, Jr.
			James S. Haines, Jr., Director, President and Chief Executive Officer, Westar Energy, Inc. (Principal Executive Officer)

Exhibit 31(b)

WESTAR ENERGY, INC.
CHIEF FINANCIAL OFFICER
CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Mark A. Ruelle, as chief financial officer and executive vice president of Westar Energy, Inc., certify that:

1. I have reviewed this annual report on Form 10-K for the period ended December 31, 2003 of Westar Energy, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:
   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b. [Reserved]
   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):
   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect registrant's ability to record, process, summarize and report financial information; and
   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 25, 2004

By: /s/ Mark A. Ruelle

Mark A. Ruelle,
Executive Vice President and Chief Financial Officer
Westar Energy, Inc.
(Principal Accounting Officer)

Exhibit 32(a)

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Westar Energy, Inc. (the Company) on Form 10-K for the year ended December 31, 2003 (the Report), which this certification accompanies, James S. Haines, Jr., in my capacity as Director, President and Chief Executive Officer of the Company, and Mark A. Ruelle, in my capacity as Executive Vice President and Chief Financial Officer of the Company, certify that the Report fully complies with the requirements of Section 13(a) or Section 15(d) of the Securities Exchange Act of 1934 and that information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date:	March 25, 2004	By:	/s/ James S. Haines, Jr.
			James S. Haines, Jr., Director, President and Chief Executive Officer
Date:	March 25, 2004	By:	/s/ Mark A. Ruelle
			Mark A. Ruelle, Executive Vice President and Chief Financial Officer