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

FORM 10-K

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

For the fiscal year ended December 31, 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 1-7324

KANSAS GAS AND ELECTRIC COMPANY
(Exact name of registrant as specified in its charter)

Kansas	**48-1093840**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification Number)**

P.O. BOX 208
Wichita, Kansas 67201
(316) 261-6611

(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: None

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☐ 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 ☒

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

Common Stock, No par value	**1,000 Shares**
(Class)	**(Outstanding at March 12, 2004)**

Registrant meets the conditions of General Instruction I(1)(a) and (b) to Form 10-K for certain wholly owned subsidiaries and is therefore filing an abbreviated form.

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 Westar Energy equity proposed in a Debt Reduction Plan approved by the Kansas Corporation Commission on July 25, 2003,
- compliance with debt and other restrictive covenants,
- interest rates,
- 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 by Westar Energy, Inc. on January 22, 2004 from the Environmental Protection Agency and other environmental matters,
- the impact on Westar Energy, Inc. of 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 Westar Energy, Inc.,
- the impact of changes in interest rates,
- the impact of changing interest rates and other assumptions on our nuclear decommissioning liability for Wolf Creek Generating Station,
- transmission reliability rules,
- Kansas Corporation Commission utility service reliability rules,
- 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

Kansas Gas and Electric Company is a rate-regulated electric utility incorporated in 1990 in the state of Kansas. Unless the context otherwise indicates, all references in this Annual Report on Form 10-K to "the company," "KGE," "we," "us," "our" and similar words are to Kansas Gas and Electric Company. We are a wholly owned subsidiary of Westar Energy, Inc. (Westar Energy) and we provide rate-regulated electric service, together with the electric utility operations of Westar Energy, using the name "Westar Energy." We provide electric generation, transmission and distribution services to approximately 298,000 customers in south-central and southeastern Kansas, including the Wichita metropolitan area. Our corporate headquarters is located in Wichita, Kansas.

We own 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.

SIGNIFICANT BUSINESS DEVELOPMENTS

KCC Orders and The Debt Reduction Plan

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

On July 21, 2003, Westar Energy and 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:

- Westar Energy will fully implement the Debt Reduction Plan by December 31, 2004, unless prevented by events beyond its control, in which case the KCC may extend the deadline for implementation upon a proper showing by Westar Energy.
- Westar Energy will reduce its 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 Westar Energy reduce utility debt to $1.67 billion by August 1, 2003.
- Westar Energy and we will file rate cases with the KCC, 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.
- Westar Energy and we will pay to our Kansas jurisdictional customers combined rebates totaling $10.5 million on May 1, 2005 and $10.0 million on January 1, 2006.
- Westar Energy and we will also pay a rebate to customers for any amounts Westar Energy may recover from David C. Wittig, Westar Energy's former president, chief executive officer and chairman, and Douglas T. Lake, Westar Energy's 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

electric rates during calendar years 1998 through 2002, net of costs Westar Energy incurs to recover the funds. See Note 15 of the Notes to Consolidated Financial Statements, “Legal Proceedings,” for more information about Westar Energy’s efforts to recover compensation from Mr. Wittig and Mr. Lake.

- Westar Industries, Inc. (Westar Industries), a wholly owned subsidiary of Westar Energy, 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 $1.7 million for revenue to be refunded, which is included in other liabilities on our consolidated balance sheets.

ELECTRIC UTILITY OPERATIONS

General

We supply 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 25 Kansas cities. We have contracts for the sale, purchase or exchange of wholesale electricity with other utilities.

Generation Capacity

We have 2,596 megawatts (MW) of generating capacity, including Wolf Creek. 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	1,124	43.3
Nuclear	548	21.1
Natural gas or oil	921	35.5
Diesel fuel	3	0.1
Total	2,596	100.0

Our aggregate 2003 peak system net load of 2,145 MW occurred on August 21, 2003. This is also our all-time peak system net load. We do not anticipate needing additional generating capacity through at least 2006.

We have an agreement with Midwest Energy, Inc. to provide it with peaking capacity of 60 MW through May 2008.

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 62% coal, 31% nuclear and 7% 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, 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 a 20% share, or 443 MW. Westar Energy, the operator of Jeffrey Energy Center, and 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 $0.7 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 $1.19 per MMBtu, or $19.99 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.

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 $0.87 per MMBtu, or $15.07 per ton. The average delivered cost of coal burned at LaCygne 2 was approximately $0.76 per MMBtu, or $13.17 per ton.

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, Jeffrey Energy Center can be served by only one rail carrier. In the event the rail carrier 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 long-term 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 and Neosho Energy Centers. 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 1.6 million MMBtu of natural gas on the spot market for a total cost of $7.4 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 fuels 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.”

We meet a portion of our natural gas transportation requirements through firm natural gas transportation capacity agreements with Southern Star Central Pipeline. The firm transportation agreement that serves Gordon Evans and Murray Gill extends through April 1, 2010. The agreement for the Neosho facility extends through June 1, 2016.

Oil

Our Gordon Evans, Murray Gill and Neosho 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 burned 8.3 million MMBtu of oil for a total cost of $26.5 million. Oil accounted for approximately 6% of our total fuel burned during 2003.

Oil is also used as a start-up fuel at some of our generating stations and in our diesel generator. 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	0.96	0.94	0.95
Natural Gas	4.51	3.44	3.75
Oil	3.20	2.52	3.84
Per MWh Generation	$10.45	$10.23	$11.04

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. We own a 47% interest in Wolf Creek, or 548 MW, which represents 21% 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 35% 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 could 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 facilities, 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.

Westar Energy and 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 sulfur dioxide (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 SO2 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 SO2 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 SO2 and NOx 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 SO2, NOx, particulate matter, mercury and carbon dioxide (CO2) 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 SO2, NOx 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 CO2, NOx, SO2 and mercury, and the President’s “Clear Skies” legislation, which would cap emissions of three pollutants (NOx, SO2 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 Westar Energy under Section 114 regarding projects and maintenance activities that have been conducted since 1980 at the three coal-fired plants it operates. On January 22, 2004, the EPA notified Westar Energy that certain projects completed at Jeffrey Energy Center violated pre-construction permitting requirements of the Clean Air Act.

Westar Energy is in discussions with the EPA concerning this matter but is unable to predict whether the EPA will take further enforcement action. Westar Energy 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 Westar Energy is required to pay any fines or penalties or update or install emissions controls at Jeffrey Energy Center 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 Westar Energy is assessed a penalty as a result of the EPA's allegation, the penalty could be material and may not be recovered in rates. We anticipate that we would be allocated a portion of any of these potential costs.

EMPLOYEES

Westar Energy provides all employees we utilize. As of February 29, 2004, Westar Energy had approximately 2,000 employees. Its current contract with 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 Westar Energy's website at www.wr.com or by responding to requests addressed to its investor relations department at Investor Relations, Westar Energy, Inc., P.O. Box 889, Topeka, Kansas, 66601-0889; phone number (785) 575-1898. 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 Westar Energy's website is not part of this document.

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ITEM 2. PROPERTIES

ELECTRIC UTILITY FACILITIES

Name	Location	Unit No.	Year Installed	Principal Fuel	Unit Capacity (MW)
Gordon Evans Energy Center:	Colwich, Kansas				
Steam Turbines		1	1961	Gas—Oil	147.0
		2	1967	Gas—Oil	383.0
Diesel Generator		1	1969	Diesel	3.0
Jeffrey Energy Center (20%):	St. Marys, Kansas				
Steam Turbines		1(a)	1978	Coal	147.0
		2 (a)	1980	Coal	147.0
		3 (a)	1983	Coal	149.0
Wind Turbines		1 (a)	1999	—	0.1
		2 (a)	1999	—	0.1
LaCygne Station (50%):	LaCygne, Kansas				
Steam Turbines		1 (a)	1973	Coal	344.0
		2 (b)	1977	Coal	337.0
Murray Gill Energy Center:	Wichita, Kansas				
Steam Turbines		1	1952	Gas—Oil	42.0
		2	1954	Gas—Oil	69.0
		3	1956	Gas—Oil	104.0
		4	1959	Gas—Oil	107.0
Neosho Energy Center:	Parsons, Kansas				
Steam Turbine		3	1954	Gas—Oil	69.0
Wolf Creek Generating Station (47%):	Burlington, Kansas				
Nuclear		1 (a)	1985	Uranium	548.0
Total					2,596.2

(a) We jointly own Jeffrey Energy Center (20%), LaCygne 1 generating unit (50%), and Wolf Creek Generating Station (47%). Westar Energy jointly owns 64% of Jeffrey Energy Center.
(b) In 1987, we entered into a sale-leaseback transaction involving our 50% interest in the LaCygne 2 generating unit.

We own approximately 2,200 miles of transmission lines, approximately 10,000 miles of overhead distribution lines and approximately 1,900 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.

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ITEM 3. LEGAL PROCEEDINGS

Information on our legal proceedings is set forth in Notes 3, 13, 15 and 16 of the Notes to Consolidated Financial Statements, “Rate Matters and Regulation,” “Commitments and Contingencies — EPA New Source Review,” “Legal Proceedings,” and “Ongoing Investigations,” respectively, which are incorporated herein by reference.

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

Information required by Item 4 is omitted pursuant to General Instruction I(2)(c) to Form 10-K.

PART II

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

All of our common stock is owned by Westar Energy and is not traded.

ITEM 6. SELECTED FINANCIAL DATA

	For the Year Ended December 31,				
	2003	2002	2001	2000	1999
	(In Thousands)				
Income Statement Data:					
Sales	$ 709,654	$ 695,524	$ 631,391	$ 685,673	$ 638,340
Income from operations before accounting change	66,627	59,539	37,301	86,708	84,261

	As of December 31,				
	2003	2002	2001	2000	1999
	(In Thousands)				
Balance Sheet Data:					
Total assets	$ 2,980,229	$ 3,006,393	$ 2,930,044	$ 2,988,573	$ 2,989,710
Long-term debt (a)	549,604	684,486	684,360	684,366	684,271

(a) In 2003, we repaid $135.0 million of our 7.6% first mortgage bonds that were due December 15, 2003.

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

INTRODUCTION

We are a rate-regulated electric utility in Kansas and a wholly owned subsidiary of Westar Energy. We provide rate-regulated electric service, together with the electric utility operations of Westar Energy, using the name "Westar Energy." 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 business by improving customer service, continuing to expand our wholesale sales, improving credit quality and improving our relationships with regulators, shareholders, employees and other interested parties.

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 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.

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 $22.7 million.

We are allocated our share of revenues from energy marketing activities that are jointly entered into with Westar Energy based on actual fuel burned at our generating facilities. The amount of actual fuel burned by a given generating facility is largely determined by utilizing the most economical units first. 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. 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 trading 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.

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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	$ 3,467
Less contracts realized or otherwise settled during the period	4,905
Plus fair value of new contracts entered into during the period	3,452
Fair value of contracts outstanding at the end of the period	$ 2,014

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				
Sources of Fair Value	Total Fair Value	Maturity Less Than 1 Year	Maturity 1-3 Years	Maturity 4-5 Years	Maturity in Excess of 5 Years
			(In Thousands)		
Prices actively quoted (futures)	$ 2,807	$ 2,807	$ —	$ —	$ —
Prices provided by other external sources (swaps and forwards)	(794)	(919)	125	—	—
Prices based on the Black Option Pricing model (options and other) (a)	1	1	—	—	—
Total fair value of contracts outstanding	$ 2,014	$ 1,889	$ 125	$ —	$ —

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

OPERATING RESULTS

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 outside our service territory, the cost of fuel and purchased power, price volatility and available generation capacity.

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2003 compared to 2002: Changes in results of operations are as follows:

	Year Ended December 31,			
	2003	2002	Change	% Change
	(In Thousands)			
SALES:				
Residential	$ 220,929	$ 223,339	$ (2,410)	(1.1)
Commercial	169,670	170,847	(1,177)	(0.7)
Industrial	153,463	152,915	548	0.4
Subtotal	544,062	547,101	(3,039)	(0.6)
Network integration (a)	29,794	30,068	(274)	(0.9)
Other (b)	22,843	23,444	(601)	(2.6)
Total retail	596,699	600,613	(3,914)	(0.7)
Wholesale	112,955	94,911	18,044	19.0
Total Sales	709,654	695,524	14,130	2.0
OPERATING EXPENSES:				
Fuel used for generation	135,907	132,431	3,476	2.6
Purchased power	42,068	38,300	3,768	9.8
Operating and maintenance	221,667	215,796	5,871	2.7
Depreciation and amortization	90,604	93,934	(3,330)	(3.5)
Selling, general and administrative	70,737	81,249	(10,512)	(12.9)
Total Operating Expenses	560,983	561,710	(727)	(0.1)
INCOME FROM OPERATIONS	$ 148,671	$ 133,814	$ 14,857	11.1

(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 $32.7 million. This amount, less $2.9 million that was retained by the SPP as administration cost, was returned to us as revenues. In 2002, our transmission costs were approximately $32.9 million with an administration cost of $2.9 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 because this activity is unrelated to electricity we generate.

	2003	2002	Change	% Change
	(Thousands of MWh)			
Residential	2,842	2,889	(47)	(1.6)
Commercial	2,685	2,675	10	0.4
Industrial	3,459	3,397	62	1.8
Other	44	44	—	—
Total retail	9,030	9,005	25	0.3
Wholesale	3,156	3,831	(675)	(17.6)
Total	12,186	12,836	(650)	(5.1)

Retail sales revenues declined due primarily to the accrual of approximately $1.7 million to be refunded to customers in 2005 and 2006 pursuant to a KCC order. The remainder of the decline in retail sales revenues was because of the effect of the weather on usage of electricity by residential customers, which caused residential sales volumes to decline. Commercial and industrial sales revenues showed slight decreases while sales volumes remained increased slightly compared to 2002.

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

The primary reason our fuel expense increased is because of the higher cost of natural gas and oil used for generation. While we used less MMBtu of natural gas and oil during 2003 than we did during 2002, we spent $2.2 million more for natural gas and oil during 2003 than we spent during the prior year. 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. Our peaking units are primarily natural gas burning units; the higher price of natural gas was the primary factor in determining whether it was more economical to purchase power or to operate our peaking units.

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Selling, general and administrative expenses declined in 2003, due primarily to a reduction in incremental administrative expenses incurred in 2002 that were allocated to us for Westar Energy's work force reduction. 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 increased due primarily to increased general maintenance expenses at our generating facilities in 2003. General maintenance expenses increased by $4.8 million, partially offsetting the declines in selling, general and administrative and depreciation expenses.

2002 compared to 2001: Changes in results of operations are as follows:

	Year Ended December 31,			
	2002	2001	Change	% Change
	(In Thousands)			
SALES:				
Residential	$ 223,339	$ 222,427	$ 912	0.4
Commercial	170,847	175,899	(5,052)	(2.9)
Industrial	152,915	155,990	(3,075)	(2.0)
Subtotal	547,101	554,316	(7,215)	(1.3)
Network integration (a)	30,068	—	30,068	—
Other (b)	23,444	24,970	(1,526)	(6.1)
Total retail	600,613	579,286	21,327	3.7
Wholesale	94,911	52,105	42,806	82.2
Total Sales	695,524	631,391	64,133	10.2
OPERATING EXPENSES:				
Fuel used for generation	132,431	140,637	(8,206)	(5.8)
Purchased power	38,300	24,805	13,495	54.4
Operating and maintenance	215,796	194,102	21,694	11.2
Depreciation and amortization	93,934	105,136	(11,202)	(10.7)
Selling, general and administrative	81,249	73,441	7,808	10.6
Total Operating Expenses	561,710	538,121	23,589	4.4
INCOME FROM OPERATIONS	$ 133,814	$ 93,270	$ 40,544	43.5

(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 $32.9 million. This amount, less $2.9 million that was retained by the SPP as administration cost, was returned to us as revenues. 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 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 because this activity is unrelated to electricity we generate.

	2002	2001	Change	% Change
	(Thousands of MWh)			
Residential	2,889	2,734	155	5.7
Commercial	2,675	2,632	43	1.6
Industrial	3,397	3,488	(91)	(2.6)
Other	44	44	—	—
Total retail	9,005	8,898	107	1.2
Wholesale	3,831	2,479	1,352	54.5
Total	12,836	11,377	1,459	12.8

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 volumes were similarly affected by favorable weather conditions, however, the lower retail rates had a larger impact on commercial customers, causing the larger reduction in commercial sales revenues. Industrial sales revenues decreased primarily because of weaker economic conditions experienced in our service territory, principally associated with the downturn in the aircraft industry.

Wholesale revenues increased approximately $12.9 million as a result of the increase in wholesale sales volumes. Revenues attributable to the increase in wholesale sales volumes were partially offset by lower market prices. In addition, on January 1, 2001, we adopted SFAS No. 133 that required that we report a $21.4 million gain in 2001 on certain derivative contracts as a cumulative effect of a change in accounting principle rather than include the gain in revenues.

Nuclear fuel expense decreased $4.3 million in 2002 as compared to 2001. Because there was no refueling outage of Wolf Creek during 2001, the plant used more fuel during 2001. The remainder of the decline in fuel expense was due primarily to using more natural gas in 2001 than in 2002 at a higher average fuel price. Purchased power expense increased due primarily to the 2002 Wolf Creek refueling outage.

Selling, general and administrative expenses increased due primarily to employee severance costs related to a work force reduction at Westar Energy that were allocated to us. Operating and maintenance expense increased due primarily to $32.9 million in charges associated with the network integration transmission tariff as discussed in "— Other Information — Network Integration Transmission Service." General maintenance expense at our generating facilities declined $7.6 million, or 22%, 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 $11.2 million due primarily to changes in depreciation rates as ordered by the KCC on July 25, 2001 and on April 1, 2002.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Most of our cash requirements consist of capital and maintenance expenditures designed to improve and maintain facilities that provide electric service and meet future customer service requirements. Our ability to provide the cash or debt to fund our capital expenditures depends on many things, including available resources, our financial condition and current market conditions.

We expect our internally generated cash to be sufficient to fund operations and debt service payments. We do not maintain independent short-term credit facilities and rely on Westar Energy for short-term cash needs. If Westar Energy is unable to borrow under its credit facilities, we could have a short-term liquidity problem that could require us to obtain a credit facility for our short-term cash needs and that could result in higher borrowing costs.

Capital Resources

The Debt Reduction Plan provides for a systematic disposal of Westar Energy's non-utility and non-core assets and the planned issuance of Westar Energy equity securities. The net proceeds of these transactions have been and will be used to reduce debt. Westar Energy may reduce its and our debt pursuant to terms stated in the debt agreements or through open market purchases or tender offers. Westar Energy expects to issue equity securities in 2004 in private transactions, public offerings or both.

Our mortgage prohibits additional first mortgage bonds from being issued (except in connection with certain refundings) unless our net earnings before income taxes and accounting change 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 of our 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 first mortgage bonds could be issued under the most restrictive provisions in the mortgage.

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 increased $17.2 million to $154.8 million in 2003 from $137.6 million in 2002. This increase was mostly attributable to favorable changes in our working capital requirements, primarily restricted cash and accounts payable, partially offset by an increase in accounts receivable.

Cash Flows used in Investing Activities

In general, cash used for investing purposes relates to the growth and maintenance of our utility operations. Our business is capital intensive and requires significant investment in plant on an annual basis. We spent $106.0 in 2003, $78.3 million in 2002, and $82.8 in 2001 on net additions to property, plant and equipment.

Cash Flows used in Financing Activities

Net cash used in financing activities totaled $29.1 million for the year ended December 31, 2003 as compared to $40.5 million for the same period in 2002. In 2003, cash was used to retire long-term debt and to pay $100.0 million in dividends to Westar Energy. The cash used to retire long-term debt was from funds placed in a trust in 2002. Partially offsetting this decrease was a reduction in net advances from Westar Energy.

Net cash used in financing activities totaled $40.5 million for the year ended December 31, 2002 as compared to $6.1 million for the same period in 2001 due primarily to $135.0 million of funds that were irrevocably deposited with the bond trustee to provide for the repayment of our 7.6% first mortgage bonds that were due December 15, 2003.

Future Cash Requirements

We believe that internally generated funds and borrowings from Westar Energy will be sufficient to meet our operating and capital expenditure requirements and debt service payments. The Debt Reduction Plan requires us to pay our share of the combined rebates to retail customers totaling $10.5 million on May 1, 2005 and $10.0 million on January 1, 2006. Westar Energy and we believe these rebates can be funded with internally generated cash flow and available borrowing capacity under Westar Energy's revolving credit facility.

If Westar Energy is required to update emissions controls or take other remedial action at Jeffrey Energy Center as a result of the EPA's investigation of Westar Energy, the costs could be material. Westar Energy may also have to pay fines or penalties or make significant capital or operational expenditures related to the notice of violation Westar Energy 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. We anticipate that we would be allocated a portion of any of these potential costs.

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 and existing Westar Energy revolving credit facility.

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

	Replacements	Additional Capacity	New Customer Construction	Nuclear Fuel	Total
			(In Thousands)		
2003	$ 45,965	$ 1,140	$ 18,560	$ 19,914	$ 85,579
2004	53,507	6,470	17,505	21,346	98,828
2005	54,296	12,643	17,697	1,086	85,722
2006	73,889	7,990	17,980	22,638	122,497

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	$ —
2005	65,000
2006	100,000
2007	—
2008	—
Thereafter	384,604
	$ 549,604

Contractual Cash Obligations

In the course of our business activities, we enter into a variety of contractual obligations. 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.

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

Contractual Obligations	Total	2004	2005 – 2006 (b)	2007 - 2008	Thereafter
			(In Thousands)		
Long-term debt (a)	$ 549,604	$ —	$ 165,000	$ —	$ 384,604
Operating leases (c)	569,187	38,136	88,376	95,501	347,174
Fossil fuel (d)	500,558	52,054	90,878	60,023	297,603
Nuclear fuel (e)	177,904	23,710	25,338	22,856	106,000
Unconditional purchase obligations	19,074	14,177	4,895	2	—
Total contractual obligations, including adjusted long-term debt	$ 1,816,327	$ 128,077	$ 374,487	$ 178,382	$ 1,135,381

(a) See Note 9 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 office space, operating facilities, office equipment and operating equipment.
(d) Coal and natural gas commodity and transportation contracts.
(e) Uranium concentrates, conversion and enrichment.

Debt Covenants

Some of Westar Energy's debt instruments contain restrictions that require it to maintain various coverage and leverage ratios as defined in the agreements. Westar Energy's calculations of these ratios are performed in accordance with its debt agreements and are used solely to determine compliance with its various debt covenants. Westar Energy was 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 our combined 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 4 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 4 of the Notes to Consolidated Financial Statements, "Accounts Receivable and Variable Interest Entities" for additional information.

Debt Financings

On June 6, 2002, Westar Energy 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 Westar Energy has not refinanced or provided for the payment of its 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 our first mortgage bonds. The proceeds of the term loan were used to retire the existing $400.0 million revolving credit facility of Westar Energy with an outstanding principal balance of $380.0 million, to provide for the repayment at maturity of $135.0 million principal amount of our first mortgage bonds that were due December 15, 2003 together with accrued interest, to repurchase approximately $45.0 million of Westar Energy's outstanding unsecured notes and to pay customary fees and expenses of the transactions.

In February 2004, Westar Energy repaid the remaining balance of $114.1 million under its $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 its monitored services businesses.

On March 12, 2004, Westar Energy replaced its $150.0 million revolving credit facility discussed above with a new secured credit agreement providing for $300.0 million revolving credit capacity. The new credit agreement matures on March 12, 2007. All loans under the credit agreement are secured by our first mortgage bonds.

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Capital Structure

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

	2003	2002
Shareholder’s equity	66%	62%
Long-term debt	34%	38%
Total	100%	100%

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 Westar Energy’s and 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 Westar Energy and us a speculative liquidity rating of SGL-3, which reflects its view that Westar Energy has “adequate” liquidity. On January 5, 2004, S&P affirmed its ratings for Westar Energy and us and revised its outlook for us from developing to positive. On March 1, 2004 Fitch raised its ratings for Westar Energy and us 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. We 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 accounts receivable discussed in Note 4 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 derivative contracts 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

City of Wichita Franchise

On February 10, 2004, the Wichita city council approved a ten-year renewal of the franchise pursuant to which we provide 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 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 our zone were approximately $32.7 million. This amount, less $2.9 million that was retained by the SPP as administration cost, was returned to us as revenues. In 2002, our transmission costs were approximately $32.9 million with an administration cost of $2.9 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 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 a 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 $316.7 million. Of this amount, $155.8 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 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. We presently own 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 income will be lower than our historical net 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 $7.5 million included in accumulated depreciation that has been reclassified to other assets. At December 31, 2003, we had $2.1 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 14 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

Westar Energy and we jointly 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 some of 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 5 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.

Market Price Risks

Our hedging and trading activities involve risks, including commodity 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.

Interest rate risk represents the risk of loss associated with movements in market interest rates. In the future, we may 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 and system 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 are exposed to commodity price changes and use derivative contracts for non-trading purposes and a mix of various fuels 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 a 34% increase in the average price per MWh of electricity purchased for utility operations. The volatility in the purchased power market 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 the price of our purchased power from 2003 to 2004, given the amount of power purchased for utility operations during 2003, we would have exposure of approximately $1.5 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 fuels, 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 31% increase, or $1.07 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 12.3 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 fuels as the market and our equipment allow, primarily by using oil in our natural gas burning facilities. During 2003, we increased our oil usage by 14.5 million MMBtu compared to the amount burned in 2002. Although the average cost of oil used for utility operations increased $0.68 per MMBtu, or approximately 27%, compared to the average cost in 2002, it was $1.31 per MMBtu cheaper than the average cost of the natural gas we burned.

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 $46.4 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 income from operations before income taxes on an annualized basis by approximately $0.5 million.

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, II, III, IV, and V.

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INDEPENDENT AUDITORS' REPORT

To the Board of Directors of
Kansas Gas and Electric Company
Topeka, Kansas

We have audited the accompanying consolidated balance sheets of Kansas Gas and Electric Company (the Company), a wholly-owned subsidiary of Westar Energy, Inc., as of December 31, 2003 and 2002, and the related consolidated statements of income and comprehensive income, cash flows and shareholder's equity, for each of the three years in the period ended December 31, 2003. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the 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, 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.

As discussed in Note 2 and Note 14 to the financial statements, the Company changed its method of accounting for asset retirement obligations in 2003 and accounting for derivative contracts and hedging activities in 2001.

Deloitte & Touche LLP
Kansas City, Missouri
March 15, 2004

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KANSAS GAS AND ELECTRIC COMPANY
CONSOLIDATED BALANCE SHEETS
(Dollars in Thousands)

	As of December 31,	
	2003	2002
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 6,321	$ 6,150
Restricted cash	22	145,282
Accounts receivable, net	80,771	49,697
Inventories and supplies	66,930	65,555
Energy trading contracts	8,688	11,039
Deferred tax assets	1,064	—
Prepaid expenses	24,657	22,668
Other	1,435	2,531
Total Current Assets	189,888	302,922
PROPERTY, PLANT AND EQUIPMENT, NET	2,362,371	2,368,155
OTHER ASSETS:		
Regulatory assets	316,670	230,679
Nuclear decommissioning trust	80,075	63,522
Energy trading contracts	154	4,525
Other	31,071	36,590
Total Other Assets	427,970	335,316
TOTAL ASSETS	$ 2,980,229	$ 3,006,393
LIABILITIES AND SHAREHOLDER’S EQUITY		
CURRENT LIABILITIES:		
Current maturities of long-term debt	$ —	$ 135,000
Accounts payable	42,231	31,182
Payable to affiliates	25,909	24,077
Accrued interest	8,342	8,480
Accrued taxes	28,059	22,876
Accrued liabilities	3,144	2,432
LaCygne 2 lease	32,543	32,381
Energy trading contracts	6,799	9,480
Deferred tax liability	—	13,470
Other	7,338	6,929
Total Current Liabilities	154,365	286,307
LONG-TERM LIABILITIES:		
Long-term debt, net	549,604	549,486
Deferred income taxes and investment tax credits	731,736	714,256
Deferred gain from sale-leaseback	150,810	162,638
Asset retirement obligation	80,695	—
Nuclear decommissioning	80,075	63,522
Energy trading contracts	29	2,616
Other	147,337	108,187
Total Long-Term Liabilities	1,740,286	1,600,705
COMMITMENTS AND CONTINGENCIES (NOTE 12)		
SHAREHOLDER’S EQUITY:		
Common stock, without par value; authorized and issued 1,000 shares	1,065,634	1,065,634
Accumulated other comprehensive income, net	—	430
Retained earnings	19,944	53,317
Total Shareholder’s Equity	1,085,578	1,119,381
TOTAL LIABILITIES AND SHAREHOLDER’S EQUITY	$ 2,980,229	$ 3,006,393

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

KANSAS GAS AND ELECTRIC COMPANY

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

	Year Ended December 31,		
	2003	2002	2001
SALES	$ 709,654	$ 695,524	$ 631,391
OPERATING EXPENSES:			
Fuel and purchased power	177,975	170,731	165,442
Operating and maintenance	221,667	215,796	194,102
Depreciation and amortization	90,604	93,934	105,136
Selling, general and administrative	70,737	81,249	73,441
Total Operating Expenses	560,983	561,710	538,121
INCOME FROM OPERATIONS	148,671	133,814	93,270
OTHER INCOME (EXPENSE):			
Other income	13,921	2,784	3,193
Other expense	(14,412)	(14,185)	(12,518)
Total Other Income (Expense)	(491)	(11,401)	(9,325)
Interest Expense	(54,550)	(46,795)	(48,244)
INCOME FROM OPERATIONS BEFORE INCOME TAXES AND ACCOUNTING CHANGE	93,630	75,618	35,701
Income tax benefit (expense)	(27,003)	(16,079)	1,600
INCOME FROM OPERATIONS BEFORE ACCOUNTING CHANGE	66,627	59,539	37,301
Cumulative effect of accounting change, net of tax of $8,520	—	—	12,898
NET INCOME	$ 66,627	$ 59,539	$ 50,199
OTHER COMPREHENSIVE INCOME, NET OF TAX:			
Unrealized holding gain (loss) on cash flow hedges	$ 2,421	$ 17,644	$ (20,064)
Adjustment for (gain) loss included in net income	(3,135)	1,374	1,760
Income tax benefit (expense) related to items of other comprehensive income	284	(7,565)	7,281
Total other comprehensive (loss) gain, net of tax	(430)	11,453	(11,023)
COMPREHENSIVE INCOME	$ 66,197	$ 70,992	$ 39,176

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

KANSAS GAS AND ELECTRIC COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS
(Dollars in Thousands)

	Year Ended December 31,		
	2003	2002	2001
CASH FLOWS FROM (USED IN) OPERATING ACTIVITIES:			
Net income	$ 66,627	$ 59,539	$ 50,199
Adjustments to reconcile net income to net cash provided by operating activities:			
Cumulative effect of accounting change	—	—	(12,898)
Depreciation and amortization	90,604	93,934	105,136
Amortization of nuclear fuel	12,410	13,142	16,965
Amortization of deferred gain from sale-leaseback	(11,828)	(11,828)	(11,828)
Corporate owned life insurance	(39,782)	(32,710)	(40,902)
Net deferred taxes	7,027	(2,224)	(12,001)
Net changes in energy trading assets and liabilities	739	4,338	14,327
Loss on sale of property	—	1,423	—
Changes in working capital items:			
Restricted cash	—	(10,282)	—
Accounts receivable, net	(31,074)	(5,336)	41,441
Inventories and supplies	(1,375)	(24)	(19,143)
Prepaid expenses and other	(891)	(1,036)	(1,814)
Accounts payable	11,049	(20,201)	1,599
Accrued and other current liabilities	6,327	95	10,585
Changes in other, assets	5,714	29,462	(27,873)
Changes in other, liabilities	39,275	19,263	(6,664)
Cash flows from operating activities	154,822	137,555	107,129
CASH FLOWS FROM (USED IN) INVESTING ACTIVITIES:			
Additions to property, plant and equipment	(105,957)	(78,300)	(82,751)
Investment in corporate-owned life insurance	(19,599)	(19,399)	(19,852)
Proceeds from sale of property	—	1,205	—
Cash flows used in investing activities	(125,556)	(96,494)	(102,603)
CASH FLOWS FROM (USED IN) FINANCING ACTIVITIES:			
Retirements of long-term debt	(135,005)	—	(130)
Funds in trust for debt repayment	145,260	(135,000)	—
Net borrowings against cash surrender value of corporate-owned life insurance	58,818	53,102	58,309
Advances from parent company, net	1,832	41,423	35,758
Dividends to parent company	(100,000)	—	(100,000)
Cash flows used in financing activities	(29,095)	(40,475)	(6,063)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	171	586	(1,537)
CASH AND CASH EQUIVALENTS:			
Beginning of period	6,150	5,564	7,101
End of period	$ 6,321	$ 6,150	$ 5,564
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION:			
CASH PAID FOR:			
Interest on financing activities, net of amount capitalized	$ 36,396	$ 56,887	$ 46,821
Income taxes	—	—	—

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

KANSAS GAS AND ELECTRIC COMPANY

CONSOLIDATED STATEMENTS OF SHAREHOLDER'S EQUITY
(Dollars in Thousands)

	Year Ended December 31,		
	2003	**2002**	**2001**
Common Stock	$1,065,634	$1,065,634	$1,065,634
Accumulated other comprehensive income:			
Beginning balance	430	(11,023)	—
Unrealized holding (loss) gain on cash flow hedges	2,421	17,644	(20,064)
Adjustment for loss (gain) included in net income	(3,135)	1,374	1,760
Tax benefit (expense)	284	(7,565)	7,281
Accumulated other comprehensive income	—	430	(11,023)
Retained Earnings:			
Beginning balance	53,317	(6,222)	43,579
Net income	66,627	59,539	50,199
Dividends to parent company	(100,000)	—	(100,000)
Ending balance	19,944	53,317	(6,222)
Total Shareholder's Equity	$1,085,578	$1,119,381	$1,048,389

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

KANSAS GAS AND ELECTRIC COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2003

1. DESCRIPTION OF BUSINESS

Kansas Gas and Electric Company is a rate-regulated electric utility incorporated in 1990 in the state of Kansas. Unless the context otherwise indicates, all references in this Annual Report on Form 10-K to “the company,” “KGE,” “we,” “us,” “our” and similar words are to Kansas Gas and Electric Company. We are a wholly owned subsidiary of Westar Energy, Inc. (Westar Energy) and we provide rate-regulated electric service, together with the electric utility operations of Westar Energy, using the name Westar Energy. We provide electric generation, transmission and distribution services to approximately 298,000 customers in south-central and southeastern Kansas, including the Wichita metropolitan area. Our corporate headquarters are located in Wichita, Kansas.

We own 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.

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. 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, valuation of our energy trading portfolio, intangible assets, income taxes, nuclear decommissioning of Wolf Creek, asset retirement obligations, environmental issues, contingencies and litigation. Actual results may differ from those estimates under different assumptions or conditions.

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 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	$ 155,800	$ 153,242
Debt reacquisition costs	18,074	20,701
Deferred plant costs	28,532	29,037
2002 ice storm costs	9,898	9,048
Asset retirement obligations	70,455	—
Wolf Creek outage	13,645	7,072
KCC depreciation	14,295	6,253
Other regulatory assets	5,971	5,326
Total regulatory assets	$ 316,670	$ 230,679
Total regulatory liabilities	$ 6,374	$ 4,075

- **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 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 Kansas Corporation Commission (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 14, "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 non-legal 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, the removal component of our non-legal asset retirement obligation 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.

Inventories and Supplies

Inventories and supplies 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 5.3% in 2003, 6.0% in 2002 and 8.6% in 2001. The cost of additions to utility plant and replacement units of property is capitalized. AFUDC capitalized into construction in progress was $0.9 million in 2003, $1.0 million in 2002 and $1.4 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.

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 2.2% during 2003, 2.4% during 2002 and 2.8% 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 $18.0 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.

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

	Years
Fossil fuel generating facilities	6 to 68
Nuclear fuel generating facility	38 to 45
Transmission facilities	28 to 65
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)	$ 767.7	$ 708.4
Borrowings against policies	(755.0)	(696.2)
COLI, net	$ 12.7	$ 12.2

(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 other income approximated $0.2 million in 2003, $2.1 million in 2002 and $0.3 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 $22.7 million.

We are allocated our share of revenues from energy marketing activities that are jointly entered into with Westar Energy based on actual fuel burned at our generating facilities. The amount of actual fuel burned by a given generating facility is largely determined by utilizing the most economical units first. 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. 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 trading 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.

Income Taxes

Our consolidated financial statements use the liability method to reflect deferred 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.

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 affect on our consolidated results of operations, financial position or cash flows.

In October 2002, 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 Activites." 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 not 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 derivative contracts 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 on 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 5, "Financial Instruments, Energy Trading and Risk Management," for additional information on the effects of the accounting change.

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 November 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.

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 4, “Accounts Receivable and Variable Interest Entities.” We were not affected by FIN 46R.

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 $53.1 million and $58.3 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 The Debt Reduction Plan

February 6, 2003 Debt Reduction Plan

On February 6, 2003, Westar Energy filed a debt reduction plan (the Debt Reduction Plan) with the KCC in response to the KCC’s order that would have required Westar Energy to reduce debt to $1.67 billion by August 1, 2003. In the Debt Reduction Plan, Westar Energy outlined its plans for paying down debt and simplifying its 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, Westar Energy had terminated certain agreements and reversed certain intercompany transactions that might have prevented or impeded returning to being a stand-alone electric utility.
- Westar Energy had sold a portion of its ONEOK, Inc. (ONEOK) stock and raised $300.0 million, the net proceeds of which it anticipated using to repurchase or provide for the repayment of its 6.25% senior unsecured notes that were putable and callable on August 15, 2003 (the putable/callable notes) and a portion of its 6.875% senior unsecured notes.
- Westar Energy’s board of directors had established a dividend policy that reduced its quarterly dividend on its 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 Westar Energy's interests in monitored security businesses.
- The sale of all of Westar Energy's remaining ONEOK stock.
- The potential issuance of Westar Energy 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 Westar Energy 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.

July 25, 2003 KCC Order

On July 21, 2003, Westar Energy and 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:

- Westar Energy will fully implement the Debt Reduction Plan by December 31, 2004, unless prevented by events beyond its control, in which case the KCC may extend the deadline for implementation upon a proper showing by Westar Energy.
- Westar Energy will reduce its 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 Westar Energy reduce utility debt to $1.67 billion by August 1, 2003.
- Westar Energy and we will file rate cases with the KCC, 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.
- Westar Energy and we will pay to our Kansas jurisdictional customers combined rebates totaling $10.5 million on May 1, 2005 and $10.0 million on January 1, 2006.
- Westar Energy and we will also pay a rebate to customers for any amounts Westar Energy may recover from David C. Wittig, Westar Energy's former president, chief executive officer and chairman, and Douglas T. Lake, Westar Energy's 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 electric rates during calendar years 1998 through 2002, net of costs Westar Energy incurs to recover the funds. See Note 15 of the Notes to Consolidated Financial Statements, "Legal Proceedings," for more information about Westar Energy's efforts to recover compensation from Mr. Wittig and Mr. Lake.
- Westar Industries, Inc. (Westar Industries), a wholly owned subsidiary of Westar Energy, 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.

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 $1.7 million for revenue to be refunded, which is included in other liabilities on our consolidated balance sheets.

4. 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	$143,443	$ 142,688
Allowance for uncollectable accounts	(5,415)	(5,978)
Unbilled energy receivable	22,743	22,987
Accounts receivable sale program	(80,000)	(110,000)
Accounts receivable, net	$ 80,771	$ 49,697

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 our combined 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. The provisions of this interpretation became effective upon issuance. We were not affected by FIN 46R.

5. 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)	$ 505,988	$ 505,993	$ 519,099	$ 510,389

(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 presented herein 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.

Westar Energy and we jointly use derivative financial and physical contracts 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. 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 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 fuels 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 fuels, 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 fuels 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 could 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.

Westar Energy and we jointly use derivative financial contracts to reduce our exposure to certain fluctuations in some commodity prices, interest rates, and other market risks. With respect to some financial contracts we enter, 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 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, Westar Energy and we entered into hedging relationships to manage commodity price risk associated with future natural gas purchases. Initially, Westar Energy entered into futures and swap contracts with terms extending through July 2004 to hedge price risk for a portion of anticipated natural gas fuel requirements for generation facilities. Westar Energy has designated these hedging relationships as cash flow hedges.

In 2002, due to the increased availability of 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 8,280,000 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 $2.8 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 $1.8 million, of which $2.0 million had previously been recognized in other comprehensive income.

6. 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	$ 3,829,091	$ 3,771,694
Accumulated depreciation	(1,531,806)	(1,443,353)
	2,297,285	2,328,341
Construction work in progress	35,818	18,050
Nuclear fuel, net	29,198	21,694
Net utility plant	2,362,301	2,368,085
Non-utility plant in service	70	70
Net property, plant and equipment	$ 2,362,371	$ 2,368,155

Depreciation expense on property, plant and equipment was $70.5 million in 2003, $73.8 million in 2002 and $85.0 million in 2001.

7. 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	74,838	36,364	147.0	20
Jeffrey 2	(b)	May	1980	72,896	33,921	147.0	20
Jeffrey 3	(b)	May	1983	102,594	50,425	149.0	20
Jeffrey wind 1	(b)	May	1999	208	42	0.1	20
Jeffrey wind 2	(b)	May	1999	207	42	0.1	20
Wolf Creek	(c)	Sept.	1985	1,407,696	576,649	548.0	47

(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.

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 us 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 on our consolidated financial statements.

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8. SHORT-TERM BORROWINGS

We had no short-term borrowings outstanding at December 31, 2003 and 2002. Our short-term liquidity needs are met from cash advances by Westar Energy.

Westar Energy has an arrangement with certain banks to provide a revolving credit facility on a committed basis totaling $150.0 million. The facility is secured by our first mortgage bonds and matures on June 6, 2005, provided that if Westar Energy has not refinanced or provided for the payment of its 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 million remaining capacity under this facility.

On March 12, 2004, Westar Energy replaced its $150.0 million revolving credit facility with a new secured credit agreement providing for $300.0 million revolving credit capacity. The new credit agreement matures on March 12, 2007. For additional information, see Note 10, “Debt Financings.”

See Note 9, “Long-term Debt,” for a discussion of covenants applicable to Westar Energy’s credit facilities.

9. LONG-TERM DEBT

The amount of our first mortgage bonds authorized by our Mortgage and Deed of Trust (Mortgage) dated April 1, 1940, as supplemented, is limited to a maximum of $2.0 billion. Amounts of additional bonds that may be issued are subject to property, earnings and certain restrictive provisions of the Mortgage. Electric plant is subject to the lien of the Mortgage except for transportation equipment. As of December 31, 2003, approximately $889.0 million principal amount of additional first mortgage bonds could be issued under the most restrictive provisions in the mortgage.

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

	2003	2002
	(In Thousands)	
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 discount (b)	(2,824)	(2,947)
Long-term debt due within one year	—	(135,000)
Long-term debt, net	$549,604	$ 549,486

(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.

Debt Covenants

Some of Westar Energy’s debt instruments contain restrictions that require it to maintain various coverage and leverage ratios as defined in the agreements. Westar Energy’s calculations of these ratios are performed in accordance with its debt agreements and are used solely to determine compliance with its various debt covenants. Westar Energy was in compliance with these covenants as of December 31, 2003.

Maturities

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

Year	Principal Amount
	(In Thousands)
2004	$ —
2005	65,000
2006	100,000
2007	—
2008	—
Thereafter	384,604
	$ 549,604

Our interest expense on long-term debt was $46.5 million in 2003, $46.8 million in 2002 and $48.2 million in 2001.

10. DEBT FINANCINGS

On June 6, 2002, Westar Energy 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 Westar Energy has not refinanced or provided for the payment of its 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 our first mortgage bonds. The proceeds of the term loan were used to retire the existing $400.0 million revolving credit facility of Westar Energy with an outstanding principal balance of $380.0 million, to provide for the repayment at maturity of $135.0 million principal amount of our first mortgage bonds that were due December 15, 2003 together with accrued interest, to repurchase approximately $45.0 million of Westar Energy’s outstanding unsecured notes and to pay customary fees and expenses of the transactions.

In February 2004, Westar Energy repaid the remaining balance of $114.1 million under its $585.0 million term loan that was due in 2005 with internally generated cash and a portion of the proceeds received from the sale in 2004 of its monitored services businesses.

On March 12, 2004, Westar Energy replaced its $150.0 million revolving credit facility discussed above with a new secured credit agreement providing for $300.0 million revolving credit capacity. The new credit agreement matures on March 12, 2007. All loans under the credit agreement are secured by our first mortgage bonds.

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11. EMPLOYEE BENEFIT PLANS

Pension and Post-retirement Benefits

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.

	Pension Benefits		Post-retirement Benefits	
At December 31,	2003	2002	2003	2002
	(In Thousands)			
Change in Benefit Obligation:				
Benefit obligation, beginning of year	$ 44,519	$ 34,118	$ 4,857	$ 3,680
Service cost	2,545	2,207	218	166
Interest cost	2,928	2,613	289	272
Plan participants' contributions	—	—	111	—
Benefits paid	(729)	(649)	(349)	(187)
Actuarial losses (gains)	664	5,946	329	926
Curtailments, settlements and special term benefits	—	284	—	—
Benefit obligation, end of year	$ 49,927	$ 44,519	$ 5,455	$ 4,857
Change in Plan Assets:				
Fair value of plan assets, beginning of year	$ 22,276	$ 23,375	$ N/A	$ N/A
Actual return on plan assets	2,622	(2,206)	N/A	N/A
Employer contribution	2,459	1,756	N/A	187
Plan participants' contributions	—	—	N/A	N/A
Benefits paid	(558)	(649)	N/A	N/A
Settlements	—	—	N/A	(187)
Fair value of plan assets, end of year	$ 26,799	$ 22,276	$ N/A	$ —
Funded status	$ (23,128)	$ (22,243)	$ (5,455)	$ (4,857)
Unrecognized net (gain) loss	11,589	11,727	2,028	1,798
Unrecognized transition obligation, net	455	511	519	576
Unrecognized prior service cost	252	244	—	—
Post-measurement date adjustments	441	—	—	—
Prepaid (accrued) post-retirement benefit costs	$ (10,391)	$ (9,761)	$ (2,908)	$ (2,483)
Amounts Recognized in the Statement of Financial Position Consist Of:				
Accrued benefit liability	$ (10,391)	$ (9,761)	$ (2,908)	$ (2,483)
Additional minimum liability	(66)	(67)	N/A	N/A
Intangible asset	35	—	N/A	N/A
Accumulated other comprehensive income	31	67	N/A	N/A
Net amount recognized	$ (10,391)	$ (9,761)	$ (2,908)	$ (2,483)

At December 31,	Pension Benefits 2003	Pension Benefits 2002	Post-retirement Benefits 2003	Post-retirement Benefits 2002
	(In Thousands)			
Accumulated Benefit Obligation	$37,037	$ 31,795	$ N/A	$ N/A
Pension Plans With a Projected Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$49,927	$ 44,519	N/A	N/A
Accumulated benefit obligation	37,037	31,795	N/A	N/A
Fair value of plan assets	26,799	22,276	N/A	N/A
Pension Plans With an Accumulated Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$49,927	$ 44,519	N/A	N/A
Accumulated benefit obligation	37,037	31,795	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	$5,455	$4,857
Fair value of plan assets	N/A	N/A	N/A	N/A
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Benefit Obligation:				
Discount rate	6.20%	6.75%	6.20%	6.50%
Compensation rate increase	3.20%	Graded rates	N/A	N/A

WCNOC uses a measurement date of December 1 for the majority of its 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	$ 2,545	$ 2,207	$ 1,682	$ 218	$ 166	$ 128
Interest cost	2,928	2,613	2,221	289	272	244
Expected return on plan assets	(2,464)	(2,469)	(2,264)	—	—	—
Amortization of unrecognized transition obligation, net	57	57	57	58	57	57
Amortization of unrecognized prior service costs	31	27	24	—	—	—
Amortization of (gain) loss, net	603	21	(467)	99	73	34
Curtailments, settlements and special term benefits	—	284	(264)	—	—	—
Net periodic (benefit) cost	$ 3,700	$ 2,740	$ 989	$ 664	$ 568	$ 463
Weighted-Average Actuarial Assumptions used to Determine Net Periodic (Benefit) Cost:						
Discount rate	6.75%	7.25%	7.25%	6.50%	7.25%	7.75%
Expected long-term return on plan assets	9.00%	9.02%	9.25%	N/A	N/A	N/A
Compensation rate increase	Graded rates	Graded rates	Graded rates	N/A	N/A	N/A

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	9.0%	9.5%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	5.0%	5.0%
Year that the rate reaches the ultimate trend rate	2011	2011

Assumed health care cost trend rates have 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	$ 3	$ (3)
Effect on the present value of the accumulated projected benefit obligation	46	(44)

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 at the end of 2003 and 2002, and the target allocation for 2004, by asset category are as follows:

		Plan Assets	
Asset Category	**Target Allocation for 2004**	**2003**	**2002**
Pension Plans:			
Equity securities	50% - 70%	66%	59%
Debt securities	30% - 50%	33%	36%
Other	0%	1%	5%
Total		100%	100%

WCNOC's pension plan investment strategy supports the objective of the fund, 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. WCNOC delegates investment management to specialists in each asset class and where appropriate, provides 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.

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	$ 100	$ N/A	$ 200
Expected benefit payments:				
2004	$ 700	$ 100	$ N/A	$ 200
2005	800	100	N/A	200
2006	900	100	N/A	300
2007	1,100	100	N/A	400
2008	1,300	100	N/A	500
2009 - 2013	11,700	800	N/A	4,300

Savings Plans

WCNOC maintains a qualified 401(k) savings plan in which a majority of its employees participate. They match employees' contributions in cash up to specified maximum limits. WCNOC's contribution to the plan is deposited with a trustee and is invested at the direction of plan participants into one or more of the investment alternatives provided under the plan. Our portion of expense associated with WCNOC's matching contributions was $0.9 million for 2003, $0.8 million for 2002 and $0.8 million for 2001.

12. INCOME TAXES

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

	2003	2002	2001
		(In Thousands)	
Current income taxes:			
Federal	$(18,074)	$ 1,994	$(26,373)
State	(4,460)	404	(6,098)
Deferred income taxes:			
Federal	(4,921)	(16,325)	20,376
State	(1,486)	(4,284)	2,323
Investment tax credit amortization	1,938	2,132	2,852
Total	(27,003)	(16,079)	(6,920)
Less taxes classified in:			
Cumulative effect of accounting change	—	—	(8,520)
Total income tax (expense) benefit	$(27,003)	$(16,079)	$ 1,600

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

	December 31,	
	2003	2002
	(In Thousands)	
Deferred tax assets:		
Deferred gain on sale-leaseback	$ 66,448	$ 71,609
General business credit carryforward	7,602	7,779
Accrued liabilities	4,956	4,469
Disallowed plant costs	14,527	15,587
Long-term energy contracts	1,093	1,162
Other	24,525	25,281
Total deferred tax assets	$ 119,151	$ 125,887
Deferred tax liabilities:		
Accelerated depreciation	$ 384,612	$ 384,355
Acquisition premium	250,583	258,582
Deferred future income taxes	155,800	153,241
Investment tax credits	48,663	51,252
Other	10,165	6,183
Total deferred tax liabilities	$ 849,823	$ 853,613

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

	December 31,	
	2003	2002
	(In Thousands)	
Current deferred tax assets, net	$ 1,064	$ —
Current deferred tax liabilities, net	—	13,470
Non-current deferred tax liabilities, net	731,736	714,256
Net deferred tax liabilities	$730,672	$727,726

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	4.1	3.2	4.0
Amortization of investment tax credits	(2.1)	(2.8)	(8.0)
Corporate-owned life insurance policies	(13.3)	(16.5)	(35.4)
Accelerated depreciation flow through and amortization	5.3	2.0	10.3
Settlement of outstanding state income tax issue	(0.1)	(0.1)	(10.2)
Other	(0.1)	0.5	(0.2)
Effective income tax rate	28.8%	21.3%	(4.5)%

We are a member of Westar Energy's consolidated tax group. We file consolidated tax returns with Westar Energy. Westar Energy allocates to us our pro rata portion of consolidated income taxes based on our contribution to consolidated taxable income.

13. 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 $19.1 million at December 31, 2003, all of which has been committed. These commitments relate to purchase obligations issued and outstanding at year-end.

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

	Committed Amount
	(In Thousands)
2004	$ 14,177
2005	2,717
2006	2,178
2007	2
2008	—
Thereafter	—
	$ 19,074

Clean Air Act

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

Manufactured Gas Sites

We have been associated with a three former manufactured gas sites located in Kansas 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 governing all future work at these 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.

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 Westar Energy under Section 114 regarding projects and maintenance activities that have been conducted since 1980 at the three coal-fired plants it operates. On January 22, 2004, the EPA notified Westar Energy that certain projects completed at Jeffrey Energy Center violated pre-construction permitting requirements of the Clean Air Act.

Westar Energy is in discussions with the EPA concerning this matter but is unable to predict whether the EPA will take further enforcement action. Westar Energy 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 Westar Energy is required to pay any fines or penalties or update or install emissions controls at Jeffrey Energy Center 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 Westar Energy is assessed a penalty as a result of the EPA's allegation, the penalty could be material and may not be recovered in rates. We anticipate that we would be allocated a portion of any of these potential costs.

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 the 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 could 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 $499.3 million. 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 $1.2 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.

14. 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 Federal Energy Regulatory Commission (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 $7.5 million included in accumulated depreciation that has been reclassified to other assets. At December 31, 2003, we have $2.1 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.

15. LEGAL PROCEEDINGS

On June 13, 2003, Westar Energy filed a demand for arbitration with the American Arbitration Association asserting claims against David C. Wittig, Westar Energy’s former president, chief executive officer and chairman, and Douglas T. Lake, Westar Energy’s former executive vice president, chief strategic officer and member of the board, arising out of their previous employment with Westar Energy. Mr. Wittig and Mr. Lake have filed counterclaims against Westar Energy in the arbitration alleging substantial damages related to the termination of their employment and the publication of the report of the special committee of Westar Energy’s board of directors. Westar Energy intends to vigorously defend against these claims. Westar Energy is unable to predict the ultimate impact of this matter on its consolidated financial position, consolidated results of operations and cash flow.

We are involved in various 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, 12, and 15 for discussion of KCC regulatory proceedings, alleged violations of the Clean Air Act and an investigation by the FERC of certain of Westar Energy’s power transactions.

16. ONGOING INVESTIGATIONS

FERC Subpoena

On December 16, 2002, Westar Energy 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 Westar Energy conducted with third parties to facilitate power transfers between Westar Energy's system and its marketing operations. While these energy transactions do not apply to us, the FERC investigation includes all transactions of both Westar Energy and us. These transactions and other energy marketing and trading activities were recently reviewed in a KCC ordered audit of Westar Energy's 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.

Westar Energy has provided information to the FERC in response to the original subpoena, subsequent requests submitted through its 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. Westar Energy believes that our participation in these transactions and the conduct of its generation and transmission operations did not violate the FERC rules and regulations. However, Westar Energy is unable to predict the ultimate outcome of the investigation.

17. 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	$ 37,119
2002	28,895	38,316
2003	28,895	34,199
Future commitments:		
2004	$ 34,598	$ 38,136
2005	38,013	42,057
2006	42,287	46,319
2007	78,268	81,036
2008	12,609	14,465
Thereafter	331,441	347,174
Total future commitments	$ 537,216	$ 569,187

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

In 1987, we sold and leased back our 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. We remain responsible for our 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 represents 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 LaCygne 2 lease line on the consolidated balance sheets.

18. RELATED PARTY TRANSACTIONS

Our cash management function, including cash receipts and disbursements, is performed by Westar Energy. An intercompany account is used to record receipts and disbursements between Westar Energy and us and between WR Receivables Corporation and us. The net amount payable to affiliates was approximately $25.9 million at December 31, 2003 and the net amount payable from affiliates was approximately $24.1 million at December 31, 2002 as reflected on our consolidated balance sheets.

Westar Energy provides all employees we use. Certain operating expenses have been allocated to us from Westar Energy. 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. We believe such allocation procedures are reasonable.

We declared and paid dividends of $100.0 million to Westar Energy for the years ended December 31, 2003 and December 31, 2001. There were no dividends declared or paid in 2002.

Termination of Shared Services Agreement

Westar Energy maintains shared services agreements with ONEOK pursuant to which Westar Energy and ONEOK provide customer service functions to each other, including meter reading, customer billing and call center operations. ONEOK notified Westar Energy of its decision to terminate portions of the 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. Following termination, Westar Energy will allocate to us our portion of the expenses for providing these services internally. We expect the termination of this agreement to increase our annual costs for these services by approximately $4 million to $5 million.

Transactions Between Westar Energy's Monitored Services Business and Us

During the fourth quarter of 2001, we entered into an option agreement to sell an office building located in downtown Wichita, Kansas, to Westar Energy's monitored services business 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.

19. 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 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)		
2003				
Sales	$ 172,670	$ 172,165	$ 207,261	$ 157,558
Income from operations	36,364	34,988	58,069	19,250
Net income	17,024	15,984	28,923	4,696
2002				
Sales	$ 148,683	$ 161,873	$ 217,607	$ 167,361
Income from operations	5,546	19,093	76,638	32,537
Net income (loss)	(1,361)	7,621	37,731	15,548

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

We are a wholly owned subsidiary of Westar Energy and all evaluations of our controls and procedures were conducted in conjunction with those undertaken by Westar Energy. Under the supervision and with the participation of Westar Energy's management, and including our president and our principal financial and accounting officer, we have evaluated the effectiveness of the design and operation of our disclosure controls and procedures as defined in Rule 13a-15(e) 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 that evaluation, our president and our principal financial and accounting officer concluded that, as of December 31, 2003, 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 Securities and Exchange Commission rules and forms.

There were no changes in our internal control over financial reporting during our fourth quarter ended December 31, 2003, 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

Information required by Item 10 is omitted pursuant to General Instruction I(2)(c) to Form 10-K.

ITEM 11. EXECUTIVE COMPENSATION

Information required by Item 11 is omitted pursuant to General Instruction I(2)(c) to Form 10-K.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Information required by Item 12 is omitted pursuant to General Instruction I(2)(c) to Form 10-K.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Information required by Item 13 is omitted pursuant to General Instruction I(2)(c) to Form 10-K.

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)	$ 220,000	$ 455,000

(a) The 2002 audit fees include approximately $0.3 million for 2000 and 2001 re-audit fees.

Audit Committee Pre-Approval Policies and Procedures

Westar Energy's 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. Westar Energy's Audit Committee may consult with management in the decision-making process, but may not delegate this authority to management. Westar Energy's 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.

Westar Energy's 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

REPORTS ON FORM 8-K FILED DURING THE QUARTER ENDED DECEMBER 31, 2003:

None.

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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.

	Description	
3(a)	-Articles of Incorporation (Filed as Exhibit 3(a) to Form 10-K for the year ended December 31, 1992, File No. 1-7324)	I
3(b)	-Certificate of Merger of Kansas Gas and Electric Company into KCA Corporation (Filed as Exhibit 3(b) to Form 10-K for the year ended December 31, 1992, File No. 1-7324)	I
3(c)	-By-laws as amended (Filed as Exhibit 3(c) to Form 10-K for the year ended December 31, 1992, File No. 1-7324)	I
4(c)	-Mortgage and Deed of Trust, dated as of April 1, 1940 to Guaranty Trust Company of New York (now Morgan Guaranty Trust Company of New York) and Henry A. Theis (to whom W. A. Spooner is successor), Trustees, as supplemented by forty Supplemental Indentures, dated as of June 1, 1942, March 1, 1948, December 1, 1949, June 1, 1952, October 1, 1953, March 1, 1955, February 1, 1956, January 1, 1961, May 1, 1966, March 1, 1970, May 1, 1971, March 1, 1972, May 31, 1973, July 1, 1975, December 1, 1975, September 1, 1976, March 1, 1977, May 1, 1977, August 1, 1977, March 15, 1978, January 1, 1979, April 1, 1980, July 1, 1980, August 1, 1980, June 1, 1981, December 1, 1981, May 1, 1982, March 15, 1984, September 1, 1984 (Twenty-ninth and Thirtieth), February 1, 1985, April 15, 1986, June 1, 1991, March 31, 1992, December 17, 1992, August 24, 1993, January 15, 1994, March 1, 1994, April 15, 1994 and June 28, 2000, (Filed, respectively, as Exhibit A-1 to Form U-1, File No. 70-23; Exhibits 7(b) and 7(c), File No. 2-7405; Exhibit 7(d), File No. 2-8242; Exhibit 4(c), File No. 2-9626; Exhibit 4(c), File No. 2-10465; Exhibit 4(c), File No. 2-12228; Exhibit 4(c), File No. 2-15851; Exhibit 2(b)-1, File No. 2-24680; Exhibit 2(c), File No. 2-36170; Exhibits 2(c) and 2(d), File No. 2-39975; Exhibit 2(d), File No. 2-43053; Exhibit 4(c)2 to Form 10-K, for December 31, 1989, File No. 1-7324; Exhibit 2(c), File No. 2-53765; Exhibit 2(e), File No. 2-55488; Exhibit 2(c), File No. 2-57013; Exhibit 2(c), File No. 2-58180; Exhibit 4(c)3 to Form 10-K for December 31, 1989, File No. 1-7324; Exhibit 2(e), File No. 2-60089; Exhibit 2(c), File No. 2-60777; Exhibit 2(g), File No. 2-64521; Exhibit 2(h), File No. 2-66758; Exhibits 2(d) and 2(e), File No. 2-69620; Exhibits 4(d) and 4(e), File No. 2-75634; Exhibit 4(d), File No. 2-78944; Exhibit 4(d), File No. 2-87532; Exhibits 4(c)4, 4(c)5 and 4(c)6 to Form 10-K for December 31, 1989, File No. 1-7324; Exhibits 4(c)2 and 4(c)3 to Form 10-K for December 31, 1992, File No. 1-7324; Exhibit 4(b) to Form S-3, File No. 33-50075; Exhibits 4(c)2 and 4(c)3 to Form 10-K for December 31, 1993, File No. 1-7324; Exhibit 4(c)2 to Form 10-K for December 31, 1994, File No. 1-7324); 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 Form 10-Q for the quarter ended June 30, 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)	-LaCygne 2 Lease (filed as Exhibit 10(a) to Form 10-K for the year ended December 31, 1988, File No. 1-7324)	I
10(a)	-Amendment No. 3 to LaCygne 2 Lease Agreement dated as of September 29, 1992 (filed as Exhibit 10(b)1 to Form 10-K for the year ended December 31, 1992, File No. 1-7324)	I
10(b)	-Outside Directors' Deferred Compensation Plan (filed as Exhibit 10(c) to the Form 10-K for the year ended December 31, 1993, File No. 1-7324)*	I
12	-Computations of Ratio of Consolidated Earnings to Fixed Charges	
23	-Independent Auditors' Consent, Deloitte & Touche 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	

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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)	-Order on Rate Applications from The Corporation Commission of the State of Kansas in the Matter of the Application of Kansas Gas and Electric Company for the Approval to Make Certain Changes in its Charges for Electric Service (Filed as Exhibit 99.1 to Form 10-Q for the quarter ended June 30, 2001)	I
99(b)	-Letter to the SEC of assurances given by Arthur Andersen LLP regarding their audit of December 31, 2001 financial statements to the Company (filed as Exhibit 99(d) to Form 10-K for the year ended December 31, 2002)	I
99(c)	-Kansas Corporation Commission Order dated November 8, 2002 (filed as Exhibit 99.2 to Form 10-Q for the quarter ended June 30, 2002)	I
99(d)	-Kansas Corporation Commission Order dated December 23, 2002 (filed as Exhibit 99(f) to Form 10-K for the year ended December 31, 2002)	I
99(e)	-Debt Reduction Plan filed with the Kansas Corporation Commission on February 6, 2003 (filed as Exhibit 99(g) to Form 10-K for the year ended December 31, 2002)	I
99(f)	-Kansas Corporation Commission Order dated February 10, 2003 (filed as Exhibit 99(h) to Form 10-K for the year ended December 31, 2002)	I
99(g)	-Kansas Corporation Commission Order dated March 11, 2003 (filed as Exhibit 99(i) to Form 10-K for the year ended December 31, 2002)	I

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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.

KANSAS GAS AND ELECTRIC COMPANY

Date: March 15, 2004

By: /s/ Mark A. Ruelle

Mark A. Ruelle
Vice President and Treasurer

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/ William B. Moore (William B. Moore)	Chairman of the Board and President (Principal Executive Officer)	March 15, 2004
/s/ Mark A. Ruelle (Mark A. Ruelle)	Vice President and Treasurer (Principal Financial and Accounting Officer)	March 15, 2004
/s/ Douglas R. Sterbenz (Douglas R. Sterbenz)	Director	March 15, 2004
/s/ Caroline A. Williams (Caroline A. Williams)	Director	March 15, 2004

Kansas Gas and Electric Company
Computations of Ratio of Earnings to Fixed Charges
(Dollars in Thousands)

	Year Ended December 31,				
	2003	2002	2001	2000	1999
Earnings from continuing operations (a)	$ 66,627	$ 59,539	$ 50,199	$ 86,708	$ 84,261
Fixed Charges:					
Interest expense	55,467	47,844	49,610	49,606	49,518
Interest on corporate-owned life insurance borrowings	47,245	46,853	44,063	39,444	31,450
Interest applicable to rentals	19,563	20,636	22,688	22,903	23,968
Total Fixed Charges	122,275	115,333	116,361	111,953	104,936
Earnings (a)	$ 188,902	$ 174,872	$ 166,560	$ 198,661	$ 189,197
Ratio of Earnings to Fixed Charges	1.54	1.52	1.43	1.77	1.80

(a) Earnings are deemed to consist of earnings from continuing operations and fixed charges. 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 23

INDEPENDENT AUDITORS' CONSENT

We consent to the incorporation by reference in Registration Statement No. 33-50075 of Kansas Gas and Electric Company on Form S-3 of our report dated March 15, 2004, (which report expresses an unqualified opinion and includes an explanatory paragraph relating to the following changes in accounting principle: the Company changed its method of accounting for asset retirement obligations in 2003 and accounting for derivative contracts and hedging activities in 2001) appearing in this annual report on Form 10-K of Kansas Gas and Electric Company.

Deloitte & Touche LLP
Kansas City, Missouri
March 15, 2004

Exhibit 31(a)

KANSAS GAS AND ELECTRIC COMPANY
PRINCIPAL EXECUTIVE OFFICER
CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, William B. Moore, as chairman of the board and president of Kansas Gas and Electric Company, certify that:

1. I have reviewed this annual report on Form 10-K for the period ended December 31, 2003 of Kansas Gas and Electric Company;
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 15, 2004	By:	/S/ WILLIAM B. MOORE

William B. Moore,
Chairman of the Board and President
(Principal Executive Officer)

Exhibit 31(b)

KANSAS GAS AND ELECTRIC COMPANY
PRINCIPAL FINANCIAL AND ACCOUNTING OFFICER
CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Mark A. Ruelle, as vice president and treasurer of Kansas Gas and Electric Company, certify that:

1. I have reviewed this annual report on Form 10-K for the period ended December 31, 2003 of Kansas Gas and Electric Company;
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 15, 2004

By: /s/ Mark A. Ruelle

Mark A. Ruelle,
Vice President and Treasurer
(Principal Financial and 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 Kansas Gas and Electric Company (the Company) on Form 10-K for the year ended December 31, 2003 (the Report), which this certification accompanies, William B. Moore, in my capacity as Chairman of the Board and President (Principle Executive Officer) of the Company, and Mark A. Ruelle, in my capacity as Vice President and Treasurer (Principle Financial and Accounting 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 15, 2004

By: /s/ William B. Moore

William B. Moore,
Chairman of the Board and President
(Principal Executive Officer)

Date: March 15, 2004

By: /s/ Mark A. Ruelle

Mark A. Ruelle,
Vice President and Treasurer
(Principal Financial and Accounting Officer)