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, 2005

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)**

777 West Central, 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 is a well-known seasoned issuer (as defined in Rule 405 of the Act). Yes ☐ No ☒

Indicate by check mark whether the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

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 a large accelerated filer, an accelerated filer, or a non-accelerated filer (as defined in Rule 12b-2 of the Act). Check one:

Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☒

Indicate by check mark whether the registrant is a shell company (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 February 28, 2006)

Registrant meets the conditions of General Instruction I(1)(a) and (b) of 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,
- 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,
- the outcome of the Federal Energy Regulatory Commission transmission formula rate application filed on May 2, 2005,
- 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 outcome of the notice of violation received by Westar Energy, Inc. on January 22, 2004 from the Environmental Protection Agency and other environmental matters,
- political, legislative, judicial and regulatory developments,
- the impact of changes in interest rates,
- changes in, and the discount rate assumptions used for, Wolf Creek Nuclear Operating Corporation pension and other post-retirement benefit liability calculations, as well as actual and assumed investment returns on pension plan assets,
- the impact of changing interest rates and other assumptions regarding our Wolf Creek Generating Station decommissioning obligation,
- regulatory requirements for utility service reliability,
- homeland security considerations,
- coal, natural gas, oil and wholesale electricity prices,
- availability and timely provision of our coal supply, 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 this 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.

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PART I

ITEM 1. BUSINESS

GENERAL

Kansas Gas and Electric Company is a regulated electric utility incorporated in 1990 in 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. 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 305,000 customers in south-central and southeastern Kansas, including the city of Wichita. We own a 47% interest in the Wolf Creek Generating Station (Wolf Creek), a nuclear power plant located near Burlington, Kansas. Our corporate headquarters is located in Wichita, Kansas.

SIGNIFICANT BUSINESS DEVELOPMENTS DURING 2005

Overview

- Westar Energy and we filed applications with the Kansas Corporation Commission (KCC) on May 2, 2005 for an increase in our retail electric rates. Effective January 2006, the KCC authorized changes in our rates and approved various other changes in our rate structure. See “– Retail Rate Review” below for additional information.
- We incurred approximately $32.1 million in maintenance costs and capital expenditures to restore our electric distribution system as a result of a severe ice storm that occurred in January 2005. As allowed by the December 28, 2005 KCC Order, we will begin to recover these costs in rates in 2006.
- We repaid $65.0 million of our 6.5% first mortgage bonds that were due August 1, 2005, which reduced our interest expense. See Note 10 of the Notes to Consolidated Financial Statements, “Long-Term Debt,” for additional information.
- Coal delivery issues caused our coal inventory levels to decline significantly below desired levels, which required us to rely on more expensive sources of power to meet our customers’ energy needs.
- Wholesale sales volumes have declined and could continue to decline due to the cost and availability of fuel and growing demands of our retail customers.
- The cost of fuel and purchased power has increased significantly. Higher fuel and purchased power costs, unit outages, and operating constraints, such as our efforts to conserve coal, increased our total fuel and purchased power costs. However, we expect the effect of these increased costs to be mitigated with the February 2006 implementation of a retail energy cost adjustment (RECA) as discussed below.

Retail Rate Review

December 28, 2005 KCC Order

In accordance with a 2003 KCC order, Westar Energy and we filed applications with the KCC on May 2, 2005 to review our rates. We requested an increase in our retail electric rates and the adoption of other practices under the KCC's jurisdiction. The KCC ordered a decrease in our base rates of $3.1 million annually and requires that we credit to retail customers a rolling three-year average of the margins we realize from our market-based wholesale sales. Other significant changes approved by the KCC are the RECA, an environmental cost recovery rider (ECRR), the separation of transmission delivery charges, an increase in annual depreciation expense, an extended recovery period for costs being recovered for which no return is provided and the recovery of various costs that have been incurred and deferred as regulatory assets.

Retail Energy Cost Adjustment: The RECA allows us to recover the actual cost of fuel consumed in producing electricity and the cost of purchased power. The adjustment is based on the actual cost of fuel and purchased power less margins from market-based wholesale sales. We have contracts with certain large industrial customers, the terms of which do not provide for the separate billing of fuel costs. Fuel costs for these customers will continue to be recovered through the rates specified in each of these contracts. These customers represented approximately 16% of our total retail sales volumes for 2005.

Wholesale Sales Margins: The terms of the RECA require that we include, as a credit to recoverable fuel costs, an amount based on the average of the margins realized from market-based wholesale sales during the immediately prior three-year period. In any period we are unable to realize market-based wholesale sales margins at least equal to the amount of the credit, our financial results would be adversely affected. In the short-term, our generating capacity is fixed while the load requirements of our customers change constantly. When our generating capacity is not needed to serve our customers, we attempt to seek out wholesale sales of energy at prices in excess of the costs of production. We are likely to face the prospect of decreasing margins as the energy demands of our retail customers increase, which may result in crediting to retail customers an amount that would exceed the margins realized in the current period.

Environmental Cost Recovery Rider: The ECRR allows for the timely inclusion in rates, without requiring a full rate review, of the capital expenditures made to upgrade our equipment to meet stricter environmental standards required by the Clean Air Act. Prior to collection through rates, the KCC will review any environmental expenditures to be considered for recovery under the ECRR. Any increased operating and maintenance costs that result from updating or adding environmental equipment cannot be recovered through the ECRR. These costs would be addressed in future rate reviews.

Transmission Delivery Charge: The December 28, 2005 KCC Order allows us to separate our transmission costs from our base rates charged to retail customers. This allows us to implement a formula transmission rate that provides for annual adjustments to reflect changes in our transmission costs, which provides for adjustment on a more timely basis. These rates were proposed in an application filed with the Federal Energy Regulatory Commission (FERC) on May 2, 2005 and became effective on December 1, 2005, subject to refund upon review and approval by FERC.

Depreciation Rates: The December 28, 2005 KCC Order authorized an annual increase in the recovery of depreciation expense of approximately $13.4 million. The approved change in depreciation rates allows for the inclusion of net salvage costs, which include an estimate for the cost of dismantlement of plant facilities.

Disallowed Plant Costs: In 1985, the KCC disallowed certain costs associated with the original construction of Wolf Creek. In 1987, the KCC authorized us to recover these costs in rates over the original depreciable life of Wolf Creek, or through 2025, but disallowed any return on these costs. In its December 28, 2005 order, the KCC extended the recovery period to correspond to Wolf Creek's new estimated depreciable life. We recognized a loss of $10.4 million in the fourth quarter of 2005 as a result of the decrease in the present value of amounts to be received due to the extension of the recovery period.

Other Regulatory Assets: The December 28, 2005 KCC Order also approved for recovery approximately $37.1 million of deferred maintenance costs associated with restoring utility service to our customers stemming from damage to our lines and equipment in the ice storms that occurred in 2002 and 2005 and various other expenses that are relatively small in relation to the total regulatory asset balance.

OPERATIONS

General

We supply electric energy at retail to approximately 305,000 customers in south-central and southeastern Kansas. We also supply electric energy at wholesale to the electric distribution systems of 20 cities in Kansas and one electric cooperative that serves a rural area of Kansas. We have contracts for the sale, purchase or exchange of wholesale electricity with other utilities.

As discussed above, the December 28, 2005 KCC Order will allow us to recover the actual cost of fuel consumed in producing electricity and the cost of purchased power effective with the implementation of the new rates in February 2006. This applies to all fuel types we use and to our purchased power. The KCC will review our fuel and power purchasing practices on an annual basis to ensure that these expenses were incurred prudently. If it were determined that any portion of our fuel and purchased power expenses were incurred imprudently, these costs could be disallowed by the KCC.

Generation Capacity

We have 2,604 megawatts (MW) of generating capacity. 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	1,141.0	43.8
Nuclear	548.0	21.1
Natural gas or oil	912.0	35.0
Diesel fuel	3.0	0.1
Wind	0.2	—
Total	2,604.2	100.0

Our aggregate 2005 peak system net load of 2,183 MW occurred on July 25, 2005.

We have an agreement with Midwest Energy, Inc. to provide it with peaking capacity of 90 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 less 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 2005 actual fuel mix was 59% coal, 32% nuclear and 9% natural gas, oil and diesel fuel. We expect a similar fuel mix in 2006. Our fuel mix fluctuates with the operation of Wolf Creek, fluctuations in fuel costs, plant availability, customer demand and the cost and availability of power in the wholesale market.

Coal

Jeffrey Energy Center: The three coal-fired units at Jeffrey Energy Center have an aggregate capacity of 2,210 MW, of which we own a 20% share, or 442 MW. Westar Energy, the operator of Jeffrey Energy Center, and we have a long-term coal supply contract with Foundation Coal West to supply coal to Jeffrey Energy Center from surface mines located in the Powder River Basin (PRB) in Wyoming. The contract contains a schedule of minimum annual MMBtu delivery quantities. All of the coal used at Jeffrey Energy Center is purchased under this contract. The contract expires December 31, 2020. The contract provides for price escalation based on certain costs of production. The price for quantities purchased over the scheduled annual minimum is subject to renegotiation every five years to provide an adjusted price for the ensuing five years that reflects then current market prices. The next re-pricing is scheduled for 2008.

We transport coal from Wyoming under a long-term rail transportation contract with the Burlington Northern Santa Fe (BNSF) and Union Pacific railroads. The contract term continues through December 31, 2013. The contract price is subject to price escalation based on certain costs incurred by the rail carriers. We expect increases in the cost of transporting coal due to higher prices for the items subject to contractual escalation.

The average delivered cost of coal burned at Jeffrey Energy Center during 2005 was approximately $1.31 per MMBtu, or $21.99 per ton.

La Cygne Generating Station: The two coal-fired units at La Cygne Generating Station (La Cygne) have an aggregate generating capacity of 1,398 MW, of which we own or lease a 50% share, or 699 MW. La Cygne unit 1 uses a blended fuel mix containing approximately 85% PRB coal and 15% Kansas/Missouri coal. La Cygne unit 2 uses PRB coal. The operator of La Cygne, Kansas City Power & Light Company (KCPL), arranges coal purchases and transportation services for La Cygne. All of the La Cygne unit 1 and La Cygne unit 2 PRB coal is supplied through fixed price contracts through 2010 and is transported under KCPL's Omnibus Rail Transportation Agreement with the BNSF and Kansas City Southern Railroad through December 31, 2010. As the PRB coal contracts expire, we anticipate that KCPL will negotiate new supply contracts or purchase coal on the spot market. The La Cygne unit 1 Kansas/Missouri coal is purchased from time to time from local Kansas and Missouri producers.

During 2005, the average delivered cost of all coal burned at La Cygne unit 1 was approximately $1.05 per MMBtu, or $17.91 per ton. The average delivered cost of coal burned at La Cygne unit 2 was approximately $0.88 per MMBtu, or $14.76 per ton.

Natural Gas

We use natural gas either as a primary fuel or as a start-up and/or secondary fuel, depending on market prices, at our Gordon Evans, Murray Gill and Neosho Energy Centers. We purchase natural gas in the spot market, which supplies our facilities with natural gas to meet our operational needs. During 2005, we purchased 2.1 million MMBtu of natural gas on the spot market for a total cost of $16.6 million. Natural gas accounted for approximately 2% of our total MMBtu of fuel burned during 2005 and approximately 10% of our total fuel expense. From time to time, we may purchase derivative contracts or use other fuel types in an effort to mitigate the effect of high natural gas prices. 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

Once started with natural gas, most of the steam units at our Gordon Evans, Murray Gill and Neosho Energy Centers have the capability to burn oil or natural gas. We use oil as an alternate fuel when economical or when interruptions to natural gas supply make it necessary. During 2005 oil was more economical than natural gas, therefore, we used oil as the primary fuel in these generating facilities for most of 2005. During 2005, we burned 9.8 million MMBtu of oil at a total cost of $48.9 million. Oil accounted for approximately 7% of our total MMBtu of fuel burned during 2005 and approximately 28% of our total fuel expense. From time to time, we may purchase derivative contracts or use other fuel types in an effort to mitigate the effect of high oil prices. For additional information on our exposure to commodity price risks, see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

Oil is also used as a start-up fuel at some of our generating stations and in our diesel generator. We purchase oil in the spot market and under contract. We maintain quantities in inventory that we believe will allow us to facilitate economic dispatch of power, to satisfy emergency requirements and to protect against reduced availability of natural gas for limited periods.

Because oil does not burn as cleanly as natural gas, our ability to use as much oil in the future could be constrained by environmental regulations. See "–Environmental Matters" below for additional information.

Other Fuel Matters

The table below provides the weighted average cost of fuel that we have used, including transportation costs.

	2005	2004	2003
Per MMBtu:			
Nuclear	$ 0.42	$ 0.39	$ 0.39
Coal	1.10	0.99	0.96
Natural gas	7.83	5.45	4.51
Oil	5.01	3.79	3.20
Per MWh Generation:			
Nuclear	$ 4.34	$ 4.05	$ 4.08
Coal	11.94	10.87	10.45
Natural gas/oil	66.48	49.93	37.96
All generating stations	13.56	10.82	10.24

Purchased Power

At times, we purchase power to meet the energy needs of our customers. Factors that cause us to purchase power to serve our customers include outages at our generating plants, prices for wholesale energy, extreme weather conditions and other factors. If we were unable to generate an adequate supply of electricity to serve our customers, we would typically purchase power in the wholesale market. Transmission constraints may keep us from purchasing power in which case we would have to implement curtailment or interruption procedures as permitted by our tariffs and terms and conditions of service. Purchased power for the year ended December 31, 2005 comprised approximately 8% of our total operating expenses. The weighted average cost of purchased power was $53.97 per MWh in 2005, $56.41 per MWh in 2004 and $47.94 per MWh in 2003.

Energy Marketing Activities

We engage in both financial and physical trading to increase profits, manage our commodity price risk and enhance system reliability. We trade electricity, coal, natural gas and oil. We use a variety of financial instruments, including forward contracts, options and swaps, and we trade energy commodity contracts.

Nuclear Generation

General

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 owns a 47% interest in Wolf Creek and a 6% interest is owned by Kansas Electric Power Cooperative, Inc. (KEPCo). The co-owners pay operating costs equal to their percentage ownership in Wolf Creek.

Fuel Supply

We have 100% of the uranium and conversion services needed to operate Wolf Creek through September 2009 under contract. We also have 100% of the enrichment services required to operate Wolf Creek through March 2008 under contract. Letters of intent have been issued with suppliers for a majority of Wolf Creek's uranium, conversion and enrichment requirements extending through 2017. 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 we believe Wolf Creek is not substantially dependent on these agreements. However, contraction and consolidation among suppliers of these commodities and services, coupled with increasing worldwide demand and past inventory draw-downs, have introduced uncertainty as to the ability to replace, if necessary, some of these contracts in the event of a protracted supply disruption. We believe this potential problem is common in the nuclear industry. Accordingly, in the event the affected contracts were required to be replaced, we believe that the industry and government would arrive at a solution to reduce disruption of the nuclear industry's operations.

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 into a federal Nuclear Waste Fund administered by the DOE a quarterly fee for the future disposal of spent nuclear fuel. Our share of the fee was $3.8 million in 2005, $4.3 million in 2004 and $3.8 million in 2003 and is calculated as one-tenth of a cent for each kilowatt-hour of net nuclear generation produced. We include these costs in operating expenses.

In 2002, the Yucca Mountain site in Nevada was approved 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. Currently, the DOE has not defined a schedule for submitting a license application. The opening of the Yucca Mountain site has been delayed many times and could be delayed further due to litigation and other issues related to the site as a permanent repository for spent nuclear fuel. Wolf Creek has on-site temporary storage for spent nuclear fuel expected to be generated by Wolf Creek through the expiration of its operating license in 2025.

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. We believe that a temporary loss of low-level radioactive waste disposal capability would not affect Wolf Creek's continued operation.

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 (Central States Compact), and the Central States Compact Commission, which is responsible for causing a new disposal facility to be developed within one of the member states. The Central States Compact Commission selected Nebraska as the host state for the disposal facility.

In December 1998, the Nebraska agencies responsible for considering the developer's license application denied the application. Most of the utilities that had provided the project's pre-construction financing and the Central States Compact Commission filed a lawsuit in federal court contending Nebraska officials acted in bad faith while handling the license application. In September 2002, the court entered a judgment of $151.4 million, about one-third of which constitutes prejudgment interest, in favor of the Central States Compact Commission and against Nebraska, finding that Nebraska had acted in bad faith in handling the license application. Following unsuccessful appeals of the decision by Nebraska, in August 2004 Nebraska and the Central States Compact Commission settled the case. In August 2005, we received $9.2 million in proceeds from the Central States Compact as a result of the settlement.

Outages

Wolf Creek operates on an 18-month refueling and maintenance outage schedule. Wolf Creek was shut down for 41 days in 2005 for its fourteenth scheduled refueling and maintenance outage. During outages at the plant, we meet our electric demand primarily with our fossil-fueled generating units and by purchasing power, depending on availability and cost. As provided by the KCC, we amortize the incremental maintenance costs incurred for planned refueling outages evenly over the unit's 18 month operating cycle. Wolf Creek is scheduled to be taken off-line in the fall of 2006 for its fifteenth refueling and maintenance outage.

An extended or unscheduled shutdown of Wolf Creek could cause us to purchase replacement power, rely more heavily on our other generating units and reduce amounts of power available for us to sell at wholesale.

The NRC evaluates, monitors and rates various inspection findings and performance indicators for Wolf Creek based on their safety significance. Wolf Creek currently meets all NRC oversight objectives and receives the minimum regimen of NRC inspections. 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 expiration of the license of the related nuclear power plant. Wolf Creek files a nuclear decommissioning and dismantlement study with the KCC every three years.

The KCC reviews nuclear decommissioning plans in two phases. Phase one is the approval of the nuclear decommissioning study, the current-year funding and future 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 of its pro rata share of the plant.

Wolf Creek filed an updated nuclear decommissioning site study with the KCC. Based on the 2005 site study of decommissioning costs, including the costs of decontamination, dismantling and site restoration, our share of such costs are estimated to be $243.3 million. This amount compares to the 2002 site study estimate for decommissioning costs of $220.0 million. The site study cost estimate represents the estimate to decommission Wolf Creek as of the site study year. The actual nuclear decommissioning costs may vary from the estimates because of changes in technology and changes in costs for labor, materials and equipment.

Electric rates charged to customers provide for recovery of these nuclear decommissioning costs over the life of Wolf Creek, which, as determined by the KCC for purposes of the funding schedule, will be through 2045. The NRC requires that funds to meet its nuclear decommissioning funding assurance requirement be in our nuclear decommissioning fund by the time our license expires in 2025. We believe that the KCC approved funding level will be sufficient to meet the NRC minimum financial assurance requirement. However, our consolidated results of operations would be materially adversely affected if we are not allowed to recover the full amount of the funding requirement.

Nuclear decommissioning costs that are recovered in rates are deposited in an external trust fund. In 2005, we expensed approximately $3.9 million for nuclear decommissioning. We record our investment in the nuclear decommissioning fund at fair value. The fair value approximated $100.8 million at December 31, 2005 and $91.1 million at December 31, 2004.

Competition and Deregulation

Electric utilities have historically operated in a rate-regulated environment. FERC, the federal regulatory agency that has jurisdiction over our wholesale rates and transmission services, and other utilities have initiated steps 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 FERC to order electric utilities to allow third parties to use their transmission systems to transport electric power to wholesale customers. In 1992, we agreed to permit third parties access to our transmission system for wholesale transactions. FERC also requires us to provide transmission services to others under terms comparable to those we provide ourselves. In December 1999, FERC issued an order encouraging the formation of regional transmission organizations (RTO). 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.

Regional Transmission Organization

We are a member of the Southwest Power Pool (SPP). On October 1, 2004, FERC granted RTO status to the SPP. Westar Energy is now a member of the SPP RTO. Because we provide electric service together with the electric utility operations of Westar Energy, we are a member of the SPP through Westar Energy’s membership and do not have a separate KGE membership.

As a result of the SPP attaining RTO status, if approved by the KCC, we expect to transfer functional control of our transmission system to the SPP RTO under its membership agreement and applicable tariff. The SPP RTO will coordinate the operation of our transmission system within an interconnected transmission system across eight states. The SPP will collect revenues attributable to the use of each member’s transmission system. Members and transmission customers will be able to transmit power purchased and generated for sale or bought for resale in the wholesale market throughout the entire SPP system. We believe each transmission owner generally retains the transmission capacity needed to serve its 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 will have a material effect on our operations; however, we expect costs to increase due to the establishment of the RTO and associated markets. At this time, we are unable to quantify these costs because market implementation issues remain unresolved. We expect that we will recover these costs in rates we charge to our customers.

Real-Time Energy Imbalance Market

FERC requires RTOs to establish a real-time energy imbalance market. An energy imbalance exists when a transmission market participant's production and consumption of energy in real time does not net to zero. The intent of a real-time market system is to permit efficient balancing of production and consumption of energy and to manage congestion in real time. The SPP plans to implement a real-time energy imbalance market system on May 1, 2006. At this time, we are not able to identify the full impact on our results of operations.

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, the classification of accounts, the issuance of some securities and various other matters. We are also subject to the jurisdiction of 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.

Retail Rate Review

As discussed above in "– Significant Business Developments During 2005 –Retail Rate Review," our rates and cost of service were changed by the December 28, 2005 KCC Order.

FERC Proceedings

Request for Change in Transmission Rates: On May 2, 2005, Westar Energy and we filed applications with FERC that propose a formula transmission rate that provides for annual adjustments to reflect changes in Westar Energy's and our transmission costs. This is consistent with our proposals filed with the KCC on May 2, 2005 to separately charge retail customers for transmission service. These rates became effective on December 1, 2005, subject to refund. We can provide no assurance that FERC will ultimately approve our applications as filed.

Market-based Rates: On March 23, 2005, FERC instituted a proceeding concerning the reasonableness of Westar Energy's and our market-based rates in our electric control area and the electrical control areas of Midwest Energy, Inc. and Aquila, Inc.'s West Plains Energy division. Westar Energy and we have provided FERC with information it requested for its analysis. A FERC decision, anticipated in 2006, could affect how we price future wholesale power sales to wholesale customers in our control area and to Midwest Energy and West Plains Energy and wholesale customers in their control areas. We do not expect the outcome of this matter to significantly impact our consolidated results of operations.

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. We have incurred and will continue to incur capital and other expenditures to comply with environmental laws and regulations. As discussed above, the December 28, 2005 KCC Order established the ECRR, which will allow for the timely inclusion in rates capital expenditures that are directly tied to environmental improvements required by the Clean Air Act.

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 the costs relating to compliance with such laws and regulations, there can be no assurance that we will be able to recover all such increased costs from our customers or that our business, consolidated financial condition or results of operations will not be materially and adversely affected as a result of costs to comply with such existing and future laws and regulations.

Air Emissions

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

Certain Kansas Department of Health and Environment (KDHE) 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 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 operators of affected units that are anticipated to emit SO2 in excess of their allowances may purchase allowances from operators of affected units that are anticipated to emit SO2 in an amount less than their allowances. In 2005, we had enough emissions allowances to meet planned generation and we expect to have enough in 2006. The cost of emission allowances consumed is eligible to be recovered through the RECA. In future years, we expect to purchase SO2 allowances in order to meet the acid rain requirements of the Clean Air Act. We cannot estimate the cost at this time, but anticipate these costs may be material. The pricing of emissions allowances is unpredictable and may change over time.

On March 15, 2005, the EPA issued the Clean Air Mercury Rule to permanently cap and reduce mercury emissions from coal-fired power plants. The Clean Air Mercury Rule requires reductions of mercury in two phases starting in 2010. To comply with this rule, additional controls at our coal-fired units will be required as well as the installation of additional emission monitoring equipment. Several different environmental groups and states are challenging this rule in court, which could potentially delay the implementation of this rule. To date, no part of the Clean Air Mercury Rule has been stayed by any court although court cases remain open. Assuming this rule is not stayed, the first significant compliance date for us will be the installation, certification and operation of mercury continuous emissions monitoring systems on each coal-fired unit by January 1, 2009. Based on currently available information, we cannot estimate our costs to comply with the Clean Air Mercury Rule, but these costs could be material.

On March 10, 2005, in a separate but related action, the EPA issued the Clean Air Interstate Rule (CAIR) that addresses the impact of interstate transport of air pollutants on downwind states. CAIR requires reductions of SO2 and NOx in certain states in two separate phases, the first in 2010 and the second in 2015. Several states, including Kansas, are not included in the CAIR region, which reduces the impact this rule has on us.

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

- the EPA's national ambient air quality standards for particulate matter and ozone,
- the EPA's regional haze rules, designed to reduce SO_2, 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 CO_2, NOx, SO_2 and mercury, and the "Clear Skies" legislation proposed by the President, which would cap emissions of NOx, SO_2 and mercury.

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

Environmental Projects

KCPL began updating or installing additional equipment related to emissions controls at La Cygne unit 1 for which we incurred costs beginning in 2005. We will continue to incur costs through the completion of installation in 2009. We anticipate that our share of these costs will be approximately $105.0 million. Additionally, we have identified the potential for up to $225.0 million of expenditures at other power plants for other environmental projects during the next 8 years. This cost could increase depending on the resolution of the EPA New Source Review described below. In addition to the capital investment, were we to install such equipment, we anticipate that we would incur significant annual expense to operate and maintain the equipment and the operation of the equipment would reduce net production from our plants. As discussed above, the ECRR will allow for the timely inclusion in rates capital expenditures that are directly tied to environmental improvements required by the Clean Air Act. However, increased operating and maintenance costs can only be recovered through a change in our base rates following a rate review.

EPA New Source Review

Under Section 114(a) of the Clean Air Act (Section 114), the EPA is conducting investigations nationwide to determine whether modifications at coal-fired power plants are subject to New Source Review requirements or New Source Performance Standards. 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 in an attempt to reach a settlement. Westar Energy expects that any settlement with the EPA could require Westar Energy to update or install emissions controls at Jeffrey Energy Center over an agreed upon number of years. Additionally, Westar Energy might be required to update or install emissions controls at its other coal-fired plants, pay fines or penalties, or take other remedial action. Together, these costs could be material. The EPA informed Westar Energy that it has referred this matter to the Department of Justice (DOJ) for the DOJ to consider whether to pursue an enforcement action in federal district court. We believe that costs related to updating or installing emissions controls would qualify for recovery through the ECRR. If Westar Energy were to reach a settlement with the EPA, Westar Energy may be assessed a penalty. The penalty could be material and may not be recovered in rates. We anticipate that a portion of any of these potential costs would be allocated to us.

Manufactured Gas Sites

We have been associated with three former manufactured gas sites located in Kansas. We and the KDHE entered into a consent agreement in 1994 governing all future work at these sites.

SEASONALITY

As a summer peaking utility, our sales are seasonal. The third quarter typically accounts for our highest sales volumes. The volume of sales is affected by weather conditions, the economy of our service territory and the performance of our customers.

EMPLOYEES

Westar Energy provides all employees we utilize to perform our work and allocates the cost of such employees to us.

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 Internet 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 Securities and Exchange Commission. The information contained on Westar Energy's Internet website is not part of this document.

ITEM 1A. RISK FACTORS

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

Our Revenues Depend Upon Rates Determined by the KCC

The KCC regulates many aspects of our business and operations, including the retail rates that we charge customers for electric service. Retail rates are set by the KCC using a cost-of-service approach that takes into account historical operating expenses, fixed obligations and recovery of capital investments. Using this approach, the KCC sets rates at a level calculated to recover such costs and a permitted return on investment. Other parties to a rate review or the KCC staff may contend that our rates are excessive. Effective January 2006, the KCC authorized changes in our rates and approved various other changes in our rate structure. The KCC also approved the RECA, which is based on the actual cost of fuel and purchased power expense less margins earned on wholesale sales, and the ECRR, which is based on capital expenditures made to upgrade our equipment to meet stricter environmental standards required by the Clean Air Act.

Our Costs May Not be Fully Recovered in Retail Rates

Once established by the KCC, our rates generally remain fixed until changed in a subsequent rate review, except to the extent the KCC permits us to modify our tariffs using interim adjustment clauses, such as the RECA and the ECRR. We may elect to file a rate review to request a change in our rates or intervening parties may request that the KCC review our rates for possible adjustment, subject to any limitations that may have been ordered by the KCC.

Equipment Failures and Other External Factors Can Adversely Affect Our Results

The generation and transmission of electricity requires the use of expensive and complicated equipment. While we have a maintenance program in place, generating plants are subject to unplanned outages because of equipment failure. In these events, we must either produce replacement power from our less efficient units or purchase power from others at unpredictable and potentially higher cost in order to supply our customers and perform our contractual agreements. In addition, this can prevent us from having power to sell in the wholesale market. Coal deliveries from the PRB region of Wyoming, which is the primary source for our coal, have been slower than expected due primarily to problems with the rail tracks used to deliver our coal and operational problems at the mines where the coal is obtained. If rail delivery cycle times do not improve, we may be required to continue our coal conservation efforts and take other compensating measures. These measures include, but are not limited to, reducing coal consumption by revising normal dispatch of generation units, purchasing power or using more expensive power to serve customers and decreasing or, if necessary, eliminating market-based wholesale sales. In addition, decisions or mistakes by other utilities may adversely affect our ability to use transmission lines to deliver or import power, thus subjecting us to unexpected expenses or to the cost and uncertainty of public policy initiatives. These factors, as well as weather, interest rates, economic conditions, fuel availability, deliverability and prices, price volatility of fuel and other commodities and transportation availability and costs are largely beyond our control. Costs that are not recovered through the RECA could have a material adverse effect on our consolidated earnings, cash flows and financial position. We engage in energy marketing transactions to reduce risk from market fluctuations, enhance system reliability and increase profits. The events mentioned above could reduce our ability to participate in energy marketing opportunities, which could reduce our profits.

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

On January 22, 2004, the EPA notified Westar Energy that certain projects completed at Jeffrey Energy Center violated pre-construction permitting requirements under the Clean Air Act. This notification was delivered as part of an investigation by the EPA regarding maintenance activities that have been conducted since 1980 at Jeffrey Energy Center. The EPA has informed Westar Energy that it has referred this matter to the DOJ for it to consider whether to pursue an enforcement action in federal district court. The remedy for a violation could include fines and penalties and an order to install new emission control systems at Jeffrey Energy Center and at certain of Westar Energy's other coal-fired power plants, the associated cost of which could be material. We anticipate that a portion of any of these potential costs to Westar Energy would be allocated to us.

Our activities are subject to environmental regulation by federal, state, and local governmental authorities. These regulations generally involve the use of water, discharges of effluents into the water, emissions into the air, the handling, storage and use of hazardous substances, and waste handling, remediation and disposal, among others. Congress or the State of Kansas may enact legislation and the EPA or the State of Kansas may propose new regulations or change existing regulations that could require us to reduce certain emissions at our plants. Such action could require us to install costly equipment, increase our operating expense and reduce production from our plants.

The degree to which we will need to reduce emissions and the timing of when such emissions control equipment may be required is uncertain. Both the timing and the nature of required investments depend on specific outcomes that result from interpretation of regulations, new regulations, legislation, and the resolution of the EPA investigation described above. Although we expect to recover capital expenditures directly tied to environmental improvement through our rates, we can provide no assurance that we would be able to fully and timely recover all or any increased operating and maintenance costs relating to environmental compliance. Failure to recover these associated costs could have a material adverse effect on our consolidated financial condition or results of operations.

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

We currently apply the accounting principles of SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," to our regulated business. At December 31, 2005, we had recorded $243.9 million of regulatory assets, net of regulatory liabilities. At December 31, 2004, we had recorded $221.2 million of regulatory assets, net of regulatory liabilities. In the event that we determined that we could no longer apply the principles of SFAS No. 71, either as a result of the establishment of retail competition in our service territory or an expectation that permitted rates would not allow us to recover these costs, we would be required to record a charge against income in the amount of the remaining unamortized net regulatory assets.

We Face Financial Risks From Our Nuclear Facility

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

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

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ITEM 2. PROPERTIES

Name	Location	Unit No.		Year Installed	Principal Fuel	Unit Capacity (MW)
Gordon Evans Energy Center:	Colwich, Kansas					
Steam Turbines		1		1961	Gas—Oil	149.0
		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	148.0
Wind Turbines		1	(a)	1999	-	0.1
		2	(a)	1999	-	0.1
La Cygne Station (50%):	La Cygne, Kansas					
Steam Turbines		1	(a)	1973	Coal	362.0
		2	(b)	1977	Coal	337.0
Murray Gill Energy Center:	Wichita, Kansas					
Steam Turbines		1		1952	Gas	40.0
		2		1954	Gas—Oil	71.0
		3		1956	Gas—Oil	104.0
		4		1959	Gas—Oil	102.0
Neosho Energy Center:	Parsons, Kansas					
Steam Turbine		3		1954	Gas—Oil	63.0
Wolf Creek Generating Station (47%):	Burlington, Kansas					
Nuclear		1	(a)	1985	Uranium	548.0
Total						2,604.2

(a) We jointly own Jeffrey Energy Center (20%), La Cygne unit 1 generating unit (50%), and Wolf Creek Generating Station (47%). Westar Energy jointly owns 64% of Jeffrey Energy Center. Unit capacity amounts reflect our ownership only.

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

We own approximately 2,200 miles of transmission lines, approximately 9,900 miles of overhead distribution lines and approximately 2,100 miles of underground distribution lines.

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

ITEM 3. LEGAL PROCEEDINGS

Information on our legal proceedings is set forth in Notes 3, 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,				
	2005	2004	2003	2002	2001
			(In Thousands)		
Income Statement Data:					
Sales	$ 771,687	$ 714,939	$ 709,654	$ 695,524	$ 631,391
Income from operations before accounting change (a)	85,577	81,228	66,627	59,539	37,301

	As of December 31,				
	2005	2004	2003	2002	2001
			(In Thousands)		
Balance Sheet Data:					
Total assets	$2,971,579	$2,913,841	$2,911,217	$3,006,381	$2,933,044
Long-term debt (b)	487,427	552,419	549,604	684,486	684,360

(a) In 2001, we recognized a cumulative effect of accounting change of $12.9 million due to the adoption of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities."

(b) In 2003, we repaid $135.0 million of our 7.6% first mortgage bonds that were due December 15, 2003. In 2005, we repaid $65.0 million of our 6.5% first mortgage bonds that were due August 1, 2005.

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

INTRODUCTION

We are a regulated electric utility in Kansas and a wholly owned subsidiary of Westar Energy, Inc. 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 FERC.

In Management's Discussion and Analysis, we discuss our general financial condition, significant changes that occurred during 2005, and our operating results for the years ended December 31, 2005, 2004 and 2003. As you read Management's Discussion and Analysis, please refer to our consolidated financial statements and the accompanying notes, which contain our operating results.

SUMMARY OF SIGNIFICANT ITEMS

Overview

Several significant items have impacted us and our business operations since January 1, 2005.

- Westar Energy and we filed applications with the KCC on May 2, 2005 for an increase in our retail electric rates. Effective January 2006, the KCC authorized changes in our rates and various other changes in our rate structure. See "– Retail Rate Review" below for additional information.
- We incurred approximately $32.1 million in maintenance costs and capital expenditures to restore our electric distribution system as a result of a severe ice storm that occurred in January 2005. As allowed by the December 28, 2005 KCC Order, we will begin to recover these costs in rates in 2006.
- We repaid $65.0 million of our 6.5% first mortgage bonds that were due August 1, 2005, which reduced our interest expense. See Note 10 of the Notes to Consolidated Financial Statements, "Long-Term Debt," for additional information.
- Coal delivery issues caused our coal inventory levels to decline significantly below desired levels, which required us to rely on more expensive sources of power to meet our customers' energy needs.
- Wholesale sales volumes have declined and could continue to decline due to the cost and availability of fuel and growing demands of our retail customers.
- The cost of fuel and purchased power has increased significantly as discussed in more detail below in "– Increasing Cost of Fuel and Purchased Power."

Retail Rate Review

December 28, 2005 KCC Order

In accordance with a 2003 KCC order, Westar Energy and we filed applications with the KCC on May 2, 2005 to review our rates. We requested an increase in our retail electric rates and the adoption of other practices under the KCC's jurisdiction. The KCC ordered a decrease in our base rates of $3.1 million annually and requires that we credit to retail customers a rolling three-year average of the margins we realize from our market-based wholesale sales. Other significant changes approved by the KCC are the RECA, the ECRR, the separation of transmission delivery charges, an increase in annual depreciation expense, an extended recovery period for costs being recovered for which no return is provided and the recovery of various costs that have been incurred and deferred as regulatory assets.

Retail Energy Cost Adjustment: The RECA allows us to recover the actual cost of fuel consumed in producing electricity and the cost of purchased power. The adjustment is based on the actual cost of fuel and purchased power less margins from market-based wholesale sales. We have contracts with certain large industrial customers, the terms of which do not provide for the separate billing of fuel costs. Fuel costs for these customers will continue to be recovered through the rates specified in each of these contracts. These customers represented approximately 16% of our total retail sales volumes for 2005.

Wholesale Sales Margins: The terms of the RECA require that we include, as a credit to recoverable fuel costs, an amount based on the average of the margins realized from market-based wholesale sales during the immediately prior three-year period. In any period we are unable to realize market-based wholesale sales margins at least equal to the amount of the credit, our financial results would be adversely affected. In the short-term, our generating capacity is fixed while the load requirements of our customers change constantly. When our generating capacity is not needed to serve our customers, we attempt to seek out wholesale sales of energy at prices in excess of the costs of production. We are likely to face the prospect of decreasing margins as the energy demands of our retail customers increase, which may result in crediting to retail customers an amount that would exceed the margins realized in the current period.

Environmental Cost Recovery Rider: The ECRR allows for the timely inclusion in rates, without requiring a full rate review, of the capital expenditures made to upgrade our equipment to meet stricter environmental standards required by the Clean Air Act. Prior to collection through rates, the KCC will review any environmental expenditures to be considered for recovery under the ECRR. Any increased operating and maintenance costs that result from updating or adding environmental equipment cannot be recovered through the ECRR. These costs would be addressed in future rate reviews.

Transmission Delivery Charge: The December 28, 2005 KCC Order allows us to separate our transmission costs from our base rates charged to retail customers. This allows us to implement a formula transmission rate that provides for annual adjustments to reflect changes in our transmission costs, which provides for adjustment on a more timely basis. These rates were proposed in an application filed with FERC on May 2, 2005 and became effective on December 1, 2005, subject to refund upon review and approval by FERC.

Depreciation Rates: The December 28, 2005 KCC Order authorized an annual increase in the recovery of depreciation expense of approximately $13.4 million. The approved change in depreciation rates allows for the inclusion of net salvage costs, which include an estimate for the cost of dismantlement of plant facilities.

Disallowed Plant Costs: In 1985, the KCC disallowed certain costs associated with the original construction of Wolf Creek. In 1987, the KCC authorized us to recover these costs in rates over the original depreciable life of Wolf Creek, or through 2025, but disallowed any return on these costs. In its December 28, 2005 order, the KCC extended the recovery period to correspond to Wolf Creek's new estimated depreciable life. We recognized a loss of $10.4 million in the fourth quarter of 2005 as a result of the decrease in the present value of amounts to be received due to the extension of the recovery period.

Other Regulatory Assets: The December 28, 2005 KCC Order also approved for recovery approximately $37.1 million of deferred maintenance costs associated with restoring utility service to our customers stemming from damage to our lines and equipment in the ice storms that occurred in 2002 and 2005 and various other expenses that are relatively small in relation to the total regulatory asset balance.

Increasing Cost of Fuel and Purchased Power

The cost of power is impacted by, among other factors, customer demand, cost and availability of fuel and purchased power, price volatility, available generation capacity and operating constraints. Higher fuel and purchased power costs, unit outages, and operating constraints, such as our efforts to conserve coal, increased our total fuel and purchased power costs.

Cost of Fuel and Purchased Power: The cost of fossil fuel has increased since 2004. This is especially true for the cost of natural gas and oil. This higher cost of fuel affects not only the cost of fuel we burn, but also increases the market prices for both our wholesale sales and purchases of power. The cost and availability of fuel may cause us to use higher priced fuel types or to purchase power to meet our customers' energy needs. The effects of the fuel price increases are reflected in our operating results.

Unit Availability: Our operating results are significantly influenced by the availability of our generating units. If our more economical units are not available, we must rely on more expensive sources of power to meet our load requirements. During the year ended December 31, 2005, due to various planned and unplanned unit outages as well as some coal conservation efforts, we produced approximately 820,000 less megawatt hours (MWh) than during the same period of 2004. The primary outages during the year ended December 31, 2005 were the scheduled refueling and maintenance outage and an unplanned outage at Wolf Creek and planned and unplanned outages at Jeffrey Energy Center and La Cygne. The primary outages during the year ended December 31, 2004 were the planned and unplanned outages and reduced availability of Jeffrey Energy Center.

Operating Constraints: Our operating results are influenced by operating constraints on our generating units, such as coal conservation and maintenance outages. If our more economical units are constrained, we must rely on more expensive sources of power to meet our load requirements and/or forego opportunities in the wholesale power market. During the year ended December 31, 2005, coal conservation efforts, at times, reduced the energy generated at our more economical units and contributed to the decline in our market-based wholesale sales volumes. Coal conservation was required as a result of slower than expected coal deliveries, as discussed below.

Coal Inventory and Delivery: Coal deliveries from the PRB region of Wyoming were slower than expected due primarily to problems with the rail tracks used to deliver our coal and operational problems at the mines where the coal is obtained. Nearly all of the coal used in our coal-fired generating stations is from the PRB region of Wyoming.

During 2005, we implemented compensating measures based on delivery cycle times, our assumptions about future delivery cycle times, fuel usage and planned inventory levels. These measures included, but were not limited to, reducing coal consumption during off-peak periods by revising normal operational dispatch of our generating units, purchasing power or using more expensive power to serve customers, decreasing wholesale sales and purchasing and leasing additional rail cars. These actions helped to reduce the financial impact resulting from longer delivery cycle times. The effect of the reduction in sales due to slower coal deliveries has been partially offset by higher prices received for the power we have sold in the power markets.

CRITICAL ACCOUNTING ESTIMATES

Our discussion and analysis of financial condition and results of operations are based on our consolidated financial statements, which have been prepared in conformity with generally accepted accounting principles (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.

Regulatory Accounting

We currently apply accounting standards for our regulated utility operations that recognize the economic effects of rate regulation in accordance with SFAS No. 71. Accordingly, we 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.

The deferral of costs as regulatory assets is appropriate only when the future recovery of such costs is probable. In assessing probability, we consider such factors as specific orders from the KCC, regulatory precedent and the current regulatory environment. To the extent recovery of costs is no longer deemed probable, related regulatory assets would be required to be expensed in current period earnings.

Pension and Post-retirement Benefit Plans Actuarial Assumptions

The Wolf Creek pension benefit and post-retirement medical benefit obligations and related costs are calculated using actuarial concepts within the guidance provided by SFAS No. 87, “Employers’ Accounting for Pensions” and SFAS No. 106, “Employers’ Accounting for Postretirement Benefits Other Than Pensions.”

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

The following table shows the annual impact of a 0.5% change in our share of Wolf Creek's pension plan discount rate, salary scale and rate of return on plan assets.

Actuarial Assumption	Change in Assumption	Annual Change in Projected Benefit Obligation	Annual Change in Pension Liability/ Asset	Annual Increase in Projected Pension Expense
			(In Thousands)	
Discount rate	0.5% decrease	$ 6,356	$ 4,565	$ 907
	0.5% increase	(6,084)	(4,312)	(884)
Salary scale	0.5% decrease	(2,298)	665	(465)
	0.5% increase	2,338	(661)	475
Rate of return on plan assets	0.5% decrease	—	—	178
	0.5% increase	—	—	(178)

Our portion of the Wolf Creek pension expense was approximately $4.9 million in 2005, $4.0 million in 2004 and $3.7 million in 2003. Our portion of the Wolf Creek pension expense for 2006 is expected to approximate $6.1 million, which represents a $1.3 million increase over 2005. The increase is primarily due to the amortization of investment losses from prior years that are recognized on a rolling four-year average basis and changes in assumptions including a lower discount rate, lower return on assets, increase in salary scale and updated mortality tables.

The following table shows the annual impact of a 0.5% change in our share of the Wolf Creek post-retirement benefit plan discount rate.

Actuarial Assumption	Change in Assumption	Annual Increase in Projected Benefit Obligation	Annual Increase in Projected Post-retirement Expense
		(In Thousands)	
Discount rate	0.5% decrease	$ 365	$ 33
	0.5% increase	(352)	(32)

Revenue Recognition — Energy Sales

We recognize revenues from retail energy sales upon delivery to the customer and include an estimate for energy delivered but unbilled. Our estimate of revenue attributable to this unbilled portion is based on the total energy available for sale measured against billed sales. At December 31, 2005, we had estimated unbilled revenue of $21.2 million.

We are allocated a share of revenues from energy marketing derivative contracts 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. We account for energy marketing derivative contracts under the mark-to-market method of accounting. Under this method, we recognize changes in the portfolio value as gains or losses in the period of change. With the exception of fuel contracts, we include the net mark-to-market change in sales on our consolidated statements of income. We record the resulting unrealized gains and losses as energy marketing long-term or short-term assets and liabilities on our consolidated balance sheets as appropriate. We use quoted market prices to value our energy marketing derivative contracts when such data are available. When market prices are not readily available or determinable, we use alternative approaches, such as model pricing. Prices used to value these transactions reflect our best estimate of fair values of our trading positions. Results actually achieved from these activities could vary materially from intended results and could affect our consolidated financial results.

The tables below show fair value of energy marketing contracts outstanding for the year ended December 31, 2005, their sources and maturity periods.

	Fair Value of Contracts (In Thousands)
Net fair value of contracts outstanding at December 31, 2004	$ 1,625
Contracts outstanding at the beginning of the period that were realized or otherwise settled during the period	(1,523)
Changes in fair value of contracts outstanding at the beginning and end of the period	(688)
Fair value of new contracts entered into during the period	103
Fair value of contracts outstanding at December 31, 2005	$ (483)

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
		(In Thousands)	
Prices actively quoted (futures)	$ (60)	$ (60)	$ —
Prices provided by other external sources (swaps and forwards)	(96)	86	(182)
Prices based on the Black Option Pricing model (options and other) (a)	(327)	(327)	—
Total fair value of contracts outstanding	$ (483)	$ (301)	$ (182)

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

Income Taxes

We use the asset and liability method of accounting for income taxes as required by SFAS No. 109, “Accounting for Income Taxes.” Under the asset and liability method, we recognize deferred tax assets and liabilities for the future tax consequences attributable to temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. We recognize the future tax benefits to the extent that realization of such benefits is more likely than not. We amortize deferred investment tax credits over the lives of the related properties.

Asset Retirement Obligations

We calculate our asset retirement obligations and related costs using the guidance provided by SFAS No. 143, "Accounting for Asset Retirement Obligations" and the Financial Accounting Standards Board's (FASB) Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations" (FIN 47).

We estimate our asset retirement obligations based on the fair value of the asset retirement obligation we incurred at the time the related long-lived asset was either acquired, placed in service or when regulations establishing the obligation become effective.

In determining our asset retirement obligations, we make assumptions regarding probable disposal costs. A change in these assumptions could have a significant impact on our asset retirement obligations reflected on our consolidated balance sheets.

OPERATING RESULTS

We evaluate operating results based on income from operations. We have various classifications of sales, defined as follows:

Retail: Sales of energy made to residential, commercial and industrial customers.

Other retail: Sales of energy for lighting public streets and highways, net of revenues reserved for rebates.

Tariff-based wholesale: Sales of energy to electric cooperatives, municipalities and other electric utilities, the rate for which is generally based on cost as prescribed by FERC tariffs. Also includes changes in valuations of contracts that have yet to settle.

Market-based wholesale: Sales of energy to other wholesale customers, the rate for which is based on prevailing market prices as allowed by our FERC approved market-based tariff. Also includes changes in valuations of contracts that have yet to settle.

Energy marketing: Includes: (1) financially settled products and physical transactions sourced outside our control area; and (2) changes in valuations for contracts that have yet to settle that may not be recorded in tariff- or market-based wholesale revenues.

Transmission: Reflects transmission revenues received, including those based on a tariff with the SPP.

Other: Miscellaneous electric revenues including ancillary service revenues and rent from electric property leased to others.

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, among other factors, demand, cost of fuel and purchased power, price volatility, available generation capacity and transmission availability. Changing weather affects the amount of electricity our customers use. Very hot summers and very cold winters prompt more demand, especially among our residential customers. Mild weather reduces demand.

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2005 Compared to 2004

Below we discuss our operating results for the year ended December 31, 2005 as compared to the results for the year ended December 31, 2004. Changes in results of operations are as follows.

	Year Ended December 31, 2005	2004	Change	% Change
	(In Thousands)			
SALES:				
Residential	$234,718	$218,362	$ 16,356	7.5
Commercial	184,710	174,543	10,167	5.8
Industrial	156,238	154,593	1,645	1.1
Other retail	112	978	(866)	(88.5)
Total Retail Sales	575,778	548,476	27,302	5.0
Tariff-based wholesale	33,738	20,058	13,680	68.2
Market-based wholesale	110,556	95,790	14,766	15.4
Energy marketing	3,700	891	2,809	315.3
Transmission (a)	36,230	36,771	(541)	(1.5)
Other	11,685	12,953	(1,268)	(9.8)
Total Sales	771,687	714,939	56,748	7.9
OPERATING EXPENSES:				
Fuel used for generation (b)	187,699	151,711	35,988	23.7
Purchased power	54,263	29,328	24,935	85.0
Operating and maintenance	242,418	229,587	12,831	5.6
Depreciation and amortization	80,482	91,835	(11,353)	(12.4)
Selling, general and administrative	82,939	75,105	7,834	10.4
Total Operating Expenses	647,801	577,566	70,235	12.2
INCOME FROM OPERATIONS	$123,886	$137,373	$(13,487)	(9.8)

(a) **Transmission:** Includes an SPP network transmission tariff. In 2005, our SPP network transmission costs were approximately $33.1 million. This amount, less approximately $2.7 million that was retained by the SPP as administration cost, was returned to us as revenue. In 2004, our SPP network transmission costs were approximately $33.3 million with an administration cost of $2.2 million retained by the SPP.

(b) **Fuel used for generation:** Includes cost of fuel burned and net dispatch costs allocated to us by Westar Energy.

The following table reflects changes in electric sales volumes, as measured by thousands of MWh of electricity, for the years ended December 31, 2005 and 2004. No sales volumes are shown for energy marketing, transmission or other. Energy marketing activities are unrelated to electricity we generate.

	2005	2004	Change	% Change
	(Thousands of MWh)			
Residential	3,033	2,816	217	7.7
Commercial	2,935	2,768	167	6.0
Industrial	3,617	3,511	106	3.0
Other retail	44	44	—	—
Total Retail	9,629	9,139	490	5.4
Tariff-based wholesale	679	417	262	62.8
Market-based wholesale	2,188	2,804	(616)	(22.0)
Total	12,496	12,360	136	1.1

Residential and commercial sales and sales volumes increased due primarily to warmer weather during 2005 than experienced in 2004. When measured by cooling degree days, the weather during 2005 was 19% warmer than during 2004 and 8% above the 20-year average. We measure cooling degree days experienced in the Wichita metropolitan area, which we believe to be generally reflective of conditions in our service territory.

The warmer weather also contributed to the increased tariff-based wholesale sales and sales volumes. Additionally, about $2.0 million, or 15%, of the increase in the tariff-based wholesale sales was due to the Wolf Creek outages. We sold more tariff-based wholesale power to KEPCo in accordance with a contract to supply replacement power when Wolf Creek is not available. We had more energy available from Jeffrey Energy Center, which also contributed to the increased tariff-based wholesale sales.

Higher prevailing fuel prices have caused wholesale market prices to increase, which was the primary reason our market-based wholesale sales increased. Market-based wholesale sales volumes declined because less energy was available for sale due to the increase in retail and tariff-based wholesale sales.

Fuel expense increased due primarily to using more expensive sources of generation because of the lower unit availability of our more economical generating units. Cost of fuel used for generation increased $26.5 million, or approximately 18%, even though we used approximately 7% less MMBtu (million British thermal unit) of fuel. The average fuel price for 2005 was approximately 26% higher than in 2004. Westar Energy operates our combined system based on what is most economical for the combined companies at any given time. When less expensive power is available from Westar Energy’s central and northeastern Kansas control area, the dispatch costs for the power that we are allocated may be higher than when power is available in our control area. This occurred in 2005 due primarily to outages at Jeffrey Energy Center, La Cygne and Wolf Creek in 2005 that caused us to rely on other sources of power. Dispatch costs allocated to us increased approximately $9.5 million.

Purchased power expense increased due primarily to nearly doubling the quantity purchased. This was due to the various outages or reduced operating capability at some of our generating units and the availability of economically priced power. At times, it was more economical to purchase power than to operate our available generating units.

Operating and maintenance expense increased due to a number of factors, the largest of which was a $10.4 million write-off of disallowed plant costs as discussed above in “– Summary of Significant Items – Retail Rate Review – December 28, 2005 KCC Order – Disallowed Plant Costs.”

In addition, costs of operating and maintaining our distribution system increased $3.0 million due primarily to higher labor costs and additional maintenance projects. Also causing the operating and maintenance expense to increase was a $3.5 million charge to write off plant operating system development costs at Wolf Creek due to non-performance of the vendor developing the system. These higher expenses were partially offset by a $5.4 million decline in expense related to changes in the La Cygne unit 2 operating lease as discussed in Note 17 of the Notes to Consolidated Financial Statements, “Operating Leases.”

Depreciation expense decreased primarily because we established a regulatory asset for the depreciation differences between those used for financial statement purposes and regulatory rate making purposes from August 2001 to March 2002 pursuant to the December 28, 2005 KCC Order, which allowed us to record a reduction in depreciation expense of $12.0 million.

Selling, general and administrative expenses increased due primarily to employee pension and benefit costs allocated to us.

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2004 Compared to 2003

Below we discuss our operating results for the year ended December 31, 2004 as compared to the results for the year ended December 31, 2003. Changes in results of operations are as follows.

	Year Ended December 31, 2004	2003	Change	% Change
		(In Thousands)		
SALES:				
Residential	$218,362	$220,929	$ (2,567)	(1.2)
Commercial	174,543	169,670	4,873	2.9
Industrial	154,593	153,463	1,130	0.7
Other retail	978	3,253	(2,275)	(69.9)
Total Retail Sales	548,476	547,315	1,161	0.2
Tariff-based wholesale	20,058	20,693	(635)	(3.1)
Market-based wholesale	95,790	86,169	9,621	11.2
Energy marketing	891	6,093	(5,202)	(85.4)
Transmission (a)	36,771	36,217	554	1.5
Other	12,953	13,167	(214)	(1.6)
Total Sales	714,939	709,654	5,285	0.7
OPERATING EXPENSES:				
Fuel used for generation (b)	151,711	155,390	(3,679)	(2.4)
Purchased power	29,328	22,585	6,743	29.9
Operating and maintenance	229,587	221,667	7,920	3.6
Depreciation and amortization	91,835	90,604	1,231	1.4
Selling, general and administrative	75,105	70,737	4,368	6.2
Total Operating Expenses	577,566	560,983	16,583	3.0
INCOME FROM OPERATIONS	$137,373	$148,671	$(11,298)	(7.6)

(a) **Transmission:** Includes an SPP network transmission tariff. In 2004, our SPP network transmission costs were approximately $33.3 million. This amount, less $2.2 million that was retained by the SPP as administration cost, was returned to us as revenue. In 2003, our SPP network transmission costs were approximately $32.7 million with an administration cost of $2.9 million retained by the SPP.

(b) **Fuel used for generation:** Includes cost of fuel burned, changes in fair value of fuel contracts and net dispatch costs, which represent energy transactions allocated to us by Westar Energy.

The following table reflects changes in electric sales volumes, as measured by thousands of MWh of electricity, for the years ended December 31, 2004 and 2003. No sales volumes are shown for energy marketing, transmission or other. Energy marketing activities are unrelated to electricity we generate.

	2004	2003	Change	% Change
	(Thousands of MWh)			
Residential	2,816	2,842	(26)	(0.9)
Commercial	2,768	2,685	83	3.1
Industrial	3,511	3,459	52	1.5
Other retail	44	44	—	—
Total Retail	9,139	9,030	109	1.2
Tariff-based wholesale	417	488	(71)	(14.5)
Market-based wholesale	2,804	2,668	136	5.1
Total	12,360	12,186	174	1.4

Our residential and tariff-based wholesale customers used less energy and our sales volumes decreased because of cooler weather during the summer. When measured by cooling degree days, the weather during 2004 was 4% cooler than during 2003 and 9% below the 20-year average. The accrual for rebates to be paid to customers in 2005 and 2006 pursuant to the July 25, 2003 KCC Order also reduced revenues from retail sales. During 2004, we accrued $4.0 million as compared to $1.7 million accrued during 2003.

Market-based wholesale sales increased due primarily to increased sales volumes and an approximate 6% increase in the average price per MWh. As a result of milder weather, we had additional energy production available for sale at certain times during the year that was not needed to serve our retail and tariff-based wholesale customers. Increased sales volumes accounted for approximately $4.6 million of the increased market-based wholesale sales and higher average market prices accounted for approximately $5.0 million of the increase. Energy marketing sales declined because we had less favorable changes in 2004 as compared to the favorable changes in 2003 in the settlement and the fair value of positions receiving mark-to-market accounting treatment.

Fuel used for generation decreased in 2004 due primarily to a reduction in fuel costs that were allocated to us by Westar Energy. In 2004, Wolf Creek did not have a scheduled refueling outage.

Purchased power expense increased due primarily to a 10% increase in volumes purchased during 2004 as compared to 2003. This was due to the unplanned outages or reduced operating capability of our units at certain times and the availability of economically priced power due to cooler weather in our region. At times, it was more economical to purchase power than to operate our available generating units.

Selling, general and administrative expenses increased in 2004, which reflects an increase in labor overheads allocated to us by Westar Energy. Operating and maintenance expenses increased due primarily to increased expenses associated with maintenance at Jeffrey Energy Center, increased planned and unplanned unit maintenance at various other generating units, increased maintenance of the distribution system, increased operating costs at Wolf Creek and an increase in transmission costs. During 2004, increased maintenance of our generating units accounted for 14% of the increase in operating and maintenance expenses. The increase in distribution expenses accounted for 35% of the increase in operating and maintenance expenses. Distribution expenses increased due to increased staffing levels and higher costs associated with the termination of portions of the ONEOK, Inc. shared services agreement as discussed in Note 18 of the Notes to Consolidated Financial Statements, “Related Party Transactions.” Wolf Creek operating costs increased 22% because it operated more during 2004 because Wolf Creek did not have a scheduled refueling outage as it did in 2003. An increase in transportation costs accounted for 9% of the increase in operating and maintenance expenses.

FINANCIAL CONDITION

Below we discuss significant balance sheet changes at December 31, 2005 compared to December 31, 2004.

Accounts receivable increased $32.1 million due primarily to an increase in sales in late 2005 compared to late 2004. In addition, the amounts of receivables sold under our accounts receivable sales program as discussed in Note 4 of the Notes to Consolidated Financial Statements, “Accounts Receivable Sales Program,” decreased $15.0 million, to $65.0 million at December 31, 2005, from $80.0 million at December 31, 2004.

Regulatory assets, net of regulatory liabilities, increased to $243.9 million at December 31, 2005, from $221.2 million at December 31, 2004, due primarily to changes that resulted from the December 28, 2005 KCC Order. Total regulatory assets increased $32.0 million due primarily to maintenance costs recorded in association with an ice storm that occurred in January 2005, an increase in depreciation due to changes authorized by the December 28, 2005 KCC Order and the recording of conditional asset retirement obligations. For additional information on our regulatory assets and liabilities, see Note 2 of the Notes to Consolidated Financial Statements, “Summary of Significant Accounting Policies – Regulatory Accounting.”

Current maturities of long-term debt increased $35.0 million. The balance at December 31, 2005 consisted of the $100.0 million outstanding aggregate principal amount of our 6.2% first mortgage bonds that are due in January 2006. The balance at December 31, 2004 consisted of $65.0 million outstanding aggregate principal amount of our 6.5% first mortgage bonds that were due in August 2005.

Long-term debt, net of current maturities, decreased approximately $100.0 million because of the $100.0 million outstanding aggregate principal amount of our 6.2% first mortgage bonds that are due in January 2006 and were consequently reclassified as a current liability as discussed above.

Our long-term deferred income tax liability decreased $19.6 million due to adjustments to plant-related deferred income taxes, primarily amounts due from customers for future income taxes.

Asset retirement obligations increased $36.3 million. In 2005, we determined that we have conditional asset retirement obligations that are within the scope of FIN 47 and, as a result, increased our asset retirement obligations by $14.7 million. Also during 2005, we updated our nuclear decommissioning and dismantlement study. Based upon the results of this study, we revised our estimate of our Wolf Creek asset retirement obligation and increased our liability by $14.6 million. In addition, we recorded $7.0 million in accretion expense on our asset retirement obligation related to the decommissioning of Wolf Creek. These items are discussed in greater detail in Note 14 of the Notes to Consolidated Financial Statements, “Asset Retirement Obligations.”

LIQUIDITY AND CAPITAL RESOURCES

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

We expect our internally generated cash, advances from Westar Energy, availability of cash through Westar Energy’s credit facilities and access to capital markets 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.

Cash Flows from Operating Activities

Cash flows from operating activities decreased $8.1 million to $129.1 million in 2005 from $137.2 million in 2004. During 2005, we used approximately $27.9 million for system restoration costs related to the ice storm that affected our service territory in January 2005, and approximately $14.2 million for the Wolf Creek refueling outage.

Cash Flows used in Investing Activities

In general, cash used for investing purposes relates to the growth and improvement of our utility operations. Our business is capital intensive and requires significant investment in plant on an annual basis. We spent $87.2 million in 2005, $99.0 million in 2004 and $89.2 million in 2003 on net additions to property, plant and equipment.

Cash Flows used in Financing Activities

Net cash used in financing activities totaled $38.8 million for the year ended December 31, 2005 as compared to $25.5 million for the year ended December 31, 2004. Net cash used in financing activities totaled $30.9 million for the year ended December 31, 2003. In 2005, cash was used for the retirement of long-term debt and to pay $20.0 million in dividends to Westar Energy. In 2004, cash was used for the retirement of long-term debt and to pay $75.0 million in dividends to Westar Energy. In 2003, cash was used to retire long-term debt and to pay $100.0 million in dividends to Westar Energy.

Future Cash Requirements

Our business requires significant capital investments. Through 2008, we expect we will need cash mostly for utility construction programs designed to improve facilities providing electric service, for future peaking capacity needs and to comply with environmental regulations. We expect to meet these cash needs with internally generated funds, borrowings from Westar Energy and through the issuance of securities in the capital markets.

If Westar Energy is required to update emissions controls or take other remedial action 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 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. The following table does not include any amounts related to these possible expenditures. We expect that costs related to updating or installing emissions controls will be material. As discussed above, the ECRR will allow for timely inclusion in rates of the costs of capital expenditures directly tied to environmental improvements required by the Clean Air Act. We believe that other costs incurred would qualify for recovery through rates.

Capital expenditures for 2005 and anticipated capital expenditures for 2006 through 2008, including costs of removal, are shown in the following table.

	Actual 2005	2006	2007	2008
		(In Thousands)		
Generation:				
Replacements and other	$23,300	$ 32,100	$ 28,400	$ 32,300
Additional capacity	7,315	—	—	500
Environmental	2,261	24,000	58,000	56,700
Nuclear fuel	5,046	21,200	26,000	2,100
Transmission	5,418	9,100	10,700	9,800
Distribution:				
Replacements and other	18,016	13,300	12,300	12,300
New customers	20,352	24,600	25,100	25,700
Other	5,464	4,300	4,500	5,000
Total capital expenditures	$87,172	$128,600	$165,000	$144,400

We prepare these estimates for planning purposes and revise our estimates 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.

Maturities of long-term debt at December 31, 2005 are as follows.

Year	Principal Amount (In Thousands)
2006	$ 100,000
Thereafter	387,427
Total long-term debt maturities	$ 487,427

Debt Financings

On January 17, 2006, we repaid the outstanding $100.0 million aggregate principal amount of our 6.2% first mortgage bonds with cash on hand and borrowings under the Westar Energy revolving credit facility. On August 1, 2005, we repaid the outstanding $65.0 million aggregate principal amount of our 6.5% first mortgage bonds with cash on hand and borrowings under the Westar Energy revolving credit facility.

On May 6, 2005, Westar Energy amended its revolving credit facility dated March 12, 2004 to extend the term and reduce borrowing costs. The amended revolving credit facility matures on May 6, 2010. The facility is used as a source of short-term liquidity. It allows Westar Energy to borrow up to an aggregate amount of $350.0 million, including letters of credit up to a maximum aggregate amount of $100.0 million. So long as there is no default or event of default under the revolving credit facility, Westar Energy may elect, subject to lender participation, to increase the aggregate amount of borrowings under this facility to $500.0 million. All borrowings under the revolving credit facility are secured by our first mortgage bonds.

A default by Westar Energy or us under other indebtedness totaling more than $25.0 million is a default under Westar Energy's revolving credit facility. Westar Energy is required to maintain a consolidated indebtedness to consolidated capitalization ratio not greater than 65% at all times. Available liquidity under the revolving credit facility is not impacted by a decline in Westar Energy's credit ratings. Also, the revolving credit facility does not contain a material adverse effect clause requiring Westar Energy to represent, prior to each borrowing, that no event resulting in a material adverse effect has occurred.

On June 10, 2004, we refinanced $327.5 million of pollution control bonds. The original issue had an interest rate of 7% and was due in 2031. This issue was replaced with pollution control bonds at interest rates of 5.3% on $127.5 million that matures in 2031, 2.65% on $100.0 million that matures in 2031, and a variable rate on $100.0 million that matures in 2031.

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 calculates these ratios in accordance with its credit agreements. These ratios are used solely to determine compliance with its various debt covenants. Westar Energy was in compliance with these covenants at December 31, 2005.

Our mortgage contains provisions restricting the amount of first mortgage bonds that we could issue. Therefore, we must ensure that we will be able to comply with such restrictions prior to the issuance of additional first mortgage bonds or other secured indebtedness.

Our mortgage prohibits additional first mortgage bonds from being issued, except in connection with certain refundings, unless our net earnings before income taxes and before provision for retirement and depreciation of property for a period of 12 consecutive months within 15 months preceding the issuance are not less than either two and one-half times the annual interest charges on, or 10% of the principal amount of, all 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. At December 31, 2005, based on an assumed interest rate of 6%, approximately $607.3 million principal amount of additional first mortgage bonds could be issued under the most restrictive provisions in the mortgage.

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.

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On January 30, 2006, Moody's lowered Westar Energy's speculative grade liquidity rating to SGL-2 (good) from SGL-1 (very good). On February 23, 2005, Moody's upgraded its ratings for our debt. Our secured debt ratings were upgraded to Baa3 from Ba1. On December 22, 2004, Fitch raised its outlook for our ratings to positive from stable and affirmed its ratings as shown in the table below. On July 22, 2004, S&P improved its ratings on our first mortgage bonds to BBB from BB+.

As of March 1, 2006, ratings with these agencies are as shown in the table below.

	Westar Energy Mortgage Bond Rating	Westar Energy Unsecured Debt	KGE Mortgage Bond Rating
S&P	BBB-	BB-	BBB
Moody's	Baa3	Ba1	Baa3
Fitch	BBB-	BB+	BBB-

In general, less favorable credit ratings make debt financing more costly and more difficult to obtain on terms that are economically favorable to us. Westar Energy and we have credit rating conditions under our revolving credit agreement and in the agreements governing the sale of our accounts receivable discussed in Note 4 of the Notes to Consolidated Financial Statements, "Accounts Receivable Sales Program," that affect the cost of borrowing but do not trigger a default. We may enter into new credit agreements that contain credit conditions, which could affect our liquidity and/or our borrowing costs.

Capital Structure

Our consolidated capital structure at December 31, 2005 and 2004 was as follows.

	2005	2004
Shareholder's equity	70%	66%
Debt	30%	34%
Total	100%	100%

OFF-BALANCE SHEET ARRANGEMENTS

At December 31, 2005, we did not have any off-balance sheet financing arrangements, other than our accounts receivable sales program and operating leases entered into in the ordinary course of business.

Accounts Receivable Sales Program

Under a revolving accounts receivable sales program, we and Westar Energy can currently sell up to $125.0 million of our accounts receivable. For additional detail, see Note 4 of the Notes to Consolidated Financial Statements, "Accounts Receivable Sales Program."

CONTRACTUAL OBLIGATIONS

In the course of our business activities, we enter into a variety of obligations and commercial commitments. Some of these result in direct obligations reflected on our consolidated balance sheets while others are commitments, some firm and some based on uncertainties, not reflected in our underlying consolidated financial statements. The obligations listed below do not include amounts for on-going needs for which no contractual obligations existed at December 31, 2005. We may from time to time enter into new contracts to replace contracts that expire.

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The following table summarizes the projected future cash payments for our contractual obligations existing at December 31, 2005.

	Total	2006 (c)	2007 - 2008	2009 - 2010	Thereafter
			(In Thousands)		
Long-term debt (a)	$ 487,427	$ 100,000	$ —	$ —	$ 387,427
Interest on long-term debt (b)	403,805	18,224	30,248	30,248	325,085
Adjusted long-term debt	891,232	118,224	30,248	30,248	712,512
Wolf Creek pension benefit funding obligations (c)	6,000	6,000	—	—	—
Operating leases (d)	537,810	36,731	60,807	70,170	370,102
Fossil fuel (e)	424,553	60,187	129,434	83,128	151,804
Nuclear fuel (f)	147,453	24,902	19,595	15,398	87,558
Unconditional purchase obligations	23,529	19,000	4,525	—	4
Miscellaneous obligations (g)	4,994	4,994	—	—	—
Total contractual obligations, including adjusted long-term debt	$ 2,035,571	$ 270,038	$ 244,609	$ 198,944	$ 1,321,980

(a) See Note 10 of the Notes to Consolidated Financial Statements, "Long-Term Debt," for individual long-term debt maturities.
(b) We calculate interest on our variable rate debt based on the effective interest rate at December 31, 2005.
(c) Pension benefit funding obligations represent only the minimum funding requirements under the Employee Retirement Income Securities Act of 1974. Minimum funding requirements for future periods are not yet known. Our funding policy is to contribute amounts sufficient to meet the minimum funding requirements plus additional amounts as deemed fiscally appropriate; therefore, actual contributions may differ from expected contributions. See Note 12 of the Notes to Consolidated Financial Statements, "Wolf Creek Employee Benefit Plans," for additional information regarding pensions.
(d) Includes the La Cygne unit 2 lease, office space, operating facilities, office equipment, operating equipment and other miscellaneous commitments.
(e) Coal and natural gas commodity and transportation contracts.
(f) Uranium concentrates, conversion, enrichment, fabrication and spent nuclear fuel disposal.
(g) We have an obligation to pay rebates to customers in 2006.

OTHER INFORMATION

Payment of Rebates

On July 25, 2003, the KCC issued an order approving a Stipulation and Agreement, the principal terms of which included a requirement for Westar Energy and us to pay customer rebates of $10.5 million on May 1, 2005 and $10.0 million on January 1, 2006. Our share of the first rebate, approximately $5.6 million, appeared as credits on customers' billing statements in May and June of 2005. Our share of the second rebate, approximately $5.0 million, appeared as credits on customers' billing statements in January of 2006.

Impact of Regulatory Accounting

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.

At December 31, 2005, we had recorded regulatory assets currently subject to recovery in future rates of approximately $276.0 million and regulatory liabilities of $32.1 million as discussed in greater detail in Note 2 of the Notes to Consolidated Financial Statements, "Summary of Significant Accounting Policies – Regulatory Accounting." We believe that it is probable that our regulatory assets will be recovered in the future.

Asset Retirement Obligations

In accordance with SFAS No. 143, adopted January 2003, and FIN 47, adopted December 31, 2005, we have recognized legal obligations associated with the disposal 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.

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Legal Liability

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 fair 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.

During 2005 we updated our nuclear decommissioning and dismantlement study. Based on the results of the 2005 study, we have revised our estimate of our Wolf Creek asset retirement obligation. Accordingly, in 2005 we increased our asset retirement liability $14.6 million. Costs to retire Wolf Creek are currently being recovered through rates as provided by the KCC.

During 2005 we determined that we have conditional asset retirement obligations that are within the scope of FIN 47. The conditional asset retirement obligations include disposal of asbestos insulating material at our power plants, remediation of ash disposal ponds and the disposal of polychlorinated biphenyl (PCB) contaminated oil. As of December 31, 2005, we recorded an asset retirement obligation of approximately $14.7 million pursuant to the requirements of FIN 47 based on the fair value of these disposal obligations.

The amount of the retirement obligation related to asbestos disposal was recorded as of 1990, the date when the Environmental Protection Agency published the "National Emission Standards for Hazardous Air Pollutants: Asbestos NESHAP Revision; Final Rule." We also capitalized the retirement obligation as an increase to the asset's carrying value. The amount of the asset retirement obligation related to asbestos disposal was $4.5 million at December 31, 2005.

We operate, as permitted by the state of Kansas, ash landfills at several of our power plants. We have determined that the closure of these facilities represents a conditional asset retirement obligation as defined by FIN 47. Accordingly, we have recognized an asset retirement obligation for the ash landfills. The liability was determined based upon the date each landfill was originally placed in service. The amount of the asset retirement obligation related to remediation of ash disposal ponds was $9.8 million at December 31, 2005.

PCB contaminates are contained within company electrical equipment, primarily transformers. We have determined that the disposal of PCB-contaminated equipment represents a conditional asset retirement obligation as defined by FIN 47. Accordingly, we have recognized an asset retirement obligation for the PCB-contaminated equipment. The liability was determined based upon the PCB regulations that originally became effective in 1978. The amount of the asset retirement obligation related to the disposal of PCB contaminated oil was $0.4 million at December 31, 2005.

For additional information on our legal asset retirement obligations, see Note 14 of the Notes to Consolidated Financial Statements, "Asset Retirement Obligations."

Non-Legal Liability – Cost of Removal

We recover in rates, as a component of depreciation, the costs to dispose of utility plant assets that do not represent legal retirement obligations. We had $6.9 million in amounts collected, but unspent, for removal costs classified as a regulatory liability at December 31, 2005 and $2.6 million at December 31, 2004. The net amount related to non-legal retirement costs can fluctuate based on amounts recovered in rates compared to removal costs incurred.

New Accounting Pronouncements – Accounting Changes and Error Corrections

On May 30, 2005, the FASB issued SFAS No. 154, "Accounting Changes and Error Corrections – Replacement of APB 20 and SFAS No. 3," which changes the requirements for the accounting and reporting of a change in accounting principle. SFAS No. 154 applies to all voluntary changes in accounting principle as well as to changes required by an accounting pronouncement that does not include specific transition provisions. For most accounting changes and error corrections, SFAS No. 154 requires retrospective application, under which the new accounting principle is applied as of the beginning of the first period presented as if that principle had always been used. SFAS No. 154 is effective for accounting changes and corrections of errors made beginning January 1, 2006.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Hedging Activity

Westar Energy and we jointly use derivative financial and physical instruments to economically hedge the price of 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 market risk associated with fuel and energy prices, we may use economic hedging arrangements to reduce our exposure to price changes. Our future exposure to changes in prices will be dependent on the market prices and the extent and effectiveness of any economic hedging arrangements into which we enter.

See Note 5 of the Notes to Consolidated Financial Statements, "Financial Instruments, Energy Marketing and Risk Management — Derivative Instruments and Hedge Accounting — Hedging Activities," for detailed information regarding hedging relationships entered into during the third quarter of 2001.

Market Price Risks

Our economic 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. We believe we will continue to experience volatility in the prices for these commodities.

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 risk with our retail, wholesale and energy marketing activities. We maintain credit policies intended to reduce overall credit risk. We employ additional credit risk control mechanisms that we believe are appropriate, such as letters of credit, parental guarantees and master netting agreements with counterparties that allow for offsetting exposures. Results actually achieved from economic 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 outside of trading activities. We use derivative contracts for non-trading purposes and a mix of various fuel types primarily to reduce exposure relative to the volatility of market and commodity prices. The wholesale power market is extremely volatile in price and supply. This volatility impacts our costs of power purchased and our participation in energy trades. If we were unable to generate an adequate supply of electricity for our 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 permitted in our tariffs and terms and conditions of service. The loss of revenues associated with this could be material and adverse to our consolidated results of operations and financial condition.

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 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 have entered into various fixed and variable rate debt obligations. For details, see Note 10 of the Notes to Consolidated Financial Statements, "Long-Term Debt." Sensitivity to changes in interest rates for variable rate debt and current maturities of fixed rate debt is computed by assuming a 100 basis point change in the current interest rate applicable to such debt over the remaining time the debt is outstanding.

We had approximately $246.4 million of variable rate debt and current maturities of fixed rate debt at December 31, 2005. A 100 basis point change in interest rates applicable to this debt would impact operating income on an annualized basis by approximately $1.5 million.

Security Price Risk

We maintain trust funds, as required by the NRC and Kansas state laws, to fund certain costs of nuclear plant decommissioning. As of December 31, 2005, these funds were comprised of 66% domestic equity securities, 24% debt securities and 10% cash and cash equivalents. The fair value of these funds was $100.8 million as of December 31, 2005 and $91.1 million as of December 31, 2004. By maintaining a portfolio that includes long-term equity investments, we seek to maximize the returns to be utilized to fund nuclear decommissioning costs within acceptable parameters of risk. However, the equity securities included in the portfolio are exposed to price fluctuations in equity markets and the fixed-rate, fixed-income securities are exposed to changes in interest rates. We actively monitor the portfolio by benchmarking the performance of the investments against certain indices and by maintaining and periodically reviewing established target allocation percentages of the assets of the trusts to various investment options. Our exposure to equity price market risk is, in large part, mitigated, due to the fact that we are currently allowed to recover decommissioning costs in our electric rates, which would include unfavorable investment results.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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SCHEDULES OMITTED

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

I, III, IV, and V.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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, 2005 and 2004, and the related consolidated statements of income and comprehensive income, shareholder's equity, and cash flows for each of the three years in the period ended December 31, 2005. Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, 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 Kansas Gas and Electric Company as of December 31, 2005 and 2004, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2005, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

As discussed in Note 2 to the consolidated financial statements, in 2005, the Company changed the presentation of its consolidated statements of cash flows and retroactively revised the consolidated statements of cash flows for the years ended December 31, 2004 and 2003.

/s/ Deloitte & Touche LLP

Kansas City, Missouri
March 10, 2006

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KANSAS GAS AND ELECTRIC COMPANY

CONSOLIDATED BALANCE SHEETS
(Dollars in Thousands)

	As of December 31, 2005	As of December 31, 2004
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 2,478	$ 812
Accounts receivable, net	124,408	92,284
Inventories and supplies, net	57,668	64,397
Energy marketing contracts	3,869	4,020
Deferred tax assets	4,320	544
Prepaid expenses	25,245	24,070
Regulatory assets	17,326	4,852
Other	2,136	2,633
Total Current Assets	237,450	193,612
PROPERTY, PLANT AND EQUIPMENT, NET	2,341,388	2,349,673
OTHER ASSETS:		
Regulatory assets	258,683	239,158
Nuclear decommissioning trust	100,803	91,095
Other	33,255	40,303
Total Other Assets	392,741	370,556
TOTAL ASSETS	$2,971,579	$2,913,841
LIABILITIES AND SHAREHOLDER'S EQUITY		
CURRENT LIABILITIES:		
Current maturities of long-term debt	$ 100,000	$ 65,000
Accounts payable	26,088	39,772
Payable to affiliates	154,630	91,504
Accrued interest	6,092	7,308
Accrued taxes	35,499	29,420
Energy marketing contracts	4,170	2,497
Other	35,140	31,632
Total Current Liabilities	361,619	267,133
LONG-TERM LIABILITIES:		
Long-term debt, net	387,427	487,419
Deferred income taxes	637,226	656,838
Unamortized investment tax credits	44,105	46,073
Deferred gain from sale-leaseback	130,513	138,981
Asset retirement obligation	123,412	87,118
Other	132,673	138,473
Total Long-Term Liabilities	1,455,356	1,554,902
COMMITMENTS AND CONTINGENCIES (Note 13)		
SHAREHOLDER'S EQUITY:		
Common stock, without par value; authorized and issued 1,000 shares	1,065,634	1,065,634
Accumulated other comprehensive loss, net	(2,779)	—
Retained earnings	91,749	26,172
Total Shareholder's Equity	1,154,604	1,091,806
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$2,971,579	$2,913,841

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

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KANSAS GAS AND ELECTRIC COMPANY

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

	Year Ended December 31,		
	2005	2004	2003
SALES	$771,687	$714,939	$709,654
OPERATING EXPENSES:			
Fuel and purchased power	241,962	181,039	177,975
Operating and maintenance	242,418	229,587	221,667
Depreciation and amortization	80,482	91,835	90,604
Selling, general and administrative	82,939	75,105	70,737
Total Operating Expenses	647,801	577,566	560,983
INCOME FROM OPERATIONS	123,886	137,373	148,671
OTHER INCOME (EXPENSE):			
Other income	40,531	25,353	13,921
Other expense	(17,582)	(14,880)	(14,412)
Total Other Income (Expense)	22,949	10,473	(491)
Interest Expense	28,522	32,060	54,550
INCOME FROM OPERATIONS BEFORE INCOME TAXES	118,313	115,786	93,630
Income tax expense	32,736	34,558	27,003
NET INCOME	$ 85,577	$ 81,228	$ 66,627
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX:			
Unrealized holding gain on cash flow hedges	$ —	$ —	$ 2,421
Adjustment for gain included in net income	—	—	(3,135)
Minimum pension liability adjustment	(4,614)	—	—
Income tax benefit related to items of other comprehensive income	1,835	—	284
Total Other Comprehensive Loss, Net of Tax	(2,779)	—	(430)
COMPREHENSIVE INCOME	$ 82,798	$ 81,228	$ 66,197

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, 2005	2004 Revised (See Note 2)	2003 Revised (See Note 2)
CASH FLOWS FROM (USED IN) OPERATING ACTIVITIES:			
Net income	$ 85,577	$ 81,228	$ 66,627
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	80,482	91,835	90,604
Amortization of nuclear fuel	13,315	14,221	12,410
Amortization of deferred gain from sale-leaseback	(8,469)	(11,828)	(11,828)
Amortization of corporate-owned life insurance	13,510	12,764	12,060
Net deferred taxes	1,780	(13,402)	4,469
Net changes in energy marketing assets and liabilities	2,109	388	739
Gain on sale of property	—	(503)	—
Changes in working capital items:			
Accounts receivable, net	(32,124)	(11,513)	(31,993)
Inventories and supplies	6,729	2,085	(926)
Prepaid expenses and other	(57,477)	(39,318)	(47,357)
Accounts payable	(13,100)	(2,724)	9,168
Payable to affiliates	62,745	10,124	26,517
Other current liabilities	4,981	1,873	2,930
Changes in other, assets	(14,423)	(4,615)	62,734
Changes in other, liabilities	(16,488)	6,624	(56,286)
Cash flows from operating activities	129,147	137,239	139,868
CASH FLOWS FROM (USED IN) INVESTING ACTIVITIES:			
Additions to property, plant and equipment	(87,172)	(99,030)	(89,184)
Purchase of securities within the nuclear decommissioning trust fund	(372,426)	(313,241)	(235,890)
Sale of securities within the nuclear decommissioning trust fund	367,570	309,105	228,737
Investment in corporate-owned life insurance	(19,346)	(19,658)	(19,599)
Proceeds from investment in corporate-owned life insurance	10,997	—	—
Proceeds from sale of property	—	1,506	—
Proceeds from other investments	11,734	4,077	7,166
Cash flows used in investing activities	(88,643)	(117,241)	(108,770)
CASH FLOWS FROM (USED IN) FINANCING ACTIVITIES:			
Proceeds from long-term debt	—	321,540	—
Retirements of long-term debt	(65,000)	(329,137)	(135,005)
Funds in trust for debt repayments	—	—	145,260
Borrowings against cash surrender value of corporate-owned life insurance	58,039	57,090	58,818
Repayment of borrowings against cash surrender value of corporate-owned life insurance	(11,877)	—	—
Dividends to parent company	(20,000)	(75,000)	(100,000)
Cash flows used in financing activities	(38,838)	(25,507)	(30,927)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	1,666	(5,509)	171
CASH AND CASH EQUIVALENTS:			
Beginning of period	812	6,321	6,150
End of period	$ 2,478	$ 812	$ 6,321
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION:			
CASH PAID FOR:			
Interest on financing activities, net of amount capitalized	$ 26,041	$ 30,133	$ 44,696

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

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KANSAS GAS AND ELECTRIC COMPANY

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

	Year Ended December 31, 2005	2004	2003
Common Stock	$1,065,634	$1,065,634	$1,065,634
Accumulated other comprehensive income (loss):			
Beginning balance	—	—	430
Unrealized holding gain on cash flow hedges	—	—	2,421
Adjustment for gain included in net income	—	—	(3,135)
Minimum pension liability adjustment	(4,614)	—	—
Tax benefit	1,835	—	284
Accumulated other comprehensive loss	(2,779)	—	—
Retained Earnings:			
Beginning balance	26,172	19,944	53,317
Net income	85,577	81,228	66,627
Dividends to parent company	(20,000)	(75,000)	(100,000)
Ending balance	91,749	26,172	19,944
Total Shareholder's Equity	$1,154,604	$1,091,806	$1,085,578

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

KANSAS GAS AND ELECTRIC COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. DESCRIPTION OF BUSINESS

Kansas Gas and Electric Company is a regulated electric utility incorporated in 1990 in 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. 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 305,000 customers in south-central and southeastern Kansas, including the city of Wichita. We own a 47% interest in the Wolf Creek Generating Station (Wolf Creek), a nuclear power plant located near Burlington, Kansas. Our corporate headquarters is located in Wichita, Kansas.

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 our undivided interests in jointly-owned generation facilities on a proportionate basis. All material intercompany accounts and transactions have been eliminated in consolidation. In our opinion, all adjustments, consisting only of normal recurring adjustments considered necessary for a fair presentation of the financial statements, have been included.

Use of Management’s Estimates

When we prepare our consolidated financial statements, we are required to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities at the date of our consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. We evaluate our estimates on an on-going basis, including those related to bad debts, inventories, valuation of commodity contracts, depreciation, unbilled revenue, investments, valuation of our energy marketing portfolio, intangible assets, income taxes, our portion of the Wolf Creek pension and other post-retirement benefits, our asset retirement obligations including decommissioning of Wolf Creek, 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 of costs that are not likely to be incurred in the future. Regulatory assets and liabilities reflected on our consolidated balance sheets are as follows.

	As of December 31, 2005	2004
	(In Thousands)	
Amounts due from customers for future income taxes, net	$123,997	$144,817
Debt reacquisition costs	29,245	26,264
Disallowed plant costs	16,929	27,979
2002 ice storm costs	11,724	10,748
2005 ice storm costs	25,339	—
Asset retirement obligations	13,298	—
Depreciation	41,795	22,596
Wolf Creek outage	9,915	6,467
Other regulatory assets	3,767	5,139
Total regulatory assets	$276,009	$244,010
Nuclear decommissioning	$ 16,048	$ 13,745
Other regulatory liabilities	16,032	9,045
Total regulatory liabilities	$ 32,080	$ 22,790

Below we summarize the nature and period of recovery for each of the regulatory assets listed in the table above.

- **Amounts due from customers for future income taxes, net:** In accordance with various rate orders, we have reduced rates to reflect the tax benefits associated with certain tax deductions. We believe it is probable that the net future increases in income taxes payable will be recovered from customers when these temporary tax benefits reverse. We have recorded a regulatory asset for these amounts. We also have recorded a regulatory liability for our obligation to reduce rates charged customers for deferred taxes recovered from customers at corporate tax rates higher than the current tax rates. The rate reduction will occur as the temporary differences resulting in the excess deferred tax liabilities reverse. The tax-related regulatory assets and liabilities as well as unamortized investment tax credits are also temporary differences for which deferred income taxes have been provided. These items are measured by the expected cash flows to be received or settled through future rates. The net regulatory asset for these tax items is classified above as amounts due from customers for future income taxes.
- **Debt reacquisition costs**: Includes costs incurred to reacquire and refinance debt. Debt reacquisition costs are amortized over the term of the new debt.
- **Disallowed plant costs:** In 1985, the KCC disallowed certain costs associated with the original construction of Wolf Creek. In 1987, the KCC authorized us to recover these costs in rates over the useful life of Wolf Creek. See Note 3, “Rate Matters and Regulation,” for additional information.
- **2002 ice storm costs:** We accumulated and deferred for recovery costs related to system restoration from an ice storm that occurred in January 2002. We were authorized to accrue carrying costs on this item. Recovery of these costs will occur over a five year period beginning in 2006 as allowed by the December 28, 2005 Kansas Corporation Commission (KCC) Order. We earn a return on this asset.

- **2005 ice storm costs:** We accumulated and deferred for future recovery costs related to system restoration from an ice storm that occurred in January 2005. We were authorized to accrue carrying costs on this item. Recovery of these costs will occur over a five year period beginning in 2006 as allowed by the December 28, 2005 KCC Order. We earn a return on this asset.
- **Asset retirement obligations:** Represents amounts associated with our asset retirement obligations as discussed in Note 14, "Asset Retirement Obligations." We recover this item over the life of the utility plant.
- **Depreciation:** Represents the difference between the KCC allowed depreciation expense and the depreciation expense recorded for financial statement purposes. The increase in the depreciation regulatory asset is due primarily to recognizing differences in depreciation pursuant to the December 28, 2005 KCC Order. We earn a return on this asset. We recover this item over the life of the related utility plant.
- **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 individually are relatively small in relation to the total regulatory asset balance. Other regulatory assets have various recovery periods, most of which range from one to five years.

Below we summarize the nature and period of amortization for each of the regulatory liabilities listed in the table above.

- **Nuclear decommissioning:** Represents amounts received from customers to fund our legal obligation to decommission Wolf Creek. We recover decommissioning costs in rates as provided by the KCC. We have placed amounts recovered in a trust. See Note 14, "Asset Retirement Obligations," for information regarding our Nuclear Decommissioning Trust Fund. The recovery period is through the expiration of Wolf Creek's operating license in 2025. The nuclear decommissioning regulatory liability is included in other long-term liabilities on our consolidated balance sheets.
- **Other regulatory liabilities:** This includes various regulatory liabilities that individually are relatively small in relation to the total regulatory liability balance. Other regulatory liabilities will be credited over various periods, most of which range from one to five years. Other regulatory liabilities are included in other long-term liabilities on our consolidated balance sheets.

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 4.2% in 2005, 3.8% in 2004 and 5.3% in 2003. The cost of additions to utility plant and replacement units of property is capitalized. AFUDC capitalized was $1.4 million in 2005, $1.1 million in 2004 and $0.9 million in 2003.

Maintenance costs and replacement of minor items of property are charged to expense as incurred. Normally, 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 a straight-line method at 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% in 2005, 2004 and 2003.

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

	Years
Fossil fuel generating facilities	6 to 68
Nuclear fuel generating facility	38 to 40
Transmission facilities	28 to 65
Distribution facilities	19 to 57
Other	5 to 55

In its order on December 28, 2005, the KCC approved a change in our depreciation rates allowing for inclusion of net salvage costs, which include the ultimate cost of dismantlement of plant facilities. This change, along with other changes in estimated useful lives, will result in an annual increase in the recovery of depreciation expense of approximately $13.4 million.

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 fuel and purchased power 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 $24.2 million at December 31, 2005 and $30.9 million at December 31, 2004. Spent nuclear fuel charged to fuel and purchased power was $18.0 million in 2005, $19.3 million in 2004 and $17.0 million in 2003.

Cash Surrender Value of Life Insurance

We recorded the following amounts related to corporate-owned life insurance policies in other long-term assets on our consolidated balance sheets.

	As of December 31,	
	2005	2004
	(In Thousands)	
Cash surrender value of policies	$ 871,781	$ 825,268
Borrowings against policies	(858,309)	(812,096)
Corporate-owned life insurance, net	$ 13,472	$ 13,172

Income is recorded for increases in cash surrender value and death proceeds. Interest incurred on amounts borrowed is offset against policy income. Income recognized from death proceeds is highly variable from period to period. Death benefits recognized as income on our consolidated statements of income approximated $8.2 million in 2005, $0.8 million in 2004 and $0.2 million in 2003.

Revenue Recognition – Energy Sales

We recognize revenues from retail energy sales upon delivery to the customer and include an estimate for energy delivered but unbilled. Our estimate of revenue attributable to this unbilled portion is based on the total energy available for sale measured against billed sales. At December 31, 2005, we had estimated unbilled revenue of $21.2 million.

We are allocated a share of revenues from energy marketing derivative contracts 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. We account for energy marketing derivative contracts under the mark-to-market method of accounting. Under this method, we recognize changes in the portfolio value as gains or losses in the period of change. With the exception of fuel contracts, we include the net mark-to-market change in sales on our consolidated statements of income. We record the resulting unrealized gains and losses as energy marketing long-term or short-term assets and liabilities on our consolidated balance sheets as appropriate. We use quoted market prices to value our energy marketing derivative contracts when such data are available. When market prices are not readily available or determinable, we use alternative approaches, such as model pricing. Prices used to value these transactions reflect our best estimate of fair values of our trading positions.

Income Taxes

We use the asset and liability method of accounting for income taxes as required by SFAS No. 109, “Accounting for Income Taxes.” Under the asset and liability method, we recognize deferred tax assets and liabilities for the future tax consequences attributable to temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. We recognize the future tax benefits to the extent that realization of such benefits is more likely than not. We amortize deferred investment tax credits over the lives of the related properties.

New Accounting Pronouncements – Accounting Changes and Error Corrections

On May 30, 2005, the Financial Accounting Standards Board (FASB) issued SFAS No. 154, “Accounting Changes and Error Corrections – Replacement of APB 20 and SFAS No. 3,” which changes the requirements for the accounting and reporting of a change in accounting principle. SFAS No. 154 applies to all voluntary changes in accounting principle as well as to changes required by an accounting pronouncement that does not include specific transition provisions. For most accounting changes and error corrections, SFAS No. 154 requires retrospective application, under which the new accounting principle is applied as of the beginning of the first period presented as if that principle had always been used. SFAS No. 154 is effective for accounting changes and corrections of errors made beginning January 1, 2006.

Reclassifications and Revisions

We have reclassified and revised certain prior year amounts to conform with classifications used in the current-year presentation as necessary for a fair presentation of the financial statements.

We previously presented our asset retirement obligation associated with Wolf Creek as a regulatory asset. We have reclassified this amount to offset amounts collected from customers that were previously recorded as nuclear decommissioning accrual.

We have revised the prior years' presentation of our consolidated statements of cash flows to present the investments in and proceeds from purchases and sales of marketable securities in our nuclear decommissioning trust on a gross basis, rather than net. In addition, we revised the cash flows associated with construction work in progress that had not been paid as of year-end. As a result, we reclassified $0.3 million and $1.0 million for the years ended December 31, 2004 and 2003, respectively, to cash flows from operating activities, from additions to property, plant and equipment in cash flows used in investing activities.

3. RATE MATTERS AND REGULATION

Retail Rate Review

December 28, 2005 KCC Order

In accordance with a 2003 KCC order, Westar Energy and we filed applications with the KCC on May 2, 2005 to review our rates. We requested an increase in our retail electric rates and the adoption of other practices under the KCC's jurisdiction. The KCC ordered a decrease in our base rates of $3.1 million annually and requires that we credit to retail customers a rolling three-year average of the margins we realize from our market-based wholesale sales. Other significant changes approved by the KCC are a retail energy cost adjustment (RECA), an environmental cost recovery rider (ECRR), the separation of transmission delivery charges, an increase in annual depreciation expense, an extended recovery period for costs being recovered for which no return is provided and the recovery of various costs that have been incurred and deferred as regulatory assets.

Retail Energy Cost Adjustment: The RECA allows us to recover the actual cost of fuel consumed in producing electricity and the cost of purchased power. The adjustment is based on the actual cost of fuel and purchased power less margins from market-based wholesale sales. We have contracts with certain large industrial customers, the terms of which do not provide for the separate billing of fuel costs. Fuel costs for these customers will continue to be recovered through the rates specified in each of these contracts. These customers represented approximately 16% of our total retail sales volumes for 2005.

Wholesale Sales Margins: The terms of the RECA require that we include, as a credit to recoverable fuel costs, an amount based on the average of the margins realized from market-based wholesale sales during the immediately prior three-year period. In any period we are unable to realize market-based wholesale sales margins at least equal to the amount of the credit, our financial results would be adversely affected. In the short-term, our generating capacity is fixed while the load requirements of our customers change constantly. When our generating capacity is not needed to serve our customers, we attempt to seek out wholesale sales of energy at prices in excess of the costs of production. We are likely to face the prospect of decreasing margins as the energy demands of our retail customers increase, which may result in crediting to retail customers an amount that would exceed the margins realized in the current period.

Environmental Cost Recovery Rider: The ECRR allows for the timely inclusion in rates, without requiring a full rate review, of the capital expenditures made to upgrade our equipment to meet stricter environmental standards required by the Clean Air Act. Prior to collection through rates, the KCC will review any environmental expenditures to be considered for recovery under the ECRR. Any increased operating and maintenance costs that result from updating or adding environmental equipment cannot be recovered through the ECRR. These costs would be addressed in future rate reviews.

Transmission Delivery Charge: The December 28, 2005 KCC Order allows us to separate our transmission costs from our base rates charged to retail customers. This allows us to implement a formula transmission rate that provides for annual adjustments to reflect changes in our transmission costs, which provides for adjustment on a more timely basis. These rates were proposed in an application filed with FERC on May 2, 2005 and became effective on December 1, 2005, subject to refund upon review and approval by FERC.

Depreciation Rates: The December 28, 2005 KCC Order authorized an annual increase in the recovery of depreciation expense of approximately $13.4 million. The approved change in depreciation rates allows for the inclusion of net salvage costs, which include an estimate for the cost of dismantlement of plant facilities.

Disallowed Plant Costs: In 1985, the KCC disallowed certain costs associated with the original construction of Wolf Creek. In 1987, the KCC authorized us to recover these costs in rates over the original depreciable life of Wolf Creek, or through 2025, but disallowed any return on these costs. In its December 28, 2005 order, the KCC extended the recovery period to correspond to Wolf Creek's new estimated depreciable life. We recognized a loss of $10.4 million in the fourth quarter of 2005 as a result of the decrease in the present value of amounts to be received due to the extension of the recovery period.

Other Regulatory Assets: The December 28, 2005 KCC Order also approved for recovery approximately $37.1 million of deferred maintenance costs associated with restoring utility service to our customers stemming from damage to our lines and equipment in the ice storms that occurred in 2002 and 2005 and various other expenses that are relatively small in relation to the total regulatory asset balance.

FERC Proceedings

Request for Change in Transmission Rates

On May 2, 2005, Westar Energy and we filed applications with FERC that propose a formula transmission rate that provides for annual adjustments to reflect changes in Westar Energy's and our transmission costs. This is consistent with our proposals filed with the KCC on May 2, 2005 to separately charge retail customers for transmission service. These rates became effective on December 1, 2005, subject to refund. We can provide no assurance that FERC will ultimately approve our applications as filed.

Market-based Rates

On March 23, 2005, FERC instituted a proceeding concerning the reasonableness of Westar Energy's and our market-based rates in our electric control area and the electrical control areas of Midwest Energy, Inc. and Aquila, Inc.'s West Plains Energy division. Westar Energy and we have provided FERC with information it requested for its analysis. A FERC decision, anticipated in 2006, could affect how we price future wholesale power sales to wholesale customers in our control area and to Midwest Energy and West Plains Energy and wholesale customers in their control areas. We do not expect the outcome of this matter to significantly impact our consolidated results of operations.

4. ACCOUNTS RECEIVABLE SALES PROGRAM

We sell our accounts receivable, without recourse, to WR Receivables Corporation, a wholly owned subsidiary. WR Receivables may sell up to $125.0 million of an undivided interest in this pool of receivables to a bank and commercial paper conduit pursuant to an agreement entered into in 2000. We renewed the agreement in July 2005 for one year on terms substantially similar to the expiring agreement. This transaction constitutes a sale of receivables in accordance with SFAS No. 140. WR Receivables has no ownership interest in the bank or commercial paper conduit and is not required to consolidate these entities in accordance with GAAP.

The receivables sold by WR Receivables to the bank and commercial paper conduit are not reflected in the accounts receivable balance in the accompanying consolidated balance sheets. The amounts sold to the bank and commercial paper conduit were $65.0 million at December 31, 2005 and $80.0 million at December 31, 2004. We record this activity on the consolidated statements of cash flows in the "accounts receivable, net" line of cash flows from operating activities.

We service, administer and collect the receivables on behalf of the bank and commercial paper conduit. WR Receivables incurred a loss on the sale of the accounts receivable sold to the commercial paper conduit of $3.3 million in 2005, $2.1 million in 2004 and $2.4 million in 2003. We include this loss in other expense on our consolidated statements of income.

We record the sale of receivables to WR Receivables at book value, net of allowance for bad debts. This approximates fair value due to the short-term nature of the receivables. We include the accounts receivables retained by WR Receivables in accounts receivable, net, on our consolidated balance sheets.

The following table summarizes comparative accounts receivable information for WR Receivables.

	As of December 31,	
	2005	2004
	(In Thousands)	
Proceeds from the sale of accounts receivables	$ 1,034,459	$ 1,041,258
Loss on sale of accounts receivables	3,339	2,114
Accounts receivable retained interest and pledged as collateral less uncollectible accounts	19,956	10,023
Retained interest if 10% adverse change in uncollectible accounts	19,794	9,792
Retained interest if 20% adverse change in uncollectible accounts	19,629	9,559

The following table shows the historical loss and delinquency amounts for the customer accounts receivable managed portfolio.

	As of December 31,	
	2005	2004
	(In Thousands)	
Customer accounts receivable	$128,868	$ 97,017
Allowance for uncollectible accounts	(4,933)	(5,152)
Customer accounts receivable, net	123,935	91,865
Other accounts receivable	533	475
Other allowance for uncollectible accounts	(60)	(56)
Total balance sheet accounts receivable, net	124,408	92,284
Customer accounts receivable sold	65,000	80,000
Total accounts receivable managed	$189,408	$172,284
Net uncollectible accounts written off	$ 3,862	$ 2,751
Delinquent customer accounts receivable over 60 days	$ 2,994	$ 2,939

5. FINANCIAL INSTRUMENTS, ENERGY MARKETING AND RISK MANAGEMENT

Values of Financial Instruments

We estimate the fair value of each class of our financial instruments for which it is practicable to estimate that value as set forth in SFAS No. 107, “Disclosures about Fair Value of Financial Instruments.”

Cash and cash equivalents, short-term borrowings and variable-rate debt are carried at cost, which approximates fair value. The nuclear decommissioning trust is recorded at fair value, which is estimated based on the quoted market prices at December 31, 2005 and 2004. See Note 6, “Financial Investments and Trading Securities,” for additional information about our nuclear decommissioning trust. The fair value of fixed-rate debt 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.

The fair value estimates are based on information available at December 31, 2005 and 2004. These fair value estimates have not been comprehensively revalued for the purpose of these financial statements since that date and current estimates of fair value may differ from the amounts below. The carrying values and estimated fair values of our financial instruments are as shown in the table below.

	Carrying Value		Fair Value	
	As of December 31,			
	2005	2004	2005	2004
	(In Thousands)			
Fixed-rate debt, net of current maturities	$240,988	$340,988	$246,696	$354,079

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, economically hedge a portion of these risks through the use of derivative financial instruments. We use the term economic 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 marketing purposes.

Westar Energy and we jointly use derivative financial and physical instruments primarily to manage risk as it relates to changes in the prices of commodities including natural gas, oil, coal and electricity. We classify derivative instruments used to manage commodity price risk inherent in fossil fuel and electricity purchases and sales as energy marketing contracts on our consolidated balance sheets. We report energy marketing contracts representing unrealized gain positions as assets; energy marketing contracts representing unrealized loss positions are reported as liabilities.

Energy Marketing Activities

We engage in both financial and physical trading to increase profits, manage our commodity price risk and enhance system reliability. We trade electricity, coal, natural gas and oil. We use a variety of financial instruments, including forward contracts, options and swaps, and we trade energy commodity contracts.

Within the trading portfolio, we take certain positions to economically hedge a portion of physical sale or purchase contracts and we take certain positions to take advantage of market trends and conditions. With the exception of fuel contracts, we reflect changes in value 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 marketing activities.

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

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

We are also exposed to commodity price changes. We use derivative contracts for non-trading purposes and a mix of various fuel types primarily to reduce exposure relative to the volatility of market and commodity prices. The wholesale power market is extremely volatile in price and supply. This volatility impacts our costs of power purchased and our participation in energy trades. If we were unable to generate an adequate supply of electricity for our 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 permitted in our tariffs and terms and conditions of service.

We use various fossil fuel types, including coal, natural gas and oil, to operate our plants. A significant portion of our coal requirements are purchased under long-term contracts. Due to the volatility of natural gas prices, we have increasingly operated facilities that have allowed us to use lower cost fuel types as generating unit constraints and environmental restrictions allow, primarily by using oil in our facilities that also burn natural gas.

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 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.

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.

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. We 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 natural gas purchases. As a result, we recognized in income a gain of $1.8 million.

6. FINANCIAL INVESTMENTS AND TRADING SECURITIES

Some of our investments in debt and equity securities are subject to the requirements of SFAS No. 115, “Accounting for Certain Investments in Debt and Equity Securities.” We report these investments at fair value and we use the specific identification method to determine their cost for computing realized gains or losses. We classify these investments as either trading securities or available-for-sale securities as described below.

Available-for-Sale Securities

We have investments in debt and equity securities that are held in trust funds for the purpose of funding the decommissioning of our Wolf Creek nuclear plant. We have classified these investments in debt and equity securities as available-for-sale and have recorded all such investments at their fair market value at December 31, 2005 and 2004. Investments by the nuclear decommissioning trust fund are allocated 66% to equity securities, with the balance invested in fixed-income securities, cash and cash equivalents. Fixed-income investments are limited to U.S. government or agency securities, municipal bonds, or investment-grade corporate securities. Using the specific identification method to determine cost, the gross realized gains on those sales were $3.2 million for 2005, $4.3 million for 2004 and $1.9 million for 2003. Net realized and unrealized gains and losses are reflected in regulatory liabilities on our consolidated balance sheets. This reporting is consistent with the method we use to account for the decommissioning costs recovered in rates. Gains or losses on assets in the trust fund could result in lower or higher funding requirements for decommissioning costs, which we believe would be recovered in electric rates paid by our customers.

The following table presents the costs and fair values of investments in debt and equity securities in the nuclear decommissioning trust fund at December 31, 2005 and 2004. Changes in the fair value of the trust fund are recorded as an increase or decrease to the regulatory liability recorded in connection with the decommissioning of Wolf Creek.

Security Type	Cost	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
	(In Thousands)			
2005:				
Debt securities	$25,196	$ —	$(309)	$ 24,887
Equity securities	51,591	14,731	—	66,322
Cash equivalents	9,594	—	—	9,594
Total	$86,381	$14,731	$(309)	$100,803
2004:				
Debt securities	$28,574	$ 6	$ —	$ 28,580
Equity securities	46,566	12,224	—	58,790
Cash equivalents	3,725	—	—	3,725
Total	$78,865	$12,230	$ —	$ 91,095

The following table presents the costs and fair values of investments in debt securities in the nuclear decommissioning trust fund at December 31, 2005 according to their contractual maturities.

	Cost	Fair Value
	(In Thousands)	
Less than 5 years	$ 6,438	$ 6,325
5 years to 10 years	6,770	6,722
Due after 10 years	11,988	11,840
Total	$25,196	$ 24,887

7. PROPERTY, PLANT AND EQUIPMENT

The following is a summary of our property, plant and equipment balance.

	As of December 31, 2005	As of December 31, 2004
	(In Thousands)	
Electric plant in service	$ 3,145,148	$ 3,072,629
Electric plant acquisition adjustment	800,971	800,971
Accumulated depreciation	(1,666,267)	(1,595,241)
	2,279,852	2,278,359
Construction work in progress	33,830	35,302
Nuclear fuel, net	27,672	35,942
Net utility plant	2,341,354	2,349,603
Non-utility plant in service	34	70
Net property, plant and equipment	$ 2,341,388	$ 2,349,673

Depreciation expense on property, plant and equipment was $60.4 million in 2005, $71.7 million in 2004 and $70.5 million in 2003.

8. JOINT OWNERSHIP OF UTILITY PLANTS

Under joint ownership agreements with other utilities, we have undivided ownership interests in three electric generating stations. Energy generated and operating expenses are divided on the same basis as ownership with each owner reflecting its respective costs in its statements of income. Information relative to our ownership interest in these facilities at December 31, 2005 is shown in the table below.

		Our Ownership at December 31, 2005				
		In-Service Dates	Investment	Accumulated Depreciation	Net MW	Ownership Percent
			(Dollars in Thousands)			
La Cygne unit 1	(a)	June 1973	$ 219,638	$ 121,532	362.0	50
Jeffrey unit 1	(b)	July 1978	77,031	38,068	147.0	20
Jeffrey unit 2	(b)	May 1980	73,036	36,434	147.0	20
Jeffrey unit 3	(b)	May 1983	108,039	52,682	148.0	20
Jeffrey wind 1	(b)	May 1999	208	63	0.1	20
Jeffrey wind 2	(b)	May 1999	207	63	0.1	20
Wolf Creek	(c)	Sept. 1985	1,427,947	612,824	548.0	47

(a) Jointly owned with Kansas City Power & Light Company (KCPL)
(b) Jointly owned with Aquila, Inc. and Westar Energy.
(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 above plants, as well as such expenses for a 50% undivided interest in La Cygne unit 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. Our share of other transactions associated with the plants is included in the appropriate classification on our consolidated financial statements.

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9. SHORT-TERM BORROWINGS

We had no short-term borrowings outstanding at December 31, 2005 and 2004. Our short-term liquidity needs are met from cash advances by Westar Energy.

Westar Energy has an arrangement with a syndicate of banks to provide it a revolving credit facility on a committed basis totaling $350.0 million. The facility is secured by our first mortgage bonds and matures on May 6, 2010.

See Note 10, "Long-Term Debt," for a discussion of covenants applicable to Westar Energy's credit facilities.

10. LONG-TERM DEBT

Outstanding Debt

The following table summarizes our long-term debt outstanding.

	As of December 31,	
	2005	2004
	(In Thousands)	
First mortgage bond series:		
6.50% due 2005	$ —	$ 65,000
6.20% due 2006	100,000	100,000
	100,000	165,000
Pollution control bond series:		
5.10% due 2023	13,488	13,488
Variable due 2027, 3.35% at December 31, 2005; 1.75% at December 31, 2004	21,940	21,940
5.30% due 2031	108,600	108,600
5.30% due 2031	18,900	18,900
2.65% due 2031 and putable 2006	100,000	100,000
Variable due 2031, 3.49% at December 31, 2005; 1.92% at December 31, 2004	100,000	100,000
Variable due 2032, 3.30% at December 31, 2005; 1.67% at December 31, 2004	14,500	14,500
Variable due 2032, 3.25% at December 31, 2005; 1.85% at December 31, 2004	10,000	10,000
	387,428	387,428
Unamortized debt discount (a)	(1)	(9)
Long-term debt due within one year	(100,000)	(65,000)
Long-term debt, net	$ 387,427	$487,419

(a) We amortize debt discount over the term of the respective issue.

Our mortgage contains provisions restricting the amount of first mortgage bonds that we could issue. Therefore, we must ensure that we will be able to comply with such restrictions prior to the issuance of additional first mortgage bonds or other secured indebtedness.

The amount of our first mortgage bonds authorized by our Mortgage and Deed of Trust dated April 1, 1940, as supplemented, is limited to a maximum of $2.0 billion, unless amended. First mortgage bonds are secured by utility assets. Amounts of additional bonds that may be issued are subject to property, earnings and certain restrictive provisions, except in connection with certain refundings, of the mortgage. At December 31, 2005, based on an assumed interest rate of 6%, approximately $607.3 million principal amount of additional first mortgage bonds could be issued under the most restrictive provisions in the mortgage.

On January 17, 2006, we repaid the outstanding $100.0 million aggregate principal amount of our 6.2% first mortgage bonds with cash on hand and borrowings under the Westar Energy revolving credit facility. On August 1, 2005, we repaid the outstanding $65.0 million aggregate principal amount of our 6.5% first mortgage bonds with cash on hand and borrowings under the Westar Energy revolving credit facility.

On June 10, 2004, we refinanced $327.5 million of pollution control bonds. The original issue had an interest rate of 7% and was due in 2031. This issue was replaced with pollution control bonds at interest rates of 5.3% on $127.5 million that matures in 2031, 2.65% on $100.0 million that matures in 2031, and a variable rate on $100.0 million that matures in 2031.

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 calculates these ratios in accordance with its credit agreements. These ratios are used solely to determine compliance with its various debt covenants. Westar Energy was in compliance with these covenants at December 31, 2005.

Maturities

Maturities of long-term debt at December 31, 2005 are as follows.

Year	Principal Amount (In Thousands)
2006	$ 100,000
Thereafter	387,427
Total long-term debt maturities	$ 487,427

Our interest expense on long-term debt was $24.6 million in 2005, $29.6 million in 2004 and $46.5 million in 2003.

11. INCOME TAXES

Income tax expense (benefit) is composed of the following components.

	Year Ended December 31,		
	2005	2004	2003
		(In Thousands)	
Current income taxes:			
Federal	$24,844	$ 42,178	$18,074
State	6,112	5,782	4,460
Deferred income taxes:			
Federal	2,678	(10,282)	4,921
State	461	(1,076)	1,486
Investment tax credit amortization	(1,359)	(2,044)	(1,938)
Total income tax expense	$32,736	$ 34,558	$27,003

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

	December 31,	
	2005	2004
	(In Thousands)	
Current deferred tax assetst	$ 4,320	$ 544
Non-current deferred income tax liabilities	637,226	656,838
Net deferred tax liabilities	$632,906	$656,294

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

	December 31, 2005	December 31, 2004
	(In Thousands)	
Deferred tax assets:		
Deferred gain on sale-leaseback	$ 57,297	$ 61,241
Disallowed plant costs	16,617	13,484
General business credit carryforward (a)	8,443	10,746
Accrued liabilities	3,871	4,920
Other	27,445	25,321
Total deferred tax assets	$113,673	$115,712
Deferred tax liabilities:		
Accelerated depreciation	$366,781	$377,454
Acquisition premium	234,586	242,585
Amounts due from customers for future income taxes, net	123,997	144,817
Other	21,215	7,150
Total deferred tax liabilities	$746,579	$772,006
Net deferred tax liabilities	$632,906	$656,294

(a) Balance represents unutilized tax credits generated from affordable housing partnerships in which we sold the majority of our interests in 2001. These credits expire beginning 2019 through 2025.

In accordance with various rate orders, we have reduced rates to reflect the tax benefits associated with certain tax deductions. We believe it is probable that the net future increases in income taxes payable will be recovered from customers when these temporary tax benefits reverse. We have recorded a regulatory asset for these amounts. We also have recorded a regulatory liability for our obligation to reduce rates charged customers for deferred taxes recovered from customers at corporate tax rates higher than the current tax rates. The rate reduction will occur as the temporary differences resulting in the excess deferred tax liabilities reverse. The tax-related regulatory assets and liabilities as well as unamortized investment tax credits are also temporary differences for which deferred income taxes have been provided. The net deferred tax liability related to these temporary differences is classified above as amounts due from customers for 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, 2005	2004	2003
Statutory federal income tax rate	35.0%	35.0%	35.0%
Effect of:			
State income taxes	3.6	3.9	4.1
Amortization of investment tax credits	(1.1)	(1.8)	(2.1)
Corporate-owned life insurance policies	(11.9)	(10.4)	(13.3)
Accelerated depreciation flow through and amortization	2.6	3.6	5.3
Income tax reserve adjustment	0.2	2.5	—
Other	(0.7)	(2.9)	(0.2)
Effective income tax rate	27.7%	29.9%	28.8%

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. As of December 31, 2005, we owed Westar Energy $16.4 million for the 2005 tax year. The intercompany tax liability will be settled during 2006.

As of December 31, 2005 and 2004, we had recorded reserves for uncertain tax positions of $3.2 million and $2.9 million, respectively. The tax positions may involve income, deductions or credits reported in prior year income tax returns that we believe were treated properly on such tax returns. The tax returns containing these tax reporting positions are currently under audit or will likely be audited by the Internal Revenue Service or other taxing authorities. The timing of the resolution of these audits is uncertain. If the positions taken on the tax returns are ultimately upheld or not challenged within the time available for such challenges, we will reverse these tax provisions to income. If the positions taken on the tax returns are determined to be inappropriate, we may be required to make cash payments for taxes and interest. The reserves are determined based on our best estimate of probable assessments by the applicable taxing authorities and are adjusted, from time to time, based on changing facts and circumstances.

As of December 31, 2005 and 2004, we also had a reserve of $1.0 million and $0.9 million, respectively, for probable assessments of taxes other than income taxes.

12. WOLF CREEK EMPLOYEE BENEFIT PLANS

Pension and Post-retirement Benefits

The Wolf Creek pension plan expense and liabilities are measured using assumptions, which include discount rates, compensation rates and past and future estimated plan asset returns. Due to a decrease in interest rates and a corresponding decrease in the discount rates used to estimate pension liabilities, the fair value of the Wolf Creek pension plan assets was less than the accumulated benefit obligation at the measurement dates.

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As a co-owner of Wolf Creek, we are indirectly responsible for 47% of the liabilities and expenses associated with the Wolf Creek pension and post-retirement plans. We accrue our 47% of the cost of the Wolf Creek pension and post-retirement benefits during the years an employee provides service. The following tables summarize the net periodic costs for our 47% share of the Wolf Creek pension and post-retirement benefit plans.

	Pension Benefits		Post-retirement Benefits	
At December 31,	2005	2004	2005	2004
	(In Thousands)			
Change in Benefit Obligation:				
Benefit obligation, beginning of year	$ 59,168	$ 49,927	$ 6,102	$ 5,455
Service cost	2,820	2,572	238	235
Interest cost	3,730	3,295	384	356
Plan participants' contributions	—	—	193	147
Benefits paid	(992)	(849)	(515)	(416)
Actuarial losses	6,811	4,223	603	325
Benefit obligation, end of year	$ 71,537	$ 59,168	$ 7,005	$ 6,102
Change in Plan Assets:				
Fair value of plan assets, beginning of year	$ 32,491	$ 26,799	N/A	N/A
Actual return on plan assets	2,979	2,551	N/A	N/A
Employer contribution	5,084	3,810	N/A	N/A
Benefits paid	(802)	(669)	N/A	N/A
Fair value of plan assets, end of year	$ 39,752	$ 32,491	N/A	N/A
Funded status	$(31,785)	$(26,677)	$ (7,005)	$ (6,102)
Unrecognized net loss	20,850	15,239	2,645	2,211
Unrecognized transition obligation, net	342	398	403	461
Unrecognized prior service cost	188	220	—	—
Post-measurement date adjustments	205	740	—	—
Accrued post-retirement benefit costs	$(10,200)	$(10,080)	$ (3,957)	$ (3,430)
Amounts Recognized in the Balance Sheets Consist Of:				
Accrued benefit liability	$(10,200)	$(10,080)	$ (3,957)	$ (3,430)
Additional minimum liability	(5,144)	(3,144)	N/A	N/A
Intangible asset	530	618	N/A	N/A
Accumulated other comprehensive income	4,614	—	N/A	N/A
Regulatory asset	—	2,526	N/A	N/A
Net amount recognized	$(10,200)	$(10,080)	$ (3,957)	$ (3,430)

At December 31,	Pension Benefits 2005	Pension Benefits 2004	Post-retirement Benefits 2005	Post-retirement Benefits 2004
	(Dollars in Thousands)			
Accumulated Benefit Obligation	$55,302	$46,455	N/A	N/A
Pension Plans With a Projected Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$71,537	$59,168	N/A	N/A
Accumulated benefit obligation	55,302	46,455	N/A	N/A
Fair value of plan assets	39,752	32,491	N/A	N/A
Pension Plans With an Accumulated Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$71,537	$59,168	N/A	N/A
Accumulated benefit obligation	55,302	46,455	N/A	N/A
Fair value of plan assets	39,752	32,491	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	$ 7,005	$ 6,060
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	5.75%	6.00%	5.75%	6.00%
Compensation rate increase	3.25%	3.00%	N/A	N/A

Wolf Creek uses a measurement date of December 1 for the majority of its pension and post-retirement benefit plans.

Wolf Creek utilized the assistance of plan actuaries in determining the discount rate assumption at December 1, 2005. The actuaries have developed an interest rate yield curve to enable companies to make judgments pursuant to Emerging Issues Task Force (EITF) No. D-36, “Selection of Discount Rates Used for Measuring Defined Benefit Pension Obligations and Obligations of Post Retirement Benefit Plans Other Than Pensions.” The yield curve is constructed based on the yields on over 500 high-quality, non-callable corporate bonds with maturities between zero and 30 years. A theoretical spot rate curve constructed from this yield curve is then used to discount the annual benefit cash flows of Wolf Creek’s pension plan and develop a single-point discount rate matching the plan’s payout structure.

The prior service cost is amortized on a straight-line basis over the average future service of the active employees (plan participants) benefiting under the plan at the time of the amendment. The net actuarial 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 No. 87, "Employers' Accounting for Pensions" and SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions."

For the Year Ended December 31,	Pension Benefits 2005	Pension Benefits 2004	Pension Benefits 2003	Post-retirement Benefits 2005	Post-retirement Benefits 2004	Post-retirement Benefits 2003
	(Dollars in Thousands)					
Components of Net Periodic Cost:						
Service cost	$ 2,820	$ 2,572	$ 2,545	$ 238	$ 235	$ 218
Interest cost	3,730	3,295	2,928	384	356	289
Expected return on plan assets	(3,114)	(2,780)	(2,464)	—	—	—
Amortization of unrecognized:						
Transition obligation, net	57	57	57	58	58	58
Prior service costs	31	31	31	—	—	—
Actuarial loss, net	1,340	802	603	170	141	99
Net periodic cost	$ 4,864	$ 3,977	$ 3,700	$ 850	$ 790	$ 664
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost:						
Discount rate	6.00%	6.20%	6.75%	6.00%	6.10%	6.50%
Expected long-term return on plan assets	8.75%	9.00%	9.00%	N/A	N/A	N/A
Compensation rate increase	3.00%	3.20%	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 plans' 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.

For measurement purposes, the assumed annual health care cost growth rates were as follows.

	At December 31, 2005	At December 31, 2004
Health care cost trend rate assumed for next year	8.0%	8.5%
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	2012	2012

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

	One-Percentage-Point Increase	One-Percentage-Point Decrease
	(In Thousands)	
Effect on total of service and interest cost	$ 5	$ (5)
Effect on the present value of the accumulated projected benefit obligation	41	(41)

The asset allocation for the pension plans at the end of 2005 and 2004, and the target allocation for 2006, by asset category are as shown in the following table.

Asset Category	Target Allocations 2006	Plan Assets 2005	Plan Assets 2004
Pension Plans:			
Equity securities	65%	63%	65%
Debt securities	35%	27%	28%
Other	0%	10%	7%
Total		100%	100%

The Wolf Creek 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. Wolf Creek 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:				
2006	$ 6,000	$ 200	N/A	$ 300
Expected benefit payments:				
2006	$ (1,000)	$ (200)	N/A	$ (300)
2007	(1,200)	(200)	N/A	(300)
2008	(1,300)	(200)	N/A	(400)
2009	(1,600)	(200)	N/A	(400)
2010	(1,800)	(200)	N/A	(400)
2011 – 2015	(13,900)	(900)	N/A	(2,900)

Savings Plan

Wolf Creek maintains a qualified 401(k) savings plan in which most of its employees participate. They match employees' contributions in cash up to specified maximum limits. Wolf Creek'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 Wolf Creek's matching contributions was $0.9 million for 2005, $0.8 million for 2004 and $0.9 million for 2003.

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 $23.5 million at December 31, 2005, all of which has been committed. These commitments relate to purchase obligations issued and outstanding at year-end.

The yearly detail of the aggregate amount of required payments at December 31, 2005 was as follows.

	Committed Amount (In Thousands)
2006	$ 19,000
2007	4,525
2008	—
Thereafter	4
Total amount committed	$ 23,529

Clean Air Act

We must comply with the Clean Air Act, state laws and implementing regulations that impose, among other things, limitations on major pollutants, including sulfur dioxide (SO2), particulate matter and nitrogen oxides (NOx). In addition, we must comply with the provisions of the Clean Air Act Amendments of 1990 that require a two-phase reduction in some emissions. We have installed continuous monitoring and reporting equipment in order to meet the acid rain requirements.

Environmental Projects

KCPL began updating or installing additional equipment related to emissions controls at La Cygne unit 1 for which we incurred costs beginning in 2005. We will continue to incur costs through the completion of installation in 2009. We anticipate that our share of these costs will be approximately $105.0 million. Additionally, we have identified the potential for up to $225.0 million of expenditures at other power plants for other environmental projects during the next 8 years. This cost could increase depending on the resolution of the Environmental Protection Agency (EPA) New Source Review described below. In addition to the capital investment, were we to install such equipment, we anticipate that we would incur significant annual expense to operate and maintain the equipment and the operation of the equipment would reduce net production from our plants. As discussed above, the ECRR will allow for the timely inclusion in rates capital expenditures that are directly tied to environmental improvements required by the Clean Air Act. However, increased operating and maintenance costs can only be recovered through a change in our base rates following a rate review.

The degree to which we will need to reduce emissions and the timing of when such emissions control equipment may be required is uncertain. Both the timing and the nature of required investments depend on specific outcomes that result from interpretation of regulations, new regulations, legislation, and the resolution of the EPA New Source Review described below. Although we expect to recover such costs through our utility rates, we can provide no assurance that we would be able to fully and timely recover all or any increased costs relating to environmental compliance. Failure to recover these associated costs could have a material adverse effect on our consolidated financial condition or results of operations.

EPA New Source Review

Under Section 114(a) of the Clean Air Act (Section 114), the EPA is conducting investigations nationwide to determine whether modifications at coal-fired power plants are subject to New Source Review requirements or New Source Performance Standards. 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 in an attempt to reach a settlement. Westar Energy expects that any settlement with the EPA could require Westar Energy to update or install emissions controls at Jeffrey Energy Center over an agreed upon number of years. Additionally, Westar Energy might be required to update or install emissions controls at its other coal-fired plants, pay fines or penalties, or take other remedial action. Together, these costs could be material. The EPA informed Westar Energy that it has referred this matter to the Department of Justice (DOJ) for the DOJ to consider whether to pursue an enforcement action in federal district court. We believe that costs related to updating or installing emissions controls would qualify for recovery through the ECRR. If Westar Energy were to reach a settlement with the EPA, Westar Energy may be assessed a penalty. The penalty could be material and may not be recovered in rates. We anticipate that a portion of any of these potential costs would be allocated to us.

Manufactured Gas Sites

We have been associated with three former manufactured gas sites located in Kansas. We and the Kansas Department of Health and Environment entered into a consent agreement in 1994 governing all future work at these sites.

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 the 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 expiration of the license of the related nuclear power plant. Wolf Creek files a nuclear decommissioning and dismantlement study with the KCC every three years.

The KCC reviews nuclear decommissioning plans in two phases. Phase one is the approval of the nuclear decommissioning study, the current-year funding and future 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 of its pro rata share of the plant.

Wolf Creek filed an updated nuclear decommissioning site study with the KCC. Based on the 2005 site study of decommissioning costs, including the costs of decontamination, dismantling and site restoration, our share of such costs are estimated to be $243.3 million. This amount compares to the 2002 site study estimate for decommissioning costs of $220.0 million. The site study cost estimate represents the estimate to decommission Wolf Creek as of the site study year. The actual nuclear decommissioning costs may vary from the estimates because of changes in technology and changes in costs for labor, materials and equipment.

Electric rates charged to customers provide for recovery of these nuclear decommissioning costs over the life of Wolf Creek, which, as determined by the KCC for purposes of the funding schedule, will be through 2045. The NRC requires that funds to meet its nuclear decommissioning funding assurance requirement be in our nuclear decommissioning fund by the time our license expires in 2025. We believe that the KCC approved funding level will be sufficient to meet the NRC minimum financial assurance requirement. However, our consolidated results of operations would be materially adversely affected if we are not allowed to recover the full amount of the funding requirement.

Nuclear decommissioning costs that are recovered in rates are deposited in an external trust fund. In 2005, we expensed approximately $3.9 million for nuclear decommissioning. We record our investment in the nuclear decommissioning fund at fair value. The fair value approximated $100.8 million at December 31, 2005 and $91.1 million at December 31, 2004.

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 Wolf Creek 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 for the future disposal of spent nuclear fuel. Our share of the fee was $3.8 million in 2005, $4.3 million in 2004 and $3.8 million in 2003 and is calculated as one-tenth of a cent for each kilowatt-hour of net nuclear generation produced. We include these disposal costs in operating expenses.

In 2002, the Yucca Mountain site in Nevada was approved 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. Currently, the DOE has not defined a schedule for submitting a license application. The opening of the Yucca Mountain site has been delayed many times and could be delayed further due to litigation and other issues related to the site as a permanent repository for spent nuclear fuel. Wolf Creek has on-site temporary storage for spent nuclear fuel expected to be generated by Wolf Creek through the expiration of its operating license in 2025.

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. Both the nuclear liability and property insurance programs subscribed to by members of the nuclear power generating industry include industry aggregate limits for non-certified acts, as defined by the Terrorism Risk Insurance Act, of terrorism-related losses, including replacement power costs. An industry aggregate limit of $300.0 million exists for liability claims, regardless of the number of non-certified acts affecting Wolf Creek or any other nuclear energy liability policy or the number of policies in place. An industry aggregate limit of $3.24 billion plus any reinsurance recoverable by Nuclear Electric Insurance Limited (NEIL), our insurance provider, exists for property claims, including accidental outage power costs for acts of terrorism affecting Wolf Creek or any other nuclear energy facility property policy within twelve months from the date of the first act. These limits are the maximum amount to be paid to members who sustain losses or damages from these types of terrorist acts. For certified acts of terrorism, the individual policy limits apply. In addition, industry-wide retrospective assessment programs (discussed below) can apply once these insurance programs have been exhausted.

Nuclear Liability Insurance

Pursuant to the Price-Anderson Act, which was reauthorized through December 31, 2025 by the Energy Policy Act of 2005, we are required to insure against public liability claims resulting from nuclear incidents to the full limit of public liability, which is currently approximately $10.8 billion. This limit of liability consists of the maximum available commercial insurance of $300.0 million, and the remaining $10.5 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 $15.0 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, Congress could impose additional revenue-raising measures to pay claims.

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 $26.5 million (our share is $12.4 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, 2005, our share of Wolf Creek's nuclear fuel commitments were approximately $12.4 million for uranium concentrates expiring in 2007, $2.0 million for conversion expiring in 2007, $9.7 million for enrichment expiring at various times through 2006 and $54.1 million for fabrication through 2024. In addition, letters of intent have been issued with suppliers for major portions of Wolf Creek's future uranium, conversion and enrichment requirements extending through 2017.

At December 31, 2005, our coal and coal transportation contract commitments in 2005 dollars under the remaining terms of the contracts were $423.5 million. The largest contract expires in 2020, with the remaining contracts expiring at various times through 2013.

At December 31, 2005, our natural gas transportation commitments in 2005 dollars under the remaining terms of the contracts were $1.1 million. The natural gas transportation contracts provide firm service to several of our natural gas burning facilities and expire at various times through 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 Decommissioning Fund. Our portion of the assessment, including carrying costs, for Wolf Creek is approximately $9.7 million, adjusted for inflation. To date, we have paid approximately $9.0 million, with the estimated remainder payable over the next year. We recover such costs from prices we charge our customers.

14. ASSET RETIREMENT OBLIGATIONS

In accordance with SFAS No. 143, adopted January 2003, and FASB Interpretation No. 47, “Accounting for Conditional Asset Retirement Obligations” (FIN 47), adopted December 31, 2005, we have recognized legal obligations associated with the disposal 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.

Legal Liability

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 fair 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.

During 2005 we updated our nuclear decommissioning and dismantlement study. Based upon the results of the 2005 study, we have revised our estimate of our Wolf Creek asset retirement obligation. Accordingly, in 2005 we increased our asset retirement liability $14.6 million. Costs to retire Wolf Creek are currently being recovered through rates as provided by the KCC.

In addition, during 2005 we determined that we have conditional asset retirement obligations that are within the scope of FIN 47. The conditional asset retirement obligations include disposal of asbestos insulating material at our power plants, remediation of ash disposal ponds and the disposal of polychlorinated biphenyl (PCB) contaminated oil. As of December 31, 2005, we recorded an asset retirement obligation of approximately $14.7 million pursuant to the requirements of FIN 47 based on the fair value of these disposal obligations.

The amount of the retirement obligation related to asbestos disposal was recorded as of 1990, the date when the Environmental Protection Agency published the “National Emission Standards for Hazardous Air Pollutants: Asbestos NESHAP Revision; Final Rule.” We also capitalized the retirement obligation as an increase to the asset’s carrying value.

We operate, as permitted by the state of Kansas, ash landfills at several of our power plants. We have determined that the closure of these facilities represents a conditional asset retirement obligation as defined by FIN 47. Accordingly we have recognized an asset retirement obligation for the ash landfills. The liability was determined based upon the date each landfill was originally placed in service.

PCB contaminates are contained within company electrical equipment, primarily transformers. We have determined that the disposal of PCB-contaminated equipment represents a conditional asset retirement obligation as defined by FIN 47. Accordingly, we have recognized an asset retirement obligation for the PCB-contaminated equipment. The liability was determined based upon the PCB regulations that originally became effective in 1978.

The following table summarizes our legal asset retirement obligations included on our consolidated balance sheets in long-term liabilities.

	As of December 31, 2005	2004	2003
	(In Thousands)		
Beginning asset retirement obligation	$ 87,118	$80,695	$ —
Transition liability	3,803	—	74,745
Accretion expense	17,853	6,423	5,950
Additional estimated liability	14,638	—	—
Ending asset retirement obligation	$123,412	$87,118	$80,695

Cumulative Effect of FIN 47: In March 2005, the FASB issued FIN 47. The interpretation clarified the term "conditional asset retirement obligation" as used in SFAS No. 143. The recording of the obligation for regulated operations has no income statement impact due to the deferral of the adjustments through the establishment of a regulatory asset pursuant to SFAS No. 71. If we had implemented FIN 47 at January 1, 2004, the liability for asset retirement obligations would have been $13.3 million. The liability at December 31, 2004 would have been $14.0 million. The following table summarizes the accounting for the initial adoption of FIN 47, as of December 31, 2005.

	Plant Assets	Regulatory Assets	Long-Term Liabilities
		(In Thousands)	
Reflect retirement obligation when liability incurred	$ 3,803	$ —	$ 3,803
Record accretion of liability to adoption date	—	10,918	10,918
Record depreciation of plant to adoption date	(2,380)	2,380	—
Net impact of FIN 47	$ 1,423	$ 13,298	$14,721

Non-Legal Liability – Cost of Removal

We recover in rates, as a component of depreciation, the costs to dispose of utility plant assets that do not represent legal retirement obligations. We had $6.9 million in amounts collected, but unspent, for removal costs classified as a regulatory liability at December 31, 2005 and $2.6 million at December 31, 2004. The net amount related to non-legal retirement costs can fluctuate based on amounts recovered in rates compared to removal costs incurred.

15. LEGAL PROCEEDINGS

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 results of operations. See also Notes 3, 13, and 16 for discussion of KCC regulatory proceedings, alleged violations of the Clean Air Act and an investigation by FERC.

16. FERC INVESTIGATION

On May 19, 2005, Westar Energy and FERC reached a settlement regarding the matters related to the FERC investigation of power trades with Cleco Corporation and its affiliates, power transactions between our system and our marketing operations and power trades in which we or other trading companies acted as intermediaries. The settlement does not require Westar Energy or us to make any monetary payments. As part of the settlement, Westar Energy and we will follow a three-year plan to ensure compliance with FERC rules. The settlement was neither a finding of wrongdoing by FERC nor an admission of wrongdoing by us or Westar Energy.

17. OPERATING LEASES

We lease office buildings, computer equipment, vehicles, rail cars, a generating facility and other property and equipment. These leases have various terms and expiration dates ranging from 1 to 24 years.

In determining lease expense, we recognize the effects of scheduled rent increases on a straight-line basis over the minimum lease term. The rental expense associated with the La Cygne unit 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 La Cygne unit 2 lease and other operating leases.

Year Ended December 31,	La Cygne Unit 2 Lease (a)	Total Operating Leases
	(In Thousands)	
Rental expense:		
2003	$ 28,895	$ 34,199
2004	28,895	32,071
2005	23,481	26,833
Future commitments:		
2006	$ 33,535	$ 36,731
2007	23,464	25,668
2008	32,892	35,139
2009	32,964	35,043
2010	33,041	35,127
Thereafter	355,805	370,102
Total future commitments	$ 511,701	$537,810

(a) The La Cygne unit 2 lease amounts are included in the total operating leases column.

On June 30, 2005, we and the owner of La Cygne unit 2 amended certain terms of the agreement relating to our lease of La Cygne unit 2, including an extension of the lease term. The lease was entered into in 1987 with an initial term ending in September 2016. With the June 30, 2005 extension, the term of the lease will expire in September 2029. Upon expiration of the lease term in 2029, we have a fixed price option to purchase La Cygne unit 2 for a price that is estimated to be the fair market value of the facility in 2029. We can also elect to renew the lease at the expiration of the lease term in 2029. However, any renewal period, when added to the initial lease term, cannot exceed 80% of the estimated useful life of La Cygne unit 2.

On June 30, 2005, we caused the owner of La Cygne unit 2 to refinance the debt used by the owner to finance the purchase of the facility. The savings resulting from extending the term of the lease and refinancing the debt will reduce our annual lease expense by approximately $10.8 million.

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. The net amount payable to affiliates was approximately $154.6 million at December 31, 2005 and $91.5 million at December 31, 2004 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 $20.0 million to Westar Energy for the year ended December 31, 2005, $75.0 million for the year ended December 31, 2004 and $100.0 million for the year ended December 31, 2003.

Termination of Shared Services Agreement

Westar Energy previously maintained shared services agreements with ONEOK, Inc. pursuant to which Westar Energy and ONEOK provided customer service functions to each other, including meter reading, customer billing and call center operations. ONEOK terminated portions of this shared services agreement in September 2004, including electric service orders, call center functions, bill processing and remittance processing. In addition to joint meter reading, Westar Energy and ONEOK continue to share some facilities and a mobile communications system.

19. QUARTERLY RESULTS (UNAUDITED)

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)			
2005				
Sales	$165,770	$181,009	$229,058	$195,849
Income from operations	12,716	22,804	47,203	41,162
Net income	5,613	22,869	36,543	20,553
2004				
Sales	$162,091	$180,335	$202,209	$170,304
Income from operations	11,591	42,970	50,445	32,367
Net income	2,945	26,923	33,948	17,412

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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, 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, at December 31, 2005, 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 the fourth quarter ended December 31, 2005, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

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.

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ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Independent Registered Public Accounting Firm 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 services provided for fiscal years ended December 31, 2005 and 2004 are as follows.

	2005	2004
Audit fees	$371,410	$365,762

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 registered public accounting firm 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 AND FINANCIAL STATEMENT SCHEDULES

FINANCIAL STATEMENTS INCLUDED HEREIN

Kansas Gas and Electric Company

SCHEDULES

Schedules omitted as not applicable or not required under the Rules of Regulation S-X: I, III, IV, and V

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 15(a)(3) of Form 10-K. All exhibits marked "#" are filed with this Form 10-K.

	Description	
3(a)	-Articles of Incorporation (Filed as Exhibit 3(a) to the Form 10-K for the period ended December 31, 1992, File No. 1-7324, filed March 30, 1993)	I
3(b)	-Certificate of Merger of Kansas Gas and Electric Company into KCA Corporation (Filed as Exhibit 3(b) to the Form 10-K for the period ended December 31, 1992, File No. 1-7324, filed March 30, 1993)	I
3(c)	-By-laws as amended (Filed as Exhibit 3(c) to the Form 10-K for the period ended December 31, 1992, File No. 1-7324, filed March 30, 1993)	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-three 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 the 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 the 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 the 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 the Form 10-K for December 31, 1989, File No. 1-7324; Exhibits 4(c)2 and 4(c)3 to the Form 10-K for December 31, 1992, File No. 1-7324; Exhibit 4(b) to the Form S-3, File No. 33-50075; Exhibits 4(c)2 and 4(c)3 to the Form 10-K for December 31, 1993, File No. 1-7324; Exhibit 4(c)2 to the Form 10-K for December 31, 1994, File No. 1-7324); Exhibit 4.1 to the June 30, 2002 Form 10-Q	I
4(d)	-Second Supplemental Indenture, dated as of June 30, 2005, to the Trust Indenture, Security Agreement and Mortgage dated as of September 1, 2987, as supplemented by the First Supplemental Indenture dated as of September 29, 1992, among U.S. Bank National Association (as successor in interest to The Connecticut National Bank), a national banking association (not in its individual capacity except to the extent set forth therein but solely as owner trustee under the Trust Agreement dated as of September 1, 1987, as supplemented, between Comcast MO Financial Services, Inc. (formerly named U S West Financial Services, Inc.) as Owner Participant and U.S. Bank National Association (as successor in interest to The Connecticut National Bank) as Owner Trustee), Kansas Gas and Electric Company and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company), a New York banking corporation, as trustee (filed as Exhibit 4.2 to the Form 8-K filed on July 1, 2005)	I
4(e)	-Forty-Second Supplemental Indenture dated March 12, 2004 between Kansas Gas and Electric Company and BNY Midwest Trust Company, as Trustee (filed as an Exhibit 4(d) to the Form 10-K for the period ended December 31, 2004 filed on March 16, 2005)	I

4(f)	-Forty-Third Supplemental Indenture dated June 1, 2004 between Kansas Gas and Electric Company and BNY Midwest Trust Company, as Trustee (filed as an Exhibit 4(e) to the Form 10-K for the period ended December 31, 2004 filed on March 16, 2005)	I
4(g)	-Forty-Fourth Supplemental Indenture dated May 6, 2005 between Kansas Gas and Electric Company and BNY Midwest Trust Company, as Trustee (filed as Exhibit 4 to the Form 10-Q for the period ended March 31, 2005 filed on May 10, 2005)	I
4(h)	-Registration Rights Agreement among Kansas Gas and Electric Company, a Kansas corporation, U.S. Bank National Association, a national banking association, not in its individual capacity but solely as owner trustee, and Credit Suisse First Boston LLC, as Representative of the Several Purchasers, dated June 30, 2005 (filed as Exhibit 4.1 to the Form 8-K filed on July 1, 2005)	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)	-La Cygne Unit 2 Lease (filed as Exhibit 10(a) to the Form 10-K for the period ended December 31, 1988, File No. 1-7324, filed on March 2, 1989)	I
10(b)	-Amendment No. 1 to the Sublease, dated June 30, 2005, between U.S. Bank National Association (as successor in interest to The Connecticut National Bank), a national banking association, not in its individual capacity but solely as owner trustee under the Trust Agreement with Comcast MO Financial Services, Inc. (formerly named US West Financial Services, Inc.) dated as of September 1, 1987 as sublessor, and Kansas Gas and Electric Company, as sublessee, to the Sublease dated as of September 1, 1987 between the Sublessor and the Sublessee (filed as Exhibit 10.1 to the Form 8-K filed on July 1, 2005)	I
10(c)	-Amendment No. 1 to Ground Lease, dated June 30, 2005, between Kansas Gas and Electric Company, as lessor, and U.S. Bank National Association (as successor in interest to The Connecticut National Bank), a national banking association, not in its individual capacity but solely as owner trustee under the Trust Agreement with Comcast MO Financial Services, Inc. (formerly named US West Financial Services, Inc.) dated as of September 1, 1987, as lessee (this “Amendment”) to the Ground Lease dated as of September 1, 1987 between the lessor and the lessee (filed as Exhibit 10.2 to the Form 8-K filed on July 1, 2005)	I
10(d)	-Amendment No. 3 to La Cygne Unit 2 Lease Agreement dated as of September 29, 1992 (filed as Exhibit 10(b)1 to the Form 10-K for the period ended December 31, 1992, File No. 1-7324, filed on March 30, 1993)	I
10(e)	-Amendment No. 4 to Lease Agreement, dated June 30, 2005, between U.S. Bank National Association (as successor in interest to The Connecticut National Bank), a national banking association, not in its individual capacity but solely as owner trustee under a Trust Agreement, dated as of September 1, 1987, between Comcast MO Financial Services, Inc., (formerly named US West Financial Services, Inc.), a Colorado corporation, and Owner Trustee, as lessor, and Kansas Gas and Electric Company, a Kansas corporation, as lessee (filed as Exhibit 10.3 to the Form 8-K filed on July 1, 2005)	I
10(f)	-Second Supplemental Participation Agreement, dated June 30, 2005, among U.S. Bank National Association (as successor in interest to The Connecticut National Bank), a national banking association, not in its individual capacity except to the extent set forth herein but solely as owner trustee under the Trust Agreement dated as of September 1, 1987, Deutsche Bank Trust Company Americas (as successor in interest to Bankers Trust Company), a New York banking corporation, in its individual capacity to the extent set forth therein and as indenture trustee, Comcast MO Financial Services, Inc. (formerly named US West Financial Services, Inc.), a Colorado corporation, as owner participant, and Kansas Gas and Electric Company, a Kansas corporation, as lessee (filed as Exhibit 10.4 to the Form 8-K filed on July 1, 2005)	I
10(g)	-Outside Directors’ Deferred Compensation Plan (filed as Exhibit 10(c) to the Form 10-K for the period ended December 31, 1993, File No. 1-7324, filed on March 18, 1994)*	I
12	-Computations of Ratio of Consolidated Earnings to Fixed Charges	#

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31(a)	-Certification of Principal Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	#
31(b)	-Certification of Principal Accounting Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	#
32	-Certifications pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (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 the Form 10-Q for the period ended June 30, 2001 filed on August 14, 2001)	I
99(b)	-Kansas Corporation Commission Order dated November 8, 2002 (filed as Exhibit 99.2 to the Form 10-Q for the period ended September 30, 2002 filed on November 15, 2002)	I
99(c)	-Kansas Corporation Commission Order dated December 23, 2002 (filed as Exhibit 99(f) to the Form 10-K for the period ended December 31, 2002 filed on April 15, 2003)	I
99(d)	-Debt Reduction Plan filed with the Kansas Corporation Commission on February 6, 2003 (filed as Exhibit 99(g) to the Form 10-K for the period ended December 31, 2002 filed on April 15, 2003)	I
99(e)	-Kansas Corporation Commission Order dated February 10, 2003 (filed as Exhibit 99(h) to the Form 10-K for the period ended December 31, 2002 filed on April 15, 2003)	I
99(f)	-Kansas Corporation Commission Order dated March 11, 2003 (filed as Exhibit 99(i) to the Form 10-K for the period ended December 31, 2002 filed on April 15, 2003)	I
99(g)	-Summary of Rate Application dated May 2, 2005 (filed as Exhibit 99.1 to the Form 8-KA filed on May 10, 2005)	I

KANSAS GAS AND ELECTRIC COMPANY
SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS

Description	Balance at Beginning of Period	Charged to Costs and Expenses	Deductions (a)	Balance at End of Period
	(In Thousands)			
Year ended December 31, 2003				
Allowances deducted from assets for doubtful accounts	$ 6,160	$ 3,807	$ (4,564)	$ 5,403
Year ended December 31, 2004				
Allowances deducted from assets for doubtful accounts	$ 5,403	$ 2,581	$ (2,776)	$ 5,208
Year ended December 31, 2005				
Allowances deducted from assets for doubtful accounts	$ 5,208	$ 3,739	$ (3,954)	$ 4,993

(a) Deductions are primarily the result of write-offs of accounts receivable.

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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 13, 2006

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 13, 2006
/s/ Mark A. Ruelle (Mark A. Ruelle)	Vice President and Treasurer (Principal Financial and Accounting Officer)	March 13, 2006
/s/ Douglas R. Sterbenz (Douglas R. Sterbenz)	Director	March 13, 2006
/s/ Caroline A. Williams (Caroline A. Williams)	Director	March 13, 2006

Exhibit 12

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

	Year Ended December 31,				
	2005	2004	2003	2002	2001
Earnings from continuing operations (a)	$ 118,313	$ 115,786	$ 93,630	$ 75,618	$ 35,701
Fixed Charges:					
Interest expense	29,874	33,171	55,467	47,844	49,610
Interest on corporate-owned life insurance borrowings	46,431	45,396	47,245	46,853	44,063
Interest applicable to rentals	20,234	18,270	19,688	20,766	22,822
Total Fixed Charges	96,539	96,837	122,400	115,463	116,495
Earnings (a)	$ 214,852	$ 212,623	$ 216,030	$ 191,081	$ 152,196
Ratio of Earnings to Fixed Charges	2.23	2.20	1.76	1.65	1.31

(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 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, certify that:

1. I have reviewed this annual report on Form 10-K for the period ended December 31, 2005 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. Evaluated the effectiveness of the registrant’s disclosure controls and procedures as of a date within 90 days prior to the filing date of this report (the “Evaluation Date”); and
    c. Presented in this report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;
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 13, 2006

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, certify that:

1. I have reviewed this annual report on Form 10-K for the period ended December 31, 2006 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. Evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this report (the "Evaluation Date"); and

    c. Presented in this report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

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 13, 2006

By: /s/ Mark A. Ruelle
Mark A. Ruelle,
Vice President and Treasurer
(Principal Financial and Accounting Officer)

Exhibit 32

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, 2005 (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 13, 2006	By:	/s/ William B. Moore
		William B. Moore, Chairman of the Board and President (Principal Executive Officer)
Date: March 13, 2006	By:	/s/ Mark A. Ruelle
		Mark A. Ruelle, Vice President and Treasurer (Principal Financial and Accounting Officer)