WOLF CREEK
NUCLEAR OPERATING CORPORATION

Kevin J. Moles
Manager Regulatory Affairs

May 18, 2005

RA 05-0060

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555-0001

Subject: Docket No. 50-482: Transmittal of 2004 Annual Financial Reports

Gentlemen:

Wolf Creek Nuclear Operating Corporation is transmitting one copy each of the 2004 annual reports, including financial statements for its owners: Kansas Gas and Electric Company (KGE), a wholly-owned subsidiary of Westar Energy, Inc., Kansas City Power & Light Company (KCPL), a wholly-owned subsidiary of Great Plains Energy Incorporated, and Kansas Electric Power Cooperative, Inc. (KEPCo). This information is being submitted in accordance with 10 CFR 50.71(b).

If you have any questions concerning this matter, please contact me at (620) 364-4126, or Diane Hooper at (620) 364-4041.

Very truly yours,

Kevin J. Moles

Kevin J. Moles

KJM/rlg

Enclosures (3)

cc: J. N. Donohew (NRC), w/e
D. N. Graves (NRC), w/e
B. S. Mallett (NRC), w/e
Senior Resident Inspector (NRC), w/e

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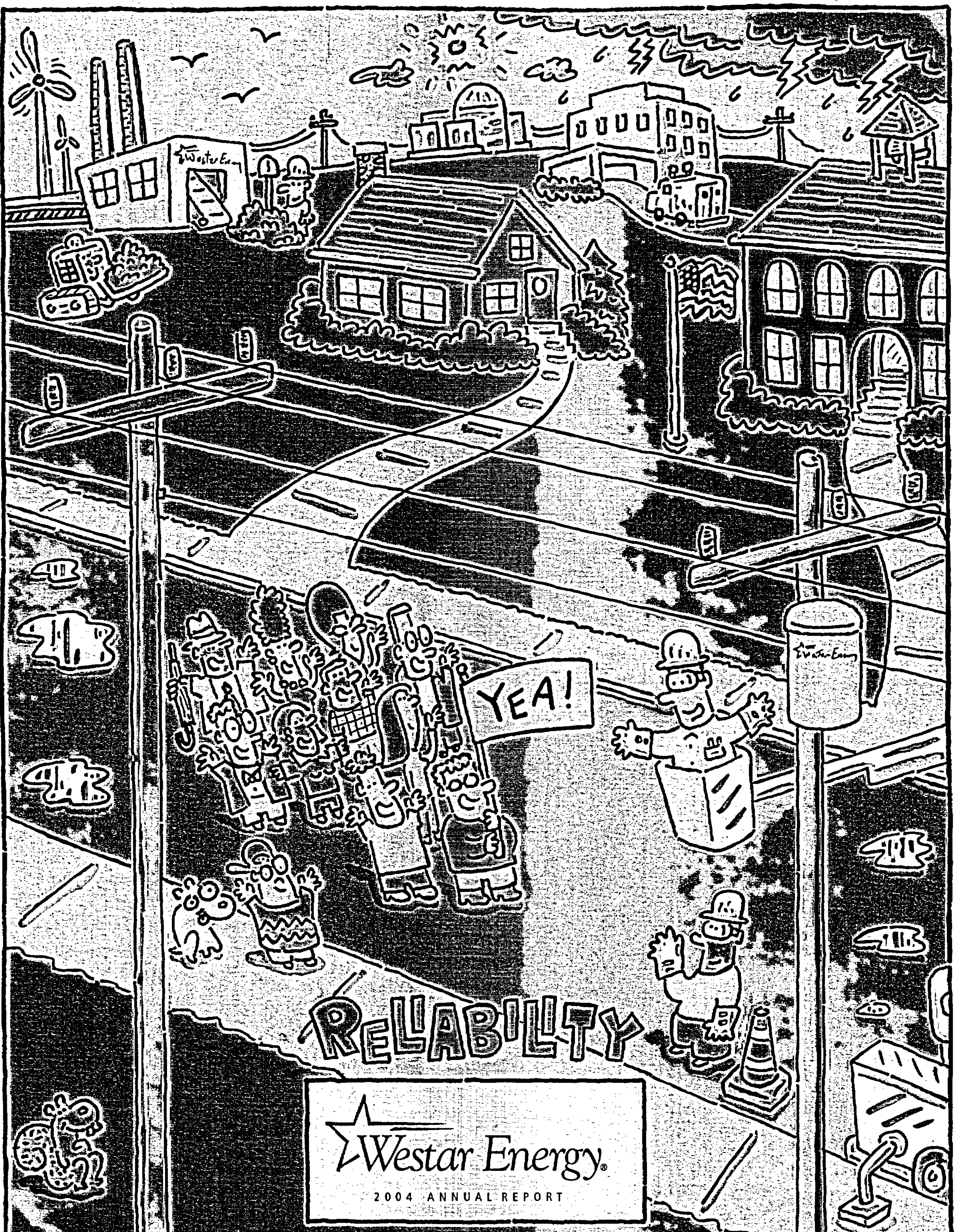
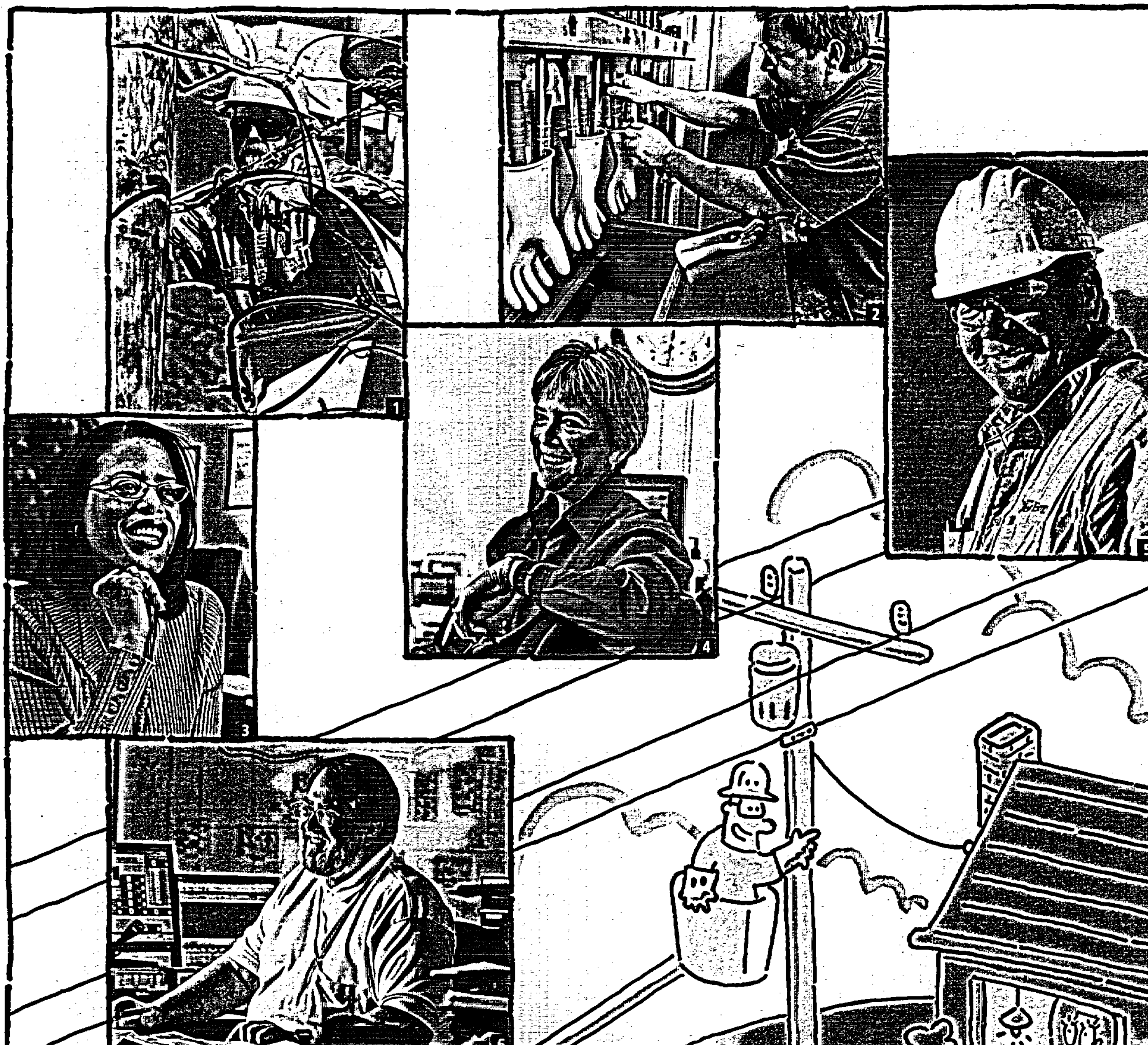
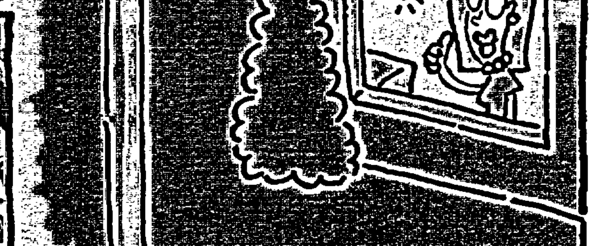

YEA!
RELIABILITY
Westar Energy
2004 ANNUAL REPORT





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1. Doug Simrell, troubleshooter, completes a pole replacement after the January 2005 ice storm in Wichita. **2.** Employees like Simrell depend on Larry Heinrich, live line equipment tester, to ensure that rubber gloves they use when working on energized equipment are without defect. **3.** Patrice Poole, human resources clerk, assists Wichita employees. **4.** Suzanne Coin, community support representative, is a community liaison for Westar Energy. **5.** Tom Homewood, cable splicer, journeyman, helps provide reliable power to Wichita customers. **6.** Dale Renner, service operator, directs crews to their next assignment. **7.** Kyle Hazelwood, cable splicer apprentice, left, works under the watchful eye of Terry Fleming, cable foreman.

DEAR FELLOW SHAREHOLDER:

Here, in summary, are highlights of what Westar Energy accomplished in 2004.

In February we closed the sale of Protection One and thereby fulfilled our pledge to return Westar to a pure electric utility. Through early calls and timely retirements, we reduced utility debt by $533 million — on top of the $966 million by which we reduced debt in 2003. These debt reductions combined with the issue of 12.1 million shares of new equity last spring, brought our balance sheet to 45% equity, from less than 30% in 2002. Those debt reductions, combined with the refinancing of $900 million of our remaining $1.7 billion of debt, have reduced our annual interest expense by more than $110 million. Our first mortgage bonds are once again rated investment grade by the three rating services that follow us.

In December our board increased the common dividend to an indicated annual level of 92 cents from 76 cents. We expect to review the dividend again in early 2006. The year end closing price for our common shares was $22.87, a $2.62 gain over the 2003 year end close of $20.25. The total return to Westar shareholders in 2004 was 17.4%. For 2003 and 2004 together, the total return was 152%.

Although summer weather was 16% cooler than average, we achieved financial results in line with our announced earnings guidance.

It is discouraging when our equipment doesn't operate the way we wish it would, as was the case last January when the generator rotor at one of our Jeffrey Energy Center coal units failed. But it was encouraging to see our employees working brilliantly to get the unit back on-line in just 23 days, cutting the expected downtime virtually in half. Work like that enabled us to meet our targeted margins for wholesale sales.

We exceeded our goals for transmission and distribution system reliability. The average number of outages per customer was 1.47 versus our goal of 1.70. And the average length of an outage was 139 minutes versus our goal of 162 minutes. We improved customer service in other important ways as well. In our call center we achieved an answered call rate above 95%, including times when tens of thousands of our customers were without power due to severe storms.

Safety is first among our three core values. In 2004 we set new standards for industrial safety as measured by the number of injuries requiring medical attention per 100 employees (OSHA incident rate). The OSHA rate of 1.55 in our power plants was the lowest that it has ever been. That rate compares with an industry average for power plants of 4.15. In our transmission and distribution operations, our OSHA rate was 2.78. It was 5.32 in 2003. The industry average is 5.17.

An important focus in the last two years has been compliance with the letter and spirit of the Sarbanes-Oxley Act of 2002 regarding corporate governance, financial disclosure, and internal controls. Elsewhere in this report we hope you note that Messrs. Haines and Ruelle (our CFO) have attested to the effectiveness of our internal controls.

Our employees and retirees continue to be leaders in their communities. Employees increased their annual contributions to the United Way by 20%. Employees and retirees volunteered over 83,000 hours of community service in 2004, a 15% increase over 2003. Through our School Connections program, our active and retired employees volunteer in many schools throughout our service area. Our employees collected more than 83,000 pounds of food to replenish the shelves of food banks in eastern Kansas.

Our Green Team completed 57 conservation projects in 2004. Notably, the Green Team has committed to provide 5,000 volunteer hours for improvement projects at the Tallgrass Prairie National Preserve.

Looking forward, as the last step in the restructuring plan approved by the Kansas Corporation Commission in July 2003, we will go through a review of our rates in 2005. Our operating and financial results for 2004 will serve as the basis for the review, which we expect to conclude by year end. We welcome this review and see it as an opportunity to make sure our rates are fair and logical and to demonstrate that we are doing a good job for our customers. On average, our rates are the lowest in Kansas and are 18% to 26% below the national average.

We continue to deal with investigation and litigation related to matters discussed at length in the Report of the Special Committee to the Board of Directors, released in May 2003. Those matters are discussed in our 2004 Form 10-K that is incorporated in this report.

In January 2005 eastern Kansas was hit with the most destructive ice storm in Westar's history. More than 260,000 of our customers lost power in that storm, many more than once. Our employees, with help from contractors and other utility companies from across the nation, worked safely and indefatigably for 10 days on the restoration effort. This storm was a severe test of our resolve to be focused on customer service. *The Wichita Eagle* had this to say about our effort:

> *"Westar Energy utility workers, city tree trimmers and others who worked tirelessly to restore power and street access to thousands of Wichitans after the recent ice storm deserve a hearty thanks from this community."*

Finally, we are very pleased to report that in September, Dr. Jerry Farley, President of Washburn University, and Ms. Sandra Lawrence, Vice President of Midwest Research Institute, joined our board. Their skills, experience, and insight have added more depth and balance to our board and will be of substantial benefit to the company.

We appreciate your confidence.

Sincerely,

Charles Q. Chandler IV
Chairman of the Board

James S. Haines, Jr.
President & CEO

Blurring the Lines Between Power Plants and Service Reliability

Fuel for Thought in a New Energy Era

By James Haines

The electric power industry nearly always has measured service reliability not by the operation of the power plants that make electricity, but by the performance of the towers, poles, lines, transformers, and associated equipment and facilities that deliver it — the wires. When the wires have succumbed to the stress of constant use, severe weather, vehicles, squirrels and birds, tree limbs, vandals, and errant construction digging, power plants have continued to operate. Indeed, when we flip a switch, if we even think about electric service reliability, we think of the wires — we think of bucket trucks and linemen climbing poles.

In coming years, however, flipping a switch may make us pause to wonder if the wind is blowing, the sun is shining, there is gas in the pipeline, or the limit for emissions from the coal plants has been exceeded. *We face the prospect that electric service reliability will become more vulnerable to power plant availability than failures in the wires.* That would be a dire outcome — while recovery from a wires failure takes hours or days, recovery from problems that could affect power plant availability, e.g. fuel supply or environmental constraints or insufficient capital, could take years. Fortunately, we can greatly reduce, if not eliminate, this danger through sound energy policies and prudent management.

A few national and Westar Energy specific facts help frame discussion of this issue:

- Based on current consumption, extraction technology, and economics, U.S. domestic supplies of coal and uranium will last for centuries, while supplies of natural gas are declining precipitously.
- Since 1990, about 85% of new power plants have been fueled by natural gas, 5% by coal.
- No new nuclear power plants have been ordered for construction in the U.S. since 1978. None ordered after 1973 were completed.
- In 2003, fossil fueled power plants accounted for 11% of all carbon monoxide, nitrogen oxide, sulphur dioxide, volatile organic compounds, and particulate emissions from U.S. sources; motor vehicles accounted for 48%.
- Since 1980, power plant emissions have declined by about 35%.
- Air pollution emissions from U.S. nuclear power plants: none.
- More than 95% of the electricity that Westar generated in 2004 came from its coal and uranium fueled plants.
- The MW weighted average age of those plants has increased from just over eight years in 1985 to just over 27 years in 2004.
- Expected availability on demand from a coal plant: almost 90%; from a wind turbine: when the wind blows.

A Transition Between Two Energy Eras

I believe we are in a transition between two energy eras. The first, which covered roughly the 20th century, was characterized by abundant and ever cheaper energy — especially electricity. During that era, electricity became the energy form of choice. Demand doubled every 10 years until the early '70's. In the last 25 years of that era, several factors signaled its end.

The oil embargoes of the '70's showed the vulnerability of the U.S. economy to dependence upon foreign energy resources. Resulting increases in energy prices contributed to a stagnant economy and rampant inflation — stagflation. Annual electric demand growth slowed to 2% from 7%. The electric industry and its regulators were unable to cope with the financial consequences of such slower growth. Electric utility credit quality slipped from an average of AA- to BBB. There was growing recognition that burning fossil fuels, e.g. to make electricity and power vehicles, can harm the environment. Virtually unknown in 1975, concerns about "global warming" and "greenhouse gases" dominated energy policy debate by 2000.

Electricity price increases in the '70's and early '80's, as well as projected supply shortages in the '90's, led many to conclude that regulated retail monopoly markets for electricity were grossly inefficient and that *a shift to competition would assure renewed abundance and lower prices.* The last gasp of the former era was a series of experiments with competitive retail electricity markets in the late '90's with results that ranged from lackluster to colossal failure.

Natural gas fueled the enthusiasm for retail competition. Significantly more efficient gas plant technology came to the fore in the '90's. Additionally, gas fueled plants were easy to permit, fast to build, and relatively cheap. They were believed to have a significantly shorter and therefore a more certain payback. Gas also is substantially cleaner than coal so environmental concerns were greatly reduced. Accordingly, virtually all of the unregulated power plants built in the '90's were fueled with natural gas. With subsequent sharp increases in the cost of gas, many of those plants are now underutilized.

It is a subtle irony that developers of unregulated plants relied on natural gas, a relatively scarce resource, over coal, our most abundant energy resource. Coal fueled plants, of course, require much more capital up front, are more difficult to site and permit, take longer to build, and are subject to increasingly more stringent and costly environmental controls. It appears that the success of competitive retail electricity markets depended upon a very thin reed: cheap gas.

The emergence of the Chinese economy punctuated the close of the former era. From 1990 through 2004, China's GDP averaged year over year growth above 9%. From 1900 to 1950, as the U.S. economy modernized and its population doubled to 152 million, its energy use *quadrupled.* Imagine the growing energy needs of over 1 billion people in an economy going through a similar metamorphosis. Add to that the energy needs of other developing nations. And add to that the energy needed to sustain growth in developed economies in the U.S., Japan, and Western Europe. Finally, add the need to protect global environmental quality.

All the above factors point to increasing pressure not on the wires that distribute electricity but on the plants and fuel necessary to produce it.

Characteristics of the New Era

In the new era, policy makers will finally recognize that *it is better to embrace and perfect the use of virtually unlimited and reliable energy resources under our control than to fight about relatively limited energy resources under the control of others.* In the new era, routine use of the most dear fuels — natural gas and oil — to make electricity will sharply decline. Ultimately these fuels will be used sparingly to generate electricity — only in peak and emergency conditions.

Developing economies will compete more vigorously for their share of the Earth's resources, seeking to reduce barriers to their own development and perhaps erecting barriers for others. For all economies, but especially developed ones, *energy independence will become increasingly important.* The difficulty of this for the U.S. cannot be overstated. At 20 million barrels per day, the U.S. consumes approximately four times more oil than it produces.

As harm to the environment from using fossil fuels becomes more definable, energy policy will center more and more on environmental concerns. Our most abundant domestic energy resource, coal, presents significant environmental challenges. Technologies under development, however, promise to dramatically lower emissions from coal fueled power plants and existing coal plants can be modified to greatly reduce their emissions. These improvements, though, will substantially increase the cost of coal-generated electricity. We can moderate the increased use of coal only if, once again, we embrace nuclear power — itself with high upfront capital costs and its own set of political and environmental concerns. To help overcome uncertainty and achieve energy independence, our national energy policy must rely on both fuels.

With the rise of global terrorism, the security of our energy infrastructure will become as important as environmental protection. That will simply underscore the importance of energy independence.

Supplies of coal and uranium will remain abundant, but the cost of converting them to electricity without unacceptable risk to the environment will be substantial. While existing coal plants will require costly upgrades to comply with more stringent environmental regulations, those upgrades will be significantly less expensive than replacement with new plants. Existing nuclear plants also have attractive opportunities for life extension. Consequently, customers of utilities with substantial existing coal and uranium fueled plants will be advantaged in the new era.

Increased uranium use will require the political resolve to develop a permanent facility for disposing of highly radioactive nuclear waste. The prospects for this, however, are not good. After collecting $20 billion to develop a permanent storage facility for highly radioactive waste from nuclear power plants, the Department of Energy has failed to do so.

Certainly, as the price of electricity increases, more substitutes for electricity will become viable and improved efficiency in the use of electricity will become more important. Substantial research and development will be devoted to alternative and renewable forms of electricity generation. While these forms will reduce some dependence on coal and uranium, they will not eliminate the need for plants that provide electricity on demand. Our growing reliance on digital technology will only increase the importance of continuous and reliable supplies of electricity. *It won't do for utilities to tell customers that power is not available because the wind has died or the sun is behind a cloud.*

Finding Light at the End of the Transition

The most important issue for the electric power industry in the U.S. is regulatory certainty, according to a 2004 survey of industry leaders. This is not surprising. Concern for certainty is likely highest during transition periods when established practices and rules are in flux. This is especially so in the electric industry, which is not only capital intensive but also is required to put its capital at risk in cycles of 50 years or more.

If the transition is mishandled, electric service outages will become a way of life. To failures in the wires as causes of outages, we will add shortages of natural gas and oil, environmental alerts, terrorist attacks, and insufficient capital. And to the extent the U.S. remains dependent on foreign energy resources, a U.S. presence and influence will remain necessary in areas that historically have been politically volatile.

If the transition is well handled, hallmarks of the new energy era will be *further* dramatic reductions in harmful emissions from power plants, increased reliance on coal and renewed use of uranium, sparing use of natural gas and oil, emergence of alternative electricity generation technologies as significant sources — and higher prices. Higher prices will mean greater emphasis on conservation and efficiency, including capital investment that promises to reduce fuel use.

How Will Westar Energy Fare?

How will Westar Energy fare in the new energy era? Well, we believe. Consider:

1. Without distraction, we will be focused on satisfying the electric energy needs of our customers. As we committed to do two years ago, we have returned to being a pure utility. We have reduced debt by nearly $2 billion and significantly improved our financial stability. Our financial obligations and structure are now consistent with our public service obligation.
2. We have an ideal mix of generation facilities. Although we have the capability to generate substantial electricity with natural gas and oil, for normal operation almost all of our electricity is made with coal or uranium.
3. Our coal supplies are very low in sulfur content.
4. Kansas policy makers appropriately considered and rejected a change to retail competition. As a result, Westar remains an integrated company. Our business strategy is matched with our public service obligation, and both are well matched with our resources.
5. Finally, the Kansas Legislature, through recently enacted legislation, has created a more favorable environment in Kansas for constructing generation and transmission facilities. Among other things, this legislation greatly simplifies and streamlines the process for siting transmission lines. Other recent legislation requires the Kansas Corporation Commission, *prior* to the start of construction, to make binding determinations of the rate treatment of very long-lived transmission and generation facilities and permits it to include in rates the value of generating facilities while under construction.

The "Weather" Will Be Stormy

While the above factors show Westar well suited to successfully complete this transition, at times the political and regulatory "weather" will be stormy. These storms will be severe if policy makers in the new era rely on the regulatory paradigm of the former era.

In the new era, new facilities will need to be built. Perhaps less obvious, but of greater consequence for companies like Westar, existing facilities will need mid or even late life "makeovers" to satisfy more rigorous environmental standards and extend their useful lives. Both will require substantial amounts of capital. Uncertainty makes investors cautious at best; at worst they invest elsewhere.

Why might investors be cautious? Consider their experience in the last 25 years of the former era. At the beginning of that period, warnings of natural gas shortages culminated in policy makers passing the Fuel Use Act in 1978 that required utilities to phase out the use of natural gas in power plants. In response, many utilities launched massive construction programs to replace gas fueled plants with those using coal and uranium. And then, through so-called prudence reviews, when those facilities began operation they were judged to be unneeded and to have been imprudently managed. As a result, billions of dollars of investment in those new facilities were disallowed.

Yet virtually all of those facilities are in service today and without them the U.S. economy would be in shambles for want of affordable and adequate supplies of electricity.

Then in the '90's, in response to the siren song of competitive markets (i.e. lower prices for consumers and high profits for entrepreneurs), massive amounts of capital were invested in unregulated natural gas fueled plants. Ephemeral though it was, natural gas prices were so low and foresight so blinded that construction of new coal plants came to a virtual standstill and some coal and nuclear plants were sold at deeply discounted prices. But, as gas became dear, many gas plants were cancelled and of the ones that were completed few have met the expectations of their initial investors.

There is at least one important lesson in the failed attempts by regulators, through prudence reviews and other expedients, and by legislators, through "experiments" with retail competition, to keep prices low in the short run. Eventually customers must pay the real costs of producing and distributing reliable, clean electricity. Avoiding such costs in the short run only increases them at a compound rate in the long run. When you pay later, you pay more not only to reflect the cost of money but also to compensate for the increased risk of default. It is no accident that now unregulated developers of both conventional and alternative sources of electric energy require long term power sales agreements before the first spade of dirt is turned.

Against that backdrop it is understandable that potential investors in regulated sources of electric energy might be cautious and require some level of certainty before committing billions of dollars to refurbish existing plants or build new ones. The length of the capital recovery cycle for new coal and uranium generating facilities could be 50 years or more. In the new era, it will be the responsibility of management and regulators to work together to create a reliable energy policy environment so that such long term capital needs can be satisfied on reasonable terms.

In the new era, energy policy makers must focus not on the lowest possible prices in the short run (treating electricity like a mere commodity) but on the lowest possible prices consistent with sustained high quality, reliable service in the long run. Prices must be high enough to allow investment in the maintenance, renovation, and new construction necessary to serve growing demand for electricity, satisfy increasingly higher service quality standards, and comply with more rigorous regulations necessary to assure a cleaner environment. The goal of policy makers should be to set prices at levels that permit companies to build and sustain the financial strength necessary to access capital on favorable terms for the long term. In the new era, the ability to plan ahead and raise the necessary capital for long lead time generation projects will require robust financial health. The payoff for customers will be great and the near term cost will be insignificant compared with the long term benefits.

Back to the Future

Reliable electric service is not established in a day, a week, a month, or even a year. Once achieved it must be maintained because it cannot be readily recreated at the dire moment of need. To borrow from a popular movie of the former era, it's time to go *Back to the Future.* It's time to learn from past mistakes and go back to a management and regulatory model that was never broken but can be made better.

Finally, as electric service reliability becomes more dependent upon power plant availability, integrated companies like Westar with strong ties to the communities in which they do business are more likely to remain loyal to the letter and spirit of their public service obligation than unregulated generating companies without any wires business. *The former provides a service, the latter merely trades in a commodity.*

FINANCIAL MEASURES 2004

	2004	2003
FINANCIAL DATA *(Dollars in Millions)*		
INCOME HIGHLIGHTS		
Sales	**$1,464**	$1,461
Income from continuing operations	**100**	163
Results of discontinued operations, net of tax	**79**	(78)
Earnings available for common stock	**178**	84
BALANCE SHEET HIGHLIGHTS		
Total assets	**5,086**	5,743
Common stock equity	**1,388**	1,015
Capital Structure:		
Common equity	**45%**	31%
Preferred stock	**1%**	1%
Debt	**54%**	68%
OPERATING DATA		
Sales (Thousands of MWh)		
Retail	**18,364**	18,384
Wholesale	**8,688**	8,666
Customers	**653,000**	644,000
COMMON STOCK DATA		
PER SHARE HIGHLIGHTS		
Earnings per share:		
Basic earnings from continuing operations	**$1.19**	$2.24
Discontinued operations, net of tax	**$0.95**	$(1.08)
Basic earnings available	**$2.14**	$1.16
Dividends declared per common share	**$0.80**	$0.76
Book value per share	**$16.13**	$13.98
STOCK PRICE PERFORMANCE		
Common stock price range:		
High	**$22.92**	$20.49
Low	**$18.06**	$9.76
Stock price at year end	**$22.87**	$20.25
Stock price appreciation	**12.94%**	104.55%
Total return (assumes reinvested dividends)	**17.37%**	114.47%
Average equivalent common shares outstanding	**82,941,374**	72,428,728
Dividend yield (based on year end annualized dividend)	**4.0%**	3.8%

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, 2004

OR

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

For the transition period from __________ to __________

Commission File Number 1-3523

WESTAR ENERGY, INC.

(Exact name of registrant as specified in its charter)

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

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

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

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

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

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

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

(Title of Class)

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

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

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

The aggregate market value of the voting common equity held by non-affiliates of the registrant was approximately $1,706,425,434 at June 30, 2004.

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

Common Stock, par value $5.00 per share	**86,400,384 shares**
(Class)	(Outstanding at March 1, 2005)

DOCUMENTS INCORPORATED BY REFERENCE:

Description of the document	Part of the Form 10-K
Portions of the Westar Energy, Inc. definitive proxy statement to be used in connection with the registrant's 2005 Annual Meeting of Shareholders	Part III (Item 10 through Item 14) (Portions of Item 10 are not incorporated by reference and are provided herein)

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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 and dividends; environmental matters; nuclear operations; and the overall economy of our service area.

What happens in each case could vary materially from what we expect because of such things as: electric utility deregulation or re-regulation; regulated and competitive markets; ongoing municipal, state and federal activities; economic and capital market conditions; changes in accounting requirements and other accounting matters; changing weather; rates, cost recoveries and other regulatory matters; the impact of changes and downturns in the energy industry and the market for trading wholesale electricity; the outcome of the notice of violation received on January 22, 2004 from the Environmental Protection Agency and other environmental matters; political, legislative, judicial and regulatory developments; the impact of the purported shareholder and employee class action lawsuits filed against us; the impact of our potential liability to David C. Wittig and Douglas T. Lake for unpaid compensation and benefits and the impact of claims they have made against us related to the termination of their employment and the publication of the report of the special committee of the board of directors; the impact of changes in interest rates; changes in, and the discount rate assumptions used for, pension and other post-retirement and post-employment benefit liability calculations, as well as actual and assumed investment returns on pension plan assets; the impact of changing interest rates and other assumptions on our nuclear decommissioning liability for Wolf Creek Generating Station; Kansas Corporation Commission and the North American Electric Reliability Council's utility service reliability standards; homeland security considerations; coal, natural gas, oil and wholesale electricity prices; availability and timely provision of rail transportation for 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.

PART I

ITEM 1. BUSINESS

GENERAL

We are the largest electric utility in Kansas. Unless the context otherwise indicates, all references in this Annual Report on Form 10-K to "the company," "we," "us," "our" and similar words are to Westar Energy, Inc. and its consolidated subsidiaries. The term "Westar Energy" refers to Westar Energy, Inc., a Kansas corporation incorporated in 1924, alone and not together with its consolidated subsidiaries.

We provide electric generation, transmission and distribution services to approximately 653,000 customers in Kansas. Westar Energy provides these services in central and northeastern Kansas, including the cities of Topeka, Lawrence, Manhattan, Salina and Hutchinson. Kansas Gas and Electric Company (KGE), Westar Energy's wholly owned subsidiary, provides these services in south-central and southeastern Kansas, including the city of Wichita, Kansas. Both Westar Energy and KGE conduct business using the name Westar Energy. Our corporate headquarters is located at 818 South Kansas Avenue, Topeka, Kansas 66612.

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

SIGNIFICANT BUSINESS DEVELOPMENTS DURING 2004

Common Stock Issuance

Westar Energy sold approximately 12.5 million shares of its common stock in 2004 for net proceeds of $245.1 million.

Reduction of Debt

During 2004, we reduced our total debt balance by $533.4 million, from $2.2 billion at December 31, 2003 to $1.7 billion at December 31, 2004.

Discontinued Operations — Sale of Protection One

On February 17, 2004, we closed the sale of our interest in Protection One, Inc. (Protection One) to subsidiaries of Quadrangle Capital Partners LP and Quadrangle Master Funding Ltd. (together, Quadrangle). On November 12, 2004, we settled issues remaining after the sale by entering into a settlement agreement with Protection One and Quadrangle that, among other things, terminated a tax sharing agreement, settled Protection One's claims with us related to the tax sharing agreement and settled claims between Quadrangle and us related to the sale transaction. Our net cash payment under the settlement agreement was $13.4 million. We recorded after tax income from discontinued operations of $78.8 million in 2004 and after tax loss from discontinued operations of $77.9 million in 2003.

OPERATIONS

General

Westar Energy supplies electric energy at retail to approximately 352,000 customers in central and northeast Kansas and KGE supplies electric energy at retail to approximately 301,000 customers in south-central and southeastern Kansas. We also supply electric energy at wholesale to the electric distribution systems of 54 cities in Kansas and four electric cooperatives that serve rural areas of Kansas. We have contracts for the sale, purchase or exchange of wholesale electricity with other utilities. In addition, we engage in energy marketing and purchase and sell wholesale electricity in areas outside our historical retail service territory.

Generation Capacity

We have 5,844 megawatts (MW) of generating capacity, of which 2,587 MW is owned or leased by KGE. See "Item 2. Properties" for additional information on our generating units. The capacity by fuel type is summarized below.

Fuel Type	Capacity (MW)	Percent of Total Capacity
Coal	3,292.0	56.3
Nuclear	548.0	9.4
Natural gas or oil	1,920.0	32.9
Diesel fuel	83.0	1.4
Wind	1.2	—
Total	5,844.2	100.0

Our aggregate 2004 peak system net load of 4,455 MW occurred on August 3, 2004. Our net generating capacity combined with firm capacity purchases and sales provided a capacity margin of approximately 20% above system peak responsibility at the time of our 2004 peak system net load.

We have agreed to provide generating capacity to other utilities as set forth below.

Utility	Capacity (MW)	Period Ending
Midwest Energy, Inc.	20	May 2005
Midwest Energy, Inc.	130	May 2008
Midwest Energy, Inc.	125	May 2010
Empire District Electric Company	162	May 2010
Oklahoma Municipal Power Authority	60	December 2013
McPherson Board of Public Utilities (McPherson)	(a)	May 2027

(a) *We provide base load capacity to McPherson. McPherson provides peaking capacity to us. During 2004, we provided approximately 77 MW to, and received approximately 178 MW from, McPherson. The amount of base load capacity provided to McPherson is based on a fixed percentage of McPherson's annual peak system load.*

Fossil Fuel Generation

Fuel Mix

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

Based on MMBtus, our 2004 actual fuel mix was 79% coal, 16% nuclear and 5% natural gas, oil or diesel fuel. We expect in 2005 to use a higher percentage of coal and a lower percentage of uranium because in 2005 we will refuel Wolf Creek. Our fuel mix fluctuates with the operation of Wolf Creek, as discussed below under "— Nuclear Generation," fluctuations in fuel costs, plant availability, customer demand and the cost and availability of wholesale market power.

Coal

Jeffrey Energy Center: The three coal-fired units at Jeffrey Energy Center have an aggregate capacity of 2,213 MW, of which we own an 84% share, or 1,859 MW. We have a long-term coal supply contract with Foundation Coal West to supply coal to Jeffrey Energy Center from 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 indexed 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.

The coal supplied to Jeffrey Energy Center during 2004 was surface mined and had an average Btu content of approximately 8,449 Btu per pound and an average sulfur content of 0.47 lbs/MMBtu (see "— Environmental Matters" for a discussion of sulfur content). The average delivered cost of coal burned at Jeffrey Energy Center during 2004 was approximately $1.24 per MMBtu, or $20.93 per ton.

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 anticipate that the cost of transporting coal may increase due to higher prices for the items subject to contractual escalation.

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

The PRB coal supplied to LaCygne 1 and LaCygne 2 during 2004 had an average Btu content of approximately 8,630 Btu per pound and an average sulfur content of 0.32 lbs/MMBtu. During 2004, the average delivered cost of all coal burned at LaCygne 1 was approximately $0.89 per MMBtu, or $15.51 per ton. The average delivered cost of coal burned at LaCygne 2 was approximately $0.81 per MMBtu, or $13.74 per ton.

Lawrence and Tecumseh Energy Centers: The coal-fired units located at the Lawrence and Tecumseh Energy Centers have an aggregate generating capacity of 752 MW. During 2004, we purchased coal under a contract with Kennecott Coal Sales Company that expired in December 2004. During the first quarter of 2004, we entered into an agreement with Arch Coal, Inc. for coal to be supplied to these energy centers beginning in 2005 and extending through 2009. This contract is expected to provide 100% of the coal requirement for these energy centers through 2007 and 70% of the coal requirements during 2008 and 2009. Approximately 30% of the coal to be delivered under this contract is priced within a specified range of spot market prices for 2005 through 2007 and approximately 43% of the coal to be delivered under this contract is priced within a specified range of spot market prices in 2008 and 2009.

In 2004, the coal supplied to Lawrence and Tecumseh Energy Centers had an average Btu content of approximately 8,905 Btu per pound and an average sulfur content of 0.36 lbs/MMBtu. During 2004, the average delivered cost of all coal burned in the Lawrence units was approximately $1.05 per MMBtu, or $18.58 per ton. The average delivered cost of all coal burned in the Tecumseh units was approximately $1.05 per MMBtu, or $18.65 per ton.

We transport coal from Wyoming using the BNSF railroad under a contract ending in December 2006. We anticipate entering into a similar contract when the current contract expires. We anticipate that the cost of transporting coal may increase due to higher prices for the items subject to contractual escalation.

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

We have entered into all of our coal transportation contracts in the ordinary course of business. Although several rail carriers are capable of serving the coal mines from where our coal originates, several of our generating stations can be served by only one rail carrier. In the event the rail carrier to one of our generating stations fails to provide reliable service, we could experience a disruption of our business that could have a material adverse impact on our business, consolidated financial condition and results of operations.

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, Neosho, Abilene and Hutchinson Energy Centers, in the gas turbine units at our Tecumseh generating station and in the combined cycle units at the State Line facility. We also use natural gas as a supplemental fuel in the coal-fired units at the Lawrence and Tecumseh generating stations. We purchase natural gas in the spot market, which supplies our facilities with a flexible natural gas supply as necessary to meet operational needs. During 2004, we purchased 4.2 million MMBtu of natural gas on the spot market for a total cost of $28.1 million. Natural gas accounted for approximately 1% of our total fuel burned during 2004.

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

We maintain natural gas transportation arrangements for the Abilene and Hutchinson Energy Centers with Kansas Gas Service, a division of ONEOK, Inc. (ONEOK). This contract expires April 30, 2006. We expect to renew or renegotiate a new contract to provide this natural gas transportation prior to the current contract expiration. We meet a portion of our natural gas transportation requirements for the Gordon Evans, Murray Gill, Neosho, Lawrence and Tecumseh Energy Centers through firm natural gas transportation capacity agreements with Southern Star Central Pipeline. We meet all of the natural gas transportation requirements for the State Line facility through a firm natural gas transportation agreement with Southern Star Central Pipeline. The firm transportation agreements that serve the Gordon Evans, Murray Gill, Lawrence and Tecumseh Energy Centers extend through April 1, 2010. The agreement for the Neosho and State Line facilities extends through June 1, 2016.

Oil

Once started with natural gas, most of the steam units at our Gordon Evans, Murray Gill, Neosho and Hutchinson 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 2004 oil was more economical than natural gas, therefore, we used oil as the primary fuel in these generating facilities for most of 2004. During 2004, we burned 10.3 million MMBtu of oil at a total cost of $38.9 million. Oil accounted for approximately 4% of our total MMBtu of fuel burned during 2004. Because oil does not burn as cleanly as natural gas, our ability to use as much oil in the future could be constrained by new environmental rules or future settlements regarding environmental matters.

Oil is also used as a start-up fuel at some of our generating stations, as a primary fuel in the Hutchinson No. 4 combustion turbine and in our diesel generators. We purchase oil in the spot market and under longer-term contracts. 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 or when the primary fuel becomes uneconomical to burn.

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

Other Fuel Matters

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

	2004	2003	2002
Per Million Btu:			
Nuclear	$ 0.39	$ 0.39	$ 0.40
Coal	1.11	1.07	1.05
Natural gas	6.62	4.83	3.62
Oil	3.77	3.24	2.58
Per MWh Generation	$12.64	$12.08	$11.80

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, growth, 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. Constraints in the transmission system 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, 2004 comprised approximately 6% of our total operating expenses.

Energy Marketing Activities

We engage in both financial and physical trading to manage our energy price risks. 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 daily. We also use economic hedging techniques to manage fuel expenditures.

Nuclear Generation

General

Wolf Creek is a 1,166 MW nuclear power plant located near Burlington, Kansas. Wolf Creek began operation in 1985. KGE owns a 47% interest in Wolf Creek, or 548 MW, which represents approximately 9% 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. Wolf Creek is operated by WCNOC, a corporation owned by the co-owners of Wolf Creek. The co-owners pay the operating costs of WCNOC equal to their percentage ownership in Wolf Creek. WCNOC has approximately 1,000 employees.

Fuel Supply

We have 100% of the uranium and conversion services needed to operate Wolf Creek under contract through September 2009. We also have 100% of the enrichment services required to operate Wolf Creek under contract through approximately March 2008. Fabrication requirements are under contract through 2024. We will be exposed to the price risk associated with any components not currently under contract if a counterparty were to fail its contractual obligations.

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 WCNOC believes 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 WCNOC's ability to replace, if necessary, some of these contracts in the event of a protracted supply disruption. WCNOC believes this potential problem is common in the nuclear industry. Accordingly, in the event the affected contracts were required to be replaced, WCNOC believes that the industry and government would arrive at a solution to minimize disruption of the nuclear industry's operations.

Nuclear fuel is amortized to fuel and purchased power based on the quantity of heat produced for the generation of electricity.

Radioactive Waste Disposal

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

A permanent disposal site will not be available for the nuclear industry until 2012 or later. Under current DOE policy, once a permanent site is available, the DOE will accept spent nuclear fuel on a priority basis. The owners of the oldest spent fuel will be given the highest priority. As a result, disposal services for Wolf Creek will not be available prior to 2018. Wolf Creek has on-site temporary storage for spent nuclear fuel. In early 2000, Wolf Creek completed replacement of spent fuel storage racks to increase its on-site storage capacity for all spent fuel expected to be generated by Wolf Creek through the end of its licensed life in 2025.

In 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. The DOE expects that this facility will open in 2012. However, 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 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. WCNOC believes 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 (Compact), and the Compact Commission, which is responsible for causing a new disposal facility to be developed within one of the member states. The Compact Commission selected Nebraska as the host state for the disposal facility. WCNOC and the owners of the other five nuclear units in the Compact provided most of the pre-construction financing for this project. Our net investment in the Compact is approximately $7.4 million.

In December 1998, the Nebraska agencies responsible for considering the developer's license application denied the application. Most of the utilities that had provided the project's pre-construction financing, including WCNOC as well as the Compact Commission itself, 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 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 Compact Commission settled the case. The settlement requires Nebraska to pay the Compact Commission a one-time amount of $140.5 million or, alternatively, four annual installments of $38.5 million beginning in August 2005. The parties agreed to dismiss all pending litigation and appeals relating to this matter. Once Nebraska makes its final payment, it will be relieved of its responsibility to host a disposal facility. Meanwhile, the Compact Commission is pursuing other strategies for providing disposal capability for waste generators in the Compact region.

Outages

Wolf Creek operates on an 18-month refueling and maintenance outage schedule that permits operations during every third calendar year without a refueling outage. Wolf Creek was shut down for 45 days in 2003 for its thirteenth scheduled refueling and maintenance outage, which began on October 18, 2003 and ended on December 2, 2003. 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. We do not defer and amortize the incremental fuel or purchased power costs incurred as a result of a refueling outage. Wolf Creek is scheduled to be taken off-line in the spring of 2005 for its fourteenth refueling and maintenance outage.

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

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. However, because of Wolf Creek's recent experience with unscheduled outages, one additional unscheduled outage before September 30, 2005 may result in the NRC lowering the Wolf Creek rating for one performance indicator. This might require additional NRC inspections to evaluate possible corrective actions that if required might result in additional expense or disruption in Wolf Creek's operation.

Nuclear Decommissioning

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

We expense nuclear decommissioning costs over the expected life of Wolf Creek. The amount we expense is based on an estimate of nuclear decommissioning costs that we will incur upon retirement of the plant. Nuclear decommissioning costs that are recovered in rates are deposited in an external trust fund. In 2004, we expensed approximately $3.9 million for nuclear decommissioning. We record our investment in the nuclear decommissioning fund at fair value. Fair value approximated $91.1 million at December 31, 2004 and $80.1 million at December 31, 2003.

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 for its pro rata share of the plant.

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

The KCC issued an order on April 16, 2003 approving the August 2002 nuclear decommissioning study for Wolf Creek. On June 2, 2003, we filed a funding schedule with the KCC to reflect the KCC's April 16, 2003 order. On October 10, 2003, the KCC approved the funding schedule as filed without any change to our funding obligation. We expect to file an updated decommissioning cost study with the KCC by September 1, 2005.

We charge nuclear decommissioning costs to operating expense in accordance with the July 25, 2001 KCC rate order as modified by the KCC's approval of the funding schedule in the KCC's October 13, 2003 order. Electric rates charged to customers provide for recovery of these nuclear decommissioning costs over the life of Wolf Creek, 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.

Competition and Deregulation

Electric utilities have historically operated in a rate-regulated environment. The Federal Energy Regulatory Commission (FERC), the federal regulatory agency having jurisdiction over our wholesale rates and transmission services, and other utilities have initiated steps 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 (RTOs). RTOs are designed to control the wholesale transmission services of the utilities in their regions, thereby facilitating open and more competitive markets in bulk power.

Regional Transmission Organization

We are a member of the Southwest Power Pool (SPP). On October 1, 2004, FERC granted RTO status to the SPP. As a result, if approved by the KCC, we expect to turn operational control of our transmission system over to the SPP RTO under its membership agreement and applicable tariff. The SPP RTO will operate our transmission system as part of 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.

Regulation and Rates

As a Kansas electric utility, we are subject to the jurisdiction of the KCC, which has general regulatory authority over our rates, extensions and abandonments of service and facilities, valuation of property, the classification of accounts, the issuance of some securities and various other matters. We are also subject to the jurisdiction of 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.

As a result of an earlier KCC order, we will file a request for a rate review with the KCC by May 2, 2005, based on a test year consisting of the 12 months ended December 31, 2004.

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

On January 16, 2004, the KCC issued an order regarding electric service reliability for retail customers. The order was intended to help the KCC assess the reliability of retail electric service. Specifically, the KCC wanted to establish uniform definitions and requirements regarding service obligations, record keeping, customer notification and methods of reporting results to the KCC. On February 10, 2004, the North American Electric Reliability Council (NERC) issued reliability improvement initiatives stemming from the investigation of the August 14, 2003 blackout in portions of the northeastern United States. These initiatives will impact our operations in a number of ways, including system relay protection, vegetation management and operator training. The NERC and the ten operating regions in the United States, including the SPP, are working together to determine what operating policies and planning standards changes are necessary to achieve the NERC's goals. We are unable to estimate potential compliance costs at this time; however, it is likely that our annual capital and maintenance expenditure requirements will increase in the future.

Public Utility Holding Company Act of 1935

Westar Energy is a holding company under the Public Utility Holding Company Act of 1935 (1935 Act) as a result of Westar Energy's ownership of KGE and Westar Generating, Inc., each a wholly-owned subsidiary. Currently, Westar Energy claims an exemption from registration under the 1935 Act based on its operations being conducted "predominantly" within Kansas. Following a recent decision by the Securities and Exchange Commission (SEC) with respect to its interpretation of the criteria that must be satisfied to claim a "predominantly" intrastate exemption and as a result of the amount of sales of wholesale electricity outside of Kansas by Westar Energy's energy marketing operations, it is possible that the SEC could question Westar Energy's eligibility for an exemption from registration under the 1935 Act. In that event, we would evaluate our options, including filing an application for exemption and asking the SEC to formally consider that request, becoming a registered holding company, restructuring our operations in a manner that would allow us to maintain eligibility to claim an exemption or restructuring our organizational structure to consolidate all utility operations into one entity so that Westar Energy is no longer a utility holding company.

In the event we elect to register Westar Energy as a holding company, the 1935 Act and related regulations issued by the SEC would govern its activities and the activities of its subsidiaries with respect to the acquisition, issuance and sale of securities, acquisition and sale of utility assets, certain transactions among affiliates, engaging in business activities not directly related to the utility or energy business and other matters. We are unable to predict whether Westar Energy will continue to be eligible for an exemption for registration under the 1935 Act, however, we believe that Westar Energy becoming a registered holding company under the 1935 Act or taking steps to reorganize our corporate structure to avoid registration would not have a material impact on our consolidated financial position, results of operations or cash flows.

Environmental Matters

General

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

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

Air Emissions

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

Certain Kansas Department of Health and Environment (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. Because of strong demand for generation during 2002 and 2003, we consumed more SO2 allowances than were allocated to us by the EPA. We made up the shortfall by buying allowances. In 2004, we had enough emissions allowances to meet planned generation and we expect to have enough in 2005. 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 January 30, 2004, the EPA published two proposed air quality rules referred to as the "Interstate Air Quality Rule" and the "Utility Mercury Reduction Rule" that, if adopted, would impact our operations. In an attempt to address the impact of interstate transport of air pollutants on downwind states, the proposed Clean Air Interstate Rule would require reductions of SO2 and NOx in certain states, including Kansas, in two separate phases. The first reductions would be required in 2010 and the second in 2015.

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

We may be required to further reduce emissions of SO2, NOx, particulate matter, mercury and carbon dioxide (CO2) as a result of various other current or pending laws, including, in particular:

- the EPA's national ambient air quality standards for particulate matter and ozone,
- the EPA's regional haze rules, designed to reduce SO2, NOx and particulate matter emissions, and
- additional legislation introduced in the past few years in Congress, such as the various "multi-pollutant" bills sponsored by members of Congress requiring reductions of CO2, NOx, SO2 and mercury, and the "Clear Skies" legislation proposed by the President, which would cap emissions of NOx, SO2 and mercury.

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

EPA New Source Review

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

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

We are in discussions with the EPA concerning this matter in an attempt to reach a settlement. We expect that any settlement with the EPA could require us to update or install emissions controls at Jeffrey Energy Center over an agreed upon number of years. Additionally, we might be required to update or install emissions controls at our other coal-fired plants, pay fines or penalties, or take other remedial action. Together, these costs could be material. The EPA has informed us 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 rates. If we were to reach a settlement with the EPA, we may be assessed a penalty. The penalty could be material and may not be recovered in rates.

Manufactured Gas Sites

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

We and the KDHE entered into a consent agreement in 1994 governing all future work at the Kansas sites. Under the terms of the consent agreement, we agreed to investigate and, if necessary, remediate these sites. Through December 31, 2004, the costs incurred for preliminary site investigation and risk assessment have been minimal. Pursuant to an environmental indemnity agreement with ONEOK, the current owner of some of the Kansas sites, our liability for twelve of the Kansas sites is limited. Of those twelve sites, ONEOK assumed total liability for remediation of seven sites and we share liability for remediation with ONEOK for five sites. Our total liability for the five shared sites is capped at $3.8 million and terminates in 2012. We have sole responsibility for remediation with respect to three Kansas sites. With respect to two of those sites, we are currently either conducting or completing remediation activities and, with respect to the third site, we will begin investigation activities in the near future.

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

Solid Waste Landfills

We operate solid waste landfills at Jeffrey, Lawrence and Tecumseh Energy Centers for the single purpose of disposing of coal combustion waste material. Additionally, there is one retired landfill at each of the Lawrence and Neosho Energy Centers. All landfills are permitted by the KDHE. The operating landfill at Lawrence Energy Center is projected to be full by late 2007 or early 2008 requiring us to permit and construct a new landfill at this site. We began the process of obtaining this permit in late 2003. We will continue to work with the appropriate regulatory agencies to ensure that the new landfill and expansion of the existing landfill will meet the operating requirements of the Lawrence Energy Center.

EMPLOYEES

As of February 28, 2005, we employed approximately 2,100 people. Our current contract with Local 304 and Local 1523 of the International Brotherhood of Electrical Workers extends through June 30, 2005. The contract is currently under negotiation. The contract covered approximately 1,200 employees as of February 28, 2005.

ACCESS TO COMPANY INFORMATION

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

RISK FACTORS

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

Our Revenues Depend Upon Rates Determined by the KCC

The KCC regulates many aspects of our business and operations, including the retail rates that we may charge customers for electric service. 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, including potentially stranded obligations. Using this approach, the KCC sets rates at a level calculated to recover such costs, adjusted to reflect known and measurable changes, and a permitted return on investment. Other parties to a rate review or the KCC staff may contend that our current or proposed rates are excessive. In July 2003, the KCC approved a stipulation and agreement that requires us to file for a rate review, which may or may not include a request for a change in rates, by May 2, 2005, and to pay customer rebates of $10.5 million on May 1, 2005 and $10.0 million on January 1, 2006. The rates permitted by the KCC in the rate review will determine our revenues for the succeeding periods and may have a material impact on our consolidated earnings, cash flows and financial position, as well as our ability to maintain our common stock dividend at current levels or to increase our dividend in the future. We are unable to predict the outcome of the rate review.

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

Once established by the KCC, our rates remain fixed until changed in a subsequent rate review. We may at any time 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. Earnings could be reduced to the extent that increases in our operating costs increase more than our revenues during the period between rate reviews, which may occur because of maintenance and repair of plants, fuel and purchased power expenses, employee or labor costs, inflation or other factors.

Equipment Failures and Other External Factors Can Adversely Affect Our Results

The generation and transmission of electricity requires the use of expensive and complicated equipment. While we have a maintenance program in place, generating plants are subject to unplanned outages because of equipment failure. In these events, we must either produce replacement power from our less efficient units or purchase power from others at unpredictable cost in order to supply our customers and perform our contractual agreements. This can increase our costs materially and prevent or limit us from selling power at wholesale, thus reducing our profits. In addition, decisions or mistakes by other utilities may adversely affect our ability to use transmission lines to deliver or import power, thus subjecting us to unexpected expenses or to the cost and uncertainty of public policy initiatives. These factors, as well as weather, interest rates, economic conditions, fuel availability and prices, price volatility of fuel and other commodities and transportation availability and costs are largely beyond our control, but may 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 us that certain projects completed at Jeffrey Energy Center violated pre-construction permitting requirements under the Clean Air Act. This notification was delivered as part of an investigation by the EPA regarding maintenance activities that have been conducted since 1980 at Jeffrey Energy Center. The EPA has informed us 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, the cost of which could be material.

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

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

We currently apply the accounting principles of Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation," to our regulated business and at December 31, 2004 had recorded $413.7 million of regulatory assets, net of regulatory liabilities. In the event that we determined that we could no longer apply the principles of SFAS No. 71, either as a result of the establishment of retail competition in Kansas or an expectation that permitted rates would not allow us to recover these costs, we would be required to record a charge against income in the amount of the remaining unamortized net regulatory assets. Neither the Kansas Legislature nor the KCC has taken action in the recent past to establish retail competition in our service territory.

We Face Financial Risks From Our Ownership Interest in the Wolf Creek 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 and uncertainties with respect to the technological aspects of nuclear decommissioning at the end of their useful lives and anticipated increases in the cost of nuclear decommissioning and costs or measures associated with public safety. In the event of an extended or unscheduled outage at Wolf Creek, we would be required to 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. Such purchases would subject us to the risk of increased energy prices and, depending on the length of the outage and the level of market prices, could adversely affect our cash flow. If we were not permitted by the KCC to recover these costs, such events could have an adverse impact on our consolidated financial condition.

We May Face Liability In Ongoing Lawsuits and Investigations

We and certain of our former and present directors and officers are defendants in civil litigation alleging violations of the securities laws. In addition, we continue to cooperate in investigations by a federal grand jury, the SEC and the DOJ into events that occurred at our company during the years prior to 2003. Our former president, chief executive officer and chairman and our former executive vice president and chief strategic officer have asserted significant claims against us in connection with the termination of their employment and the publication of the report of the special committee of our board of directors. An adverse result in any of these matters could result in damages, fines or penalties in amounts that could be material and adversely affect our consolidated results and financial condition. Management believes that it is not currently possible to estimate the potential impact of the ultimate resolution of these matters.

EXECUTIVE OFFICERS OF THE COMPANY

Name	Age	Present Office	Other Offices or Positions Held During the Past Five Years
James S. Haines, Jr.	58	Director, Chief Executive Officer and President (since December 2002)	**The University of Texas at El Paso** Adjunct Professor and Skov Professor of Business Ethics (January 2002 to Present) **El Paso Electric Company** Director, President and Chief Executive Officer (May 1996 to November 2001)
William B. Moore	52	Executive Vice President and Chief Operating Officer (since December 2002)	**Saber Partners, LLC** Senior Managing Director and Senior Advisor (October 2000 to December 2002) **Westar Energy, Inc.** Executive Vice President, Chief Financial Officer and Treasurer (May 1999 to August 2000)
Mark A. Ruelle	43	Executive Vice President and Chief Financial Officer (since January 2003)	**Sierra Pacific Resources, Inc.** President, Nevada Power Company (June 2001 to May 2002) Senior Vice President, Chief Financial Officer (March 1997 to May 2001)
Douglas R. Sterbenz	41	Senior Vice President, Generation and Marketing (since October 2001)	**Westar Energy, Inc.** Senior Director, Bulk Power Marketing (January 1999 to October 2001)
Bruce A. Akin	40	Vice President, Administrative Services (since December 2001)	**Westar Energy, Inc.** Executive Director, Business Services (October 2001 to December 2001) Executive Director, Human Resources (July 1999 to October 2001)
Kelly B. Harrison	46	Vice President, Regulatory (since December 2001)	**Westar Energy, Inc.** Executive Director, Regulatory (October 2001 to December 2001) Senior Director, Restructuring and Rates (October 1999 to October 2001)
Larry D. Irick	48	Vice President, General Counsel and Corporate Secretary (since February 2003)	**Westar Energy, Inc.** Vice President and Corporate Secretary (December 2001 to February 2003) Corporate Secretary (May 2000 to December 2001) Executive Director, Law (May 1999 to May 2000)
Peggy S. Loyd	47	Vice President, Corporate Compliance and Internal Audit (since March 2003)	**Westar Energy, Inc.** Vice President, Financial Services (May 2000 to March 2003) Executive Director, Financial Services (January 1999 to May 2000)
James J. Ludwig	46	Vice President, Public Affairs (since January 2003)	**Westar Energy, Inc.** Senior Director, Regulatory Affairs (July 1995 to October 2001)
Lee Wages	56	Vice President, Controller (since December 2001)	**Westar Energy, Inc.** Controller (July 1999 to December 2001)

ITEM 2. PROPERTIES

Name/Location	Unit No.	Year Installed	Principal Fuel	Unit Capacity (MW) By Owner Westar Energy	KGE	Total Company
Abilene Energy Center:						
Abilene, Kansas						
Combustion Turbine	1	1973	Gas	72.0	—	72.0
Gordon Evans Energy Center:						
Colwich, Kansas						
Steam Turbines	1	1961	Gas – Oil	—	149.0	149.0
	2	1967	Gas – Oil	—	383.0	383.0
Combustion Turbines	1	2000	Gas	74.0	—	74.0
	2	2000	Gas	74.0	—	74.0
	3	2001	Gas	151.0	—	151.0
Diesel Generator	1	1969	Diesel	—	3.0	3.0
Hutchinson Energy Center:						
Hutchinson, Kansas						
Steam Turbines	1	1950	Gas – Oil	17.0	—	17.0
	2	1950	Gas – Oil	16.0	—	16.0
	3	1951	Gas – Oil	28.0	—	28.0
	4	1965	Gas – Oil	173.0	—	173.0
Combustion Turbines	1	1974	Gas	54.0	—	54.0
	2	1974	Gas	55.0	—	55.0
	3	1974	Gas	56.0	—	56.0
	4	1975	Diesel	77.0	—	77.0
Diesel Generator	1	1983	Diesel	3.0	—	3.0
Jeffrey Energy Center (84%):						
St. Marys, Kansas						
Steam Turbines	1 [a]	1978	Coal	471.0	147.0	618.0
	2 [a]	1980	Coal	470.0	147.0	617.0
	3 [a]	1983	Coal	475.0	149.0	624.0
Wind Turbines	1 [a]	1999	—	0.5	0.1	0.6
	2 [a]	1999	—	0.5	0.1	0.6
LaCygne Station (50%):						
LaCygne, Kansas						
Steam Turbines	1 [a]	1973	Coal	—	344.0	344.0
	2 [b]	1977	Coal	—	337.0	337.0
Lawrence Energy Center:						
Lawrence, Kansas						
Steam Turbines	3	1954	Coal	54.0	—	54.0
	4	1960	Coal	122.0	—	122.0
	5	1971	Coal	372.0	—	372.0
Murray Gill Energy Center:						
Wichita, Kansas						
Steam Turbines	1	1952	Gas	—	40.0	40.0
	2	1954	Gas – Oil	—	71.0	71.0
	3	1956	Gas – Oil	—	104.0	104.0
	4	1959	Gas – Oil	—	102.0	102.0
Neosho Energy Center:						
Parsons, Kansas						
Steam Turbine	3	1954	Gas – Oil	—	63.0	63.0
State Line (40%):						
Joplin, Missouri						
Combined Cycle	2-1 [a]	2001	Gas	65.0	—	65.0
	2-2 [a]	2001	Gas	64.0	—	64.0
	2-3 [a]	2001	Gas	71.0	—	71.0
Tecumseh Energy Center:						
Tecumseh, Kansas						
Steam Turbines	7	1957	Coal	75.0	—	75.0
	8	1962	Coal	129.0	—	129.0
Combustion Turbines	1	1972	Gas	18.0	—	18.0
	2	1972	Gas	20.0	—	20.0
Wolf Creek Generating Station (47%):						
Burlington, Kansas						
Nuclear	1 [a]	1985	Uranium	—	548.0	548.0
Total				3,257.0	2,587.2	5,844.2

[a] *We jointly own Jeffrey Energy Center (84%), LaCygne 1 generating unit (50%), Wolf Creek Generating Station (47%) and State Line (40%). Unit capacity amounts reflect our ownership only.*

[b] *In 1987, KGE entered into a sale-leaseback transaction involving its 50% interest in the LaCygne 2 generating unit.*

We own approximately 6,100 miles of transmission lines, approximately 23,600 miles of overhead distribution lines and approximately 3,300 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

On September 21, 2004, a grand jury in Travis County, Texas, indicted us on charges that a $25,000 contribution by us in May 2002 to a Texas political action committee violated Texas election laws. We believe the indictment is without merit and we intend to vigorously defend against the charges. If convicted, the court could impose a fine of up to $20,000 or, in certain circumstances, in an amount not to exceed twice the amount caused to be lost by the commission of the felony. As a result of the indictment, the federal government could suspend our status as a government contractor. Upon a conviction, the federal government could bar us from acting as a government contractor. We are taking action to ensure that neither of these events occur, but we do not know whether we will be successful. We are unable to predict the ultimate impact either suspension or loss of our status as a government contractor would have on our consolidated financial position, results of operations and cash flows.

Information on other legal proceedings is set forth in Notes 3, 15, 17, 18 and 20 of the Notes to Consolidated Financial Statements, "Rate Matters and Regulation," "Commitments and Contingencies — EPA New Source Review," "Legal Proceedings," "Ongoing Investigations" and "Potential Liabilities to David C. Wittig and Douglas T. Lake," respectively, which are incorporated herein by reference.

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

No matter was submitted to a vote of our security holders through the solicitation of proxies or otherwise during the fourth quarter of 2004.

PART II

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

STOCK TRADING

Our common stock is listed on the New York Stock Exchange and traded under the ticker symbol WR. As of March 1, 2005, there were 29,503 common shareholders of record. For information regarding quarterly common stock price ranges for 2004 and 2003, see Note 26 of the Notes to Consolidated Financial Statements, "Quarterly Results (Unaudited)."

DIVIDENDS

Holders of our common stock are entitled to dividends when and as declared by our board of directors. However, prior to the payment of common dividends, we must first pay dividends to the holders of preferred stock based on the fixed dividend rate for each series.

Quarterly dividends on common stock and preferred stock have historically been paid on or about the first business day of January, April, July and October to shareholders of record as of or about the ninth day of the preceding month. Our board of directors reviews our common stock dividend policy from time to time. Among the factors the board of directors considers in determining our dividend policy are earnings, cash flows, capitalization ratios, regulation, competition and financial loan covenants. On November 23, 2004, our board of directors declared a quarterly dividend of $0.23 per share, payable January 3, 2005.

Our articles of incorporation restrict the payment of dividends or the making of other distributions on our common stock while any preferred shares remain outstanding unless we meet certain capitalization ratios and other conditions. We provide further information on these restrictions in Note 19 of the Notes to Consolidated Financial Statements, "Common and Preferred Stock." We do not expect these restrictions to have an impact on our ability to pay dividends on our common stock.

For additional information on dividends, see Note 19 of the Notes to Consolidated Financial Statements, "Common and Preferred Stock," included herein.

ITEM 6. SELECTED FINANCIAL DATA

For the Year Ended December 31,	2004	2003	2002[(a)]	2001	2000
			(In Thousands)		
Income Statement Data:					
Sales	$1,464,489	$1,461,143	$1,423,151	$1,308,536	$1,361,006
Income from continuing operations before accounting change	100,080	162,915	88,816	59,333	192,696
Earnings (loss) available for common stock	177,900	84,042	(793,400)	(21,771)	135,352

As of December 31,	2004	2003	2002	2001	2000
			(In Thousands)		
Balance Sheet Data:					
Total assets	$5,085,711	$5,742,975	$6,756,666	$7,718,764	$7,887,746
Long-term obligations and mandatorily redeemable preferred stock[(b)]	1,724,967	2,259,880	3,225,556	2,915,153	2,938,832

For the Year Ended December 31,	2004	2003	2002[(a)]	2001	2000
Common Stock Data:					
Basic earnings per share available for common stock from continuing operations before accounting change	$ 1.19	$ 2.24	$ 1.23	$ 0.83	$ 2.78
Basic earnings (loss) per share available for common stock	$ 2.14	$ 1.16	$ (11.06)	$ (0.31)	$ 1.96
Dividends declared per share	$ 0.80	$ 0.76	$ 1.20	$ 1.20	$ 1.44
Book value per share	$ 16.13	$ 13.98	$ 13.41	$ 25.64	$ 27.28
Average equivalent common shares outstanding (in thousands)	82,941	72,429	71,732	70,650	68,962

[(a)] *See Note 4 of the Notes to Consolidated Financial Statements, "Discontinued Operations — Sale of Protection One and Protection One Europe" for discussion of impairment charges that are the primary cause of our losses.*

[(b)] *Includes long-term debt, capital leases, affiliate long-term debt and shares subject to mandatory redemption.*

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

INTRODUCTION

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

Our focus during 2004 was the continued reduction of our debt and interest expense, primarily through issuing stock, the sale of our interest in Protection One and by refinancing some of our debt at lower interest rates. In 2004, we reduced our debt by $533.4 million.

Our goals for 2005 are to improve our core utility business by improving our credit quality, establishing a successful clean air plan, completing a successful rate review, improving our service quality, making our operations more efficient and continuing our involvement in community affairs.

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

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

CRITICAL ACCOUNTING ESTIMATES

We base our discussion and analysis of financial condition and results of operations 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.

Pension Benefit Plans

We calculate our pension benefit and post-retirement medical benefit obligations and related costs 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," respectively.

In accounting for our retirement plans and other post-retirement benefits, we make assumptions regarding the valuation of benefit obligations and the performance of plan assets. The reported costs of our pension benefit plans, which include our portion of WCNOC's costs, are impacted by estimates regarding earnings on plan assets, contributions to the plan, discount rates used to determine our projected benefit obligation and pension costs and employee demographics including age, compensation levels and employment periods. A change in any of these assumptions could have a significant impact on future costs, which may be reflected as an increase or decrease in net income in the 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% decrease in our pension plan discount rate and rate of return on plan assets. If the discount rate increased by 0.5%, the impact would be a similar amount in the opposite direction.

	Change in Assumption	Annual Increase in Projected Benefit Obligation	Annual Increase in Pension Liability	Annual Increase in Projected Pension Expense
			(In Thousands)	
Discount rate	0.5% decrease	$35,227	$32,134	$2,850
Rate of return on plan assets	0.5% decrease	—	—	2,299

The following table shows the annual impact of a 0.5% decrease in our post-retirement plan discount rate and rate of return on plan assets. If the discount rate increased by 0.5%, the impact would be a similar amount in the opposite direction.

	Change in Assumption	Annual Increase in Projected Benefit Obligation	Annual Increase in Post-retirement Liability	Annual Increase in Projected Post-retirement Expense
			(In Thousands)	
Discount rate	0.5% decrease	$6,243	$—	$333
Rate of return on plan assets	0.5% decrease	—	—	120

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, 2004, we had estimated unbilled revenue of $47.6 million.

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. Unless related to fuel, we include the net mark-to-market change in sales on our consolidated statements of income (loss). 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, 2004, their sources and maturity periods.

	Fair Value of Contracts
	(In Thousands)
Net fair value of contracts outstanding at the beginning of the period	$10,464
Contracts outstanding at the beginning of the period that were realized or otherwise settled during the period	(7,293)
Changes in fair value of contracts outstanding at the beginning and end of the period	(2,590)
Fair value of new contracts entered into during the period	5,500
Fair value of contracts outstanding at the end of the period	$ 6,081

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

	Fair Value of Contracts at End of Period			
Sources of Fair Value	Total Fair Value	Maturity Less Than 1 Year	Maturity 1-3 Years	Maturity 4-5 Years
Prices provided by other external sources (swaps and forwards)	$2,255	$1,396	$(377)	$1,236
Prices based on the Black Option Pricing model (options and other)[a]	3,826	1,328	500	1,998
Total fair value of contracts outstanding	$6,081	$2,724	$ 123	$3,234

[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.

We record deferred tax assets for capital loss, operating loss and tax credit carryforwards. However, when there are not sufficient sources of future capital gain income or taxable income to realize the benefit of the capital loss, operating loss or tax credit carryforwards, we reduce the deferred tax assets by a valuation allowance. We recognize a valuation allowance if, based on the weight of available evidence, it is considered more likely than not that some portion or all of the deferred tax asset will not be realized. We report the effect of a change in the valuation allowance in the current period tax expense.

OPERATING RESULTS

We evaluate operating results based on basic earnings (loss) per share. 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: Includes the sales of electricity to electric cooperatives, municipalities and other electric utilities, the rate for which is generally based on cost as prescribed by FERC tariffs, and changes in valuations of contracts that have yet to settle.

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

Energy marketing: Includes: (1) market-based energy transactions unrelated to our generation or the needs of our regulated customers; (2) financially settled products and physical transactions sourced outside our control area; and (3) changes in valuations for contracts that have yet to settle that may not be recorded either in cost of fuel or 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 and available generation capacity.

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.

Year Ended December 31,	2004	2003	Change	% Change
	(In Thousands, Except Per Share Amounts)			
SALES:				
Residential	$ 425,150	$ 432,955	$ (7,805)	(1.8)
Commercial	386,991	382,585	4,406	1.2
Industrial	239,518	240,538	(1,020)	(0.4)
Other retail	(46)	5,363	(5,409)	(100.9)
Total Retail Sales	1,051,613	1,061,441	(9,828)	(0.9)
Tariff-based wholesale	143,868	140,687	3,181	2.3
Market-based wholesale	140,465	125,995	14,470	11.5
Energy marketing	26,321	31,881	(5,560)	(17.4)
Transmission[(a)]	77,540	76,379	1,161	1.5
Other	24,682	24,760	(78)	(0.3)
Total Sales	1,464,489	1,461,143	3,346	0.2
OPERATING EXPENSES:				
Fuel used for generation	353,617	342,522	11,095	3.2
Purchased power	66,171	47,790	18,381	38.5
Operating and maintenance	412,002	371,372	40,630	10.9
Depreciation and amortization	169,310	167,236	2,074	1.2
Selling, general and administrative	173,498	160,825	12,673	7.9
Total Operating Expenses	1,174,598	1,089,745	84,853	7.8
INCOME FROM OPERATIONS	289,891	371,398	(81,507)	(21.9)
OTHER INCOME (EXPENSE):				
Investment earnings	16,746	21,189	(4,443)	(21.0)
ONEOK dividends	—	17,316	(17,316)	(100.0)
Gain on sale of ONEOK stock	—	99,327	(99,327)	(100.0)
Loss on extinguishment of debt and settlement of putable/callable notes	(18,840)	(26,455)	7,615	28.8
Other income	2,756	2,854	(98)	(3.4)
Other expense	(14,879)	(16,590)	1,711	10.3
Total Other Income (Expense)	(14,217)	97,641	(111,858)	(114.6)
Interest expense	142,151	224,356	(82,205)	(36.6)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	133,523	244,683	(111,160)	(45.4)
Income tax expense	33,443	81,768	(48,325)	(59.1)
INCOME FROM CONTINUING OPERATIONS	100,080	162,915	(62,835)	(38.6)
Results of discontinued operations, net of tax	78,790	(77,905)	156,695	201.1
NET INCOME	178,870	85,010	93,860	110.4
Preferred dividends	970	968	2	0.2
EARNINGS AVAILABLE FOR COMMON STOCK	$ 177,900	$ 84,042	$ 93,858	111.7
BASIC EARNINGS PER SHARE	$ 2.14	$ 1.16	$ 0.98	84.5

[(a)]***Transmission:*** *Includes an SPP network transmission tariff. In 2004, our transmission costs were approximately $66.6 million. This amount, less $4.3 million that was retained by the SPP as administration cost, was returned to us as revenues. In 2003, our transmission costs were approximately $65.3 million with an administration cost of $5.7 million retained by the SPP.*

The following table reflects changes in electric sales volumes, as measured by thousands of megawatt hours (MWh) of electricity, for the two 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	5,925	6,031	(106)	(1.8)
Commercial	6,867	6,801	66	1.0
Industrial	5,470	5,448	22	0.4
Other retail	102	104	(2)	(1.9)
Total Retail	18,364	18,384	(20)	(0.1)
Tariff-based wholesale	4,573	4,747	(174)	(3.7)
Market-based wholesale	4,115	3,919	196	5.0
Total	27,052	27,050	2	—

Our retail customers used less energy and our sales decreased because of cooler weather during the summer. When measured by cooling degree days, the weather during 2004 was 12% cooler than during 2003 and 16% below the 20-year average. We measure cooling degree days at weather stations we believe to be generally reflective of conditions in our service territory. 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 $8.5 million as compared to $3.5 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 the 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 $6.7 million of the increased market-based wholesale sales and higher average market prices accounted for approximately $7.8 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 expense increased due primarily to increases in the cost of fossil fuels, although we used approximately 2% less fuel for generation due to the lower demand caused by the cooler weather and due to unplanned outages or reduced operating capability experienced at some of our generating units at various times throughout 2004. The average equivalent availability factor for our system was 87% during 2004 compared to 90% in the prior year, due largely to the unavailability of some of our coal-fired generating units. As a result of the cooler weather and the reduced availability of our coal-fired generating units, we decreased the amount of coal burned, and consequently reduced our total expense for coal. However, the cost of natural gas and oil that we used at other generating facilities to compensate for the unplanned outages or reduced operating capability, increased our total fuel expense.

Purchased power expense increased due primarily to a 34% increase in volumes purchased during 2004 as compared to 2003. At times, it was more economical to purchase power than to operate our available generating units. This was due to unplanned outages or reduced operating capability of our coal-fired generating units at certain times, and the availability of economically priced power due to cooler weather in our region.

During 2003, we recorded as an offset to operating and maintenance expense a gain of $11.9 million on the sale of utility assets. The absence of a similar offset in 2004 accounted for 29% of the increase in operating and maintenance expense in 2004. The remainder of the increase was caused primarily by 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, an increase in taxes other than income tax and an increase in the transmission costs. During 2004, increased maintenance of our generating units accounted for 23% of the increase in operating and maintenance expenses. The increase in distribution expenses accounted for 17% 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 shared services agreement as discussed in Note 24 of the Notes to Consolidated Financial Statements, "Related Party Transactions — ONEOK Shared Services Agreement." The change in taxes other than income tax accounted for 22% of the increase in operating and maintenance expenses. An increase in transportation costs accounted for 3% of the increase in operating and maintenance expenses.

Selling, general and administrative expenses increased due primarily to an increase in legal fees, including amounts we were required to advance for fees incurred by David C. Wittig, our former president, chief executive officer and chairman, and Douglas T. Lake, our former executive vice president, chief strategic officer and member of the board, related to the defense of criminal charges against them, and fees associated with the pending shareholder class action and derivative lawsuits.

The total other expense during 2004 was due primarily to the loss incurred on the extinguishment of debt. The total other income during 2003 was due primarily to the gain on the sale of our ONEOK stock and dividends received from ONEOK in 2003. This gain was partially offset by the loss recorded on the extinguishment of debt and the settlement of notes during 2003.

Interest expense decreased in 2004 due to lower debt balances and lower interest rates due to refinancing activities as discussed below in "Liquidity and Capital Resources."

Income from discontinued operations was $78.8 million in 2004. The results recorded for 2004 include the settlement of previously pending issues as discussed in Note 4 of the Notes to Consolidated Financial Statements, "Discontinued Operations — Sale of Protection One and Protection One Europe." This compares to a loss from discontinued operations of $77.9 million in 2003.

2003 compared to 2002: Below we discuss our operating results for the year ended December 31, 2003 as compared to the results for the year ended December 31, 2002.

Year Ended December 31,	2003	2002	Change	% Change
	(In Thousands, Except Per Share Amounts)			
SALES:				
Residential	$ 432,955	$ 442,106	$ (9,151)	(2.1)
Commercial	382,585	385,375	(2,790)	(0.7)
Industrial	240,538	242,847	(2,309)	(1.0)
Other retail	5,363	8,071	(2,708)	(33.6)
Total Retail Sales	1,061,441	1,078,399	(16,958)	(1.6)
Tariff-based wholesale	140,687	138,111	2,576	1.9
Market-based wholesale	125,995	100,586	25,409	25.3
Energy marketing	31,881	7,049	24,832	352.3
Transmission[a]	76,379	76,199	180	0.2
Other	24,760	22,807	1,953	8.6
Total Sales	1,461,143	1,423,151	37,992	2.7
OPERATING EXPENSES:				
Fuel used for generation	342,522	347,377	(4,855)	(1.4)
Purchased power	47,790	32,123	15,667	48.8
Operating and maintenance	371,372	379,220	(7,848)	(2.1)
Depreciation and amortization	167,236	171,807	(4,571)	(2.7)
Selling, general and administrative	160,825	218,345	(57,520)	(26.3)
Total Operating Expenses	1,089,745	1,148,872	(59,127)	(5.1)
INCOME FROM OPERATIONS	371,398	274,279	97,119	35.4
OTHER INCOME (EXPENSE):				
Investment earnings	21,189	30,024	(8,835)	(29.4)
ONEOK dividends	17,316	46,771	(29,455)	(63.0)
Gain on sale of ONEOK stock	99,327	—	99,327	—
Loss on extinguishment of debt and settlement of putable/callable notes	(26,455)	(1,541)	(24,914)	(1,616.7)
Other income	2,854	1,316	1,538	116.9
Other expense	(16,590)	(38,380)	21,790	56.8
Total Other Income	97,641	38,190	59,451	155.7
Interest expense	224,356	235,172	(10,816)	(4.6)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	244,683	77,297	167,386	216.5
Income tax expense (benefit)	81,768	(11,519)	93,287	809.9
INCOME FROM CONTINUING OPERATIONS	162,915	88,816	74,099	83.4
Results of discontinued operations, net of tax	(77,905)	(881,817)	803,912	91.2
NET INCOME	85,010	(793,001)	878,011	110.7
Preferred dividends, net of gain on reacquired preferred stock	968	399	569	142.6
EARNINGS AVAILABLE FOR COMMON STOCK	$ 84,042	$ (793,400)	$877,442	110.6
EARNINGS PER SHARE	$ 1.16	$ (11.06)	$ 12.22	110.5

[a] ***Transmission:*** *Includes an SPP network transmission tariff. In 2003, our transmission costs were approximately $65.3 million. This amount, less $5.7 million that was retained by the SPP as administration cost, was returned to us as revenues. In 2002, our transmission costs were approximately $65.9 million with an administration cost of $5.7 million retained by the SPP.*

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

	2003	2002	Change	% Change
	(Thousands of MWh)			
Residential	6,031	6,170	(139)	(2.3)
Commercial	6,801	6,817	(16)	(0.2)
Industrial	5,448	5,451	(3)	(0.1)
Other retail	104	106	(2)	(1.9)
Total retail	18,384	18,544	(160)	(0.9)
Tariff-based wholesale	4,747	4,905	(158)	(3.2)
Market-based wholesale	3,919	4,210	(291)	(6.9)
Total	27,050	27,659	(609)	(2.2)

Our retail customers used less energy and our sales declined because of cooler weather as well as the sale of a small portion of our rural distribution territory. Commercial and industrial sales revenues showed slight decreases while sales volumes remained relatively flat compared to 2002. The decline in retail sales volumes accounted for approximately $10.2 million of the decline in retail sales revenues. The accrual of approximately $3.5 million to be refunded to customers in 2005 and 2006 pursuant to a KCC order also contributed to the decline in retail sales revenues.

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

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

Operating and maintenance expense declined due primarily to the $11.9 million gain recorded in 2003 on the sale of utility assets, which was recorded as an offset to operating expenses. General maintenance expenses at our generating facilities increased by $8.5 million, partially offsetting the decline in operating expenses.

Depreciation and amortization expense decreased due to the adoption of new depreciation rates on April 1, 2002.

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

Other income improved significantly in 2003 primarily because the mark to market charge to record the fair value of the call option associated with the 6.25% senior unsecured notes that were putable and callable on August 15, 2003 (the putable/callable notes) was $2.2 million for 2003 compared to a charge of $22.6 million for 2002. The smaller mark to market charge in 2003 was the result of the settlement of the call options related to the putable/callable notes in August 2003.

LIQUIDITY AND CAPITAL RESOURCES

Overview

We believe we will have sufficient cash to fund future operations, debt maturities, the rebates to customers we are required to make in 2005 and 2006, and the payment of dividends from a combination of cash on hand, cash flows from operations and available borrowing capacity. Our available sources of funds include cash, Westar Energy's revolving credit facility, our accounts receivable conduit facility and access to capital markets. At December 31, 2004, we had cash and cash equivalents of $24.6 million, $284.7 million available under the revolving credit facility and $45.0 million available under the accounts receivable conduit facility. Uncertainties affecting our ability to meet these requirements include, among others, factors affecting sales described in "Operating Results" above, economic conditions, regulatory actions, conditions in the capital markets and compliance with environmental regulations.

At December 31, 2004, our total outstanding long-term debt, net of current maturities, was approximately $1.6 billion compared to a balance of approximately $2.1 billion at December 31, 2003. At December 31, 2004, our current maturities of long-term debt were $65.0 million compared to $185.9 million at December 31, 2003.

Capital Resources

We had $24.6 million in unrestricted cash and cash equivalents at December 31, 2004. We consider cash equivalents to be highly liquid investments with maturities of three months or less at the time they are purchased.

At December 31, 2004, we also had $12.3 million of restricted cash classified as a current asset and $27.4 million of restricted cash classified as a long-term asset, primarily to provide credit security for energy marketing transactions. The following table details our restricted cash at December 31, 2004.

	Restricted Cash Current Portion	Restricted Cash Long-term Portion
	(In Thousands)	
Prepaid capacity and transmission agreement	$ 2,256	$25,982
Cash held in escrow as required by certain letters of credit, surety bonds and various other deposits	10,023	1,426
Total	$12,279	$27,408

The Westar Energy mortgage and the KGE mortgage each contain provisions restricting the amount of first mortgage bonds that could be issued by each entity. Additionally, Westar Energy's revolving credit facility prohibits us from increasing the amount of secured indebtedness outstanding as of March 12, 2004 by more than $300.0 million. 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 Westar Energy mortgage prohibits additional first mortgage bonds from being issued, except in connection with certain refundings, unless Westar Energy's unconsolidated net earnings available for interest, depreciation and property retirement (which as defined, does not include earnings or losses attributable to the ownership of securities of subsidiaries), for a period of 12 consecutive months within 15 months preceding the issuance, are not less than the greater of twice the annual interest charges on, and 10% of the principal amount of, all first mortgage bonds outstanding after giving effect to the proposed issuance. In addition, the issuance of bonds is subject to limitations based on the amount of bondable property additions. At December 31, 2004, based on an assumed interest rate of 6%, approximately $210.0 million principal amount of additional first mortgage bonds could be issued under the most restrictive provisions in the mortgage, except in connection with certain refundings.

The KGE mortgage prohibits additional first mortgage bonds from being issued, except in connection with certain refundings, unless KGE's net earnings before income taxes and before provision for retirement and depreciation of property for a period of 12 consecutive months within 15 months preceding the issuance are not less than either two and one-half times the annual interest charges on, or 10% of the principal amount of, all KGE first mortgage bonds outstanding after giving effect to the proposed issuance. In addition, the issuance of bonds is subject to limitations based on the amount of bondable property additions. At December 31, 2004, based on an assumed interest rate of 6%, approximately $874.0 million principal amount of additional KGE first mortgage bonds could be issued under the most restrictive provisions in the mortgage.

Westar Energy's revolving credit facility prohibits us from increasing the amount of secured indebtedness outstanding as of March 12, 2004 by more than $300.0 million. In June 2004, Westar Energy issued $250.0 million of Westar Energy first mortgage bonds and immediately placed the funds in escrow for retirement of $225.0 million of Westar Energy first mortgage bonds, which was completed in July 2004. Therefore, at December 31, 2004, we could incur a maximum of $275.0 million of additional secured debt under this provision in the Westar Energy revolving credit facility. Following Westar Energy's January 18, 2005 issuance of $250.0 million of first mortgage bonds, as discussed in "— Debt Financings," we can incur a maximum of $25.0 million of additional secured debt under this provision in Westar Energy's revolving credit facility.

Westar Energy sold approximately 12.5 million shares of its common stock in 2004 for net proceeds of $245.1 million.

Cash Flows from Operating Activities

Cash flows from operating activities increased $203.6 million to $354.2 million in 2004 from $150.6 million for 2003. This increase was primarily attributable to reduced interest of $80.2 million and reduced tax payments of $52.5 million.

Cash flows from operating activities decreased $127.5 million to $150.6 million in 2003 from $278.1 million in 2002. This decrease was mostly attributable to taxes paid in 2003 of $53.6 million compared to an income tax refund received in 2002 of $54.1 million, an increase in maintenance expenditures at our generating facilities in 2003 as compared to 2002, and increased legal expenditures in 2003 related to investigations and litigation.

Cash Flows (used in) from Investing Activities

In general, cash used for investing purposes relates to the growth and improvement of our electric utility business. The utility business is capital intensive and requires significant investment in plant on an annual basis. We spent $202.9 million in 2004, $163.5 million in 2003, and $140.4 million in 2002 on net additions to utility property, plant and equipment.

In 2004, we received net proceeds of $108.3 million from the sale of Protection One and Protection One bonds. During 2003, we received net proceeds of $801.8 million from the sale of ONEOK stock and net proceeds of $33.3 million from the sale of utility assets. Proceeds from other investments includes ONEOK dividends, proceeds from the sale of investments in affordable housing tax credit limited partnerships and proceeds from the sale of other investments.

Cash Flows (used in) Financing Activities

Financing activities in 2004 used $323.2 million of cash compared to $881.1 million in 2003. In 2004, we received cash from issuances of long-term debt and the issuance of common stock, and cash was used for the retirement of long-term debt and payment of dividends.

We used $881.1 million of cash in 2003 for financing activities compared to $72.4 million in 2002. In 2003, cash was used in financing activities for the retirement of long-term debt and the payment of dividends. In 2003, we reduced our indicated annual dividend from $1.20 per share to $0.76 per share.

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

Future Cash Requirements

Our business requires significant capital investments. Through 2007, we expect we will need cash mostly for utility construction programs designed to improve facilities providing electric service and for future peaking capacity needs. In 2006 we anticipate additional cash expenditures necessary to purchase and build approximately 150 MW of peaking generation capacity that we anticipate will be needed in 2008. We expect to meet these cash needs with internally generated cash flow and borrowing under Westar Energy's revolving credit facility.

We are required to pay rebates to retail customers of $10.5 million on May 1, 2005 and $10.0 million on January 1, 2006. We believe we can fund these rebates with internally generated cash flow and available borrowing capacity under Westar Energy's revolving credit facility.

If we are required to update emissions controls or take other remedial action as a result of the EPA's investigation, the costs could be material. We may also have to pay fines or penalties or make significant capital or operational expenditures related to the notice of violation we received from the EPA in connection with certain projects completed at 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. The following table does not include any amounts related to these possible expenditures. In addition, KCPL, the operator of our jointly owned LaCygne Generating Station, has informed us that it is considering updating or installing additional equipment related to emissions controls at the LaCygne Generating Station. If KCPL decides to complete this work, we will incur costs beginning in 2005 and continuing through the completion of installation in 2007. We expect that costs related to updating or installing emissions controls will be material. These costs are not included in the following table. We believe that these costs would qualify for recovery through rates.

Capital expenditures for 2004 and anticipated capital expenditures for 2005 through 2007, including costs of removal, are shown in the following table.

	Actual 2004	2005	2006	2007
	(In Thousands)			
Replacements and other	$ 138,376	$ 151,600	$ 152,600	$ 168,200
Additional capacity	5,513	7,700	17,300	42,100
New customer construction	38,038	45,700	64,300	49,500
Nuclear fuel	20,965	4,900	19,300	24,000
Total capital expenditures	$ 202,892	$ 209,900	$ 253,500	$ 283,800

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 or other enacted or proposed environmental regulations. Environmental expenditures could be material.

Maturities of long-term debt at December 31, 2004 are as follows.

Year	Principal Amount
	(In Thousands)
2005	$ 65,000
2006	100,000
2007	625,000
2008	—
2009	145,078
Thereafter	769,823
	$1,704,901

Debt Financings

During 2004, we made changes in our long-term debt as shown in the table below.

	Balance as of December 31, 2003	Securities Redeemed	Securities Issued	Balance as of December 31, 2004
	(In Thousands)			
Long-term Debt Redemptions and Issuances:				
Westar Energy				
First mortgage bond series:				
6.00% due 2014	$ —	$ —	$ 250,000	$ 250,000
8.5% due 2022	125,000	(125,000)	—	—
7.65% due 2023	100,000	(100,000)	—	—
Pollution control bond series:				
6.00% due 2033	58,340	(58,340)	—	—
5.00% due 2033	—	—	58,340	58,340
6-7/8% senior unsecured notes due August 1, 2004	184,456	(184,456)	—	—
9-3/4% senior unsecured notes due 2007	387,000	(127,000)	—	260,000
6.80% senior unsecured notes due 2018	26,993	(26,993)	—	—
Senior secured term loan due 2005	114,143	(114,143)	—	—
	$995,932	$(735,932)	$ 308,340	$ 568,340
KGE				
Pollution control bond series:				
7.00% due 2031	$327,500	$(327,500)	$ —	$ —
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 rate due 2031	—	—	100,000	100,000
	$327,500	$(327,500)	$ 327,500	$ 327,500
Long-term debt affiliate	$103,093	$(103,093)	$ —	$ —

On March 12, 2004, Westar Energy entered into a revolving credit facility. The credit facility matures on March 12, 2007. It is used as a source of short-term liquidity. It allows us borrowings up to an aggregate limit of $300.0 million, including letters of credit up to a maximum aggregate amount of $50.0 million. At December 31, 2004, we had no outstanding borrowings and $15.3 million of letters of credit outstanding under the revolving credit facility. All borrowings under the revolving credit facility are secured by KGE first mortgage bonds.

On January 18, 2005, Westar Energy sold $250.0 million aggregate principal amount of Westar Energy first mortgage bonds, consisting of $125.0 million 5.15% bonds maturing in 2017 and $125.0 million 5.95% bonds maturing in 2035. On February 17, 2005, we used the net proceeds from the offering, together with cash on hand, additional funds raised through the accounts receivable conduit facility and borrowings under Westar Energy's revolving credit facility, to redeem the remaining $260.0 million aggregate principal amount of Westar Energy 9.75% senior notes due 2007. Together with accrued interest and a premium equal to approximately 12% of the outstanding senior notes, we paid $298.5 million to redeem the Westar Energy 9.75% senior notes due 2007. After this transaction, we had $10.0 million outstanding under the revolving credit facility and $30.0 million available under the accounts receivable conduit facility.

Debt Covenants

Some of our debt instruments contain restrictions that require us to maintain various coverage and leverage ratios as defined in the agreements. We calculate these ratios in accordance with our credit agreements. These ratios are used solely to determine compliance with our various debt covenants. We were in compliance with these covenants at December 31, 2004.

Interest Rate Swap

Effective October 4, 2001, we entered into a $500.0 million interest rate swap agreement with a term of two years. At that time, the effect of the swap agreement was to fix the annual interest rate on a term loan at 6.18%. We settled the swap agreement for a nominal amount on September 29, 2003. For information regarding ongoing interest rates, see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

Credit Ratings

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

On February 23, 2005, Moody's upgraded its ratings for our debt and affirmed the speculative liquidity rating it assigned to us of SGL-2, reflecting its view that we have "good" liquidity. On December 22, 2004, Fitch raised its outlook rating to positive from stable and affirmed its ratings as shown in the table below. On July 22, 2004, S&P improved its ratings on KGE's first mortgage bonds to BBB from BB+.

As of March 1, 2005, 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 KGE have credit rating conditions under our revolving credit agreement and in the agreements governing the sale of our accounts receivable discussed in Note 5 of the Notes to Consolidated Financial Statements, "Accounts Receivable and Variable Interest Entities" 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, 2004 and 2003 was as follows.

	2004	2003
Common equity	45%	31%
Preferred stock	1%	1%
Debt	54%	68%
Total	100%	100%

OFF-BALANCE SHEET ARRANGEMENTS

Accounts Receivable Sales Program

Under a revolving accounts receivable sales program, we currently sell up to $125.0 million of our accounts receivable. For additional detail, see Note 5 of the Notes to Consolidated Financial Statements, "Accounts Receivable and Variable Interest Entities."

LaCygne 2 Sale/Leaseback Agreement

In 1987, KGE sold and leased back its 50% undivided interest in the LaCygne 2 generating unit. The LaCygne 2 lease has an initial term of 29 years, with various options to renew the lease or repurchase the 50% undivided interest. KGE remains responsible for its share of operating and maintenance costs and other related operating costs of LaCygne 2. The lease is an operating lease for financial reporting purposes. We recognized a gain on the sale, which was deferred and is being amortized over the lease term. See Note 23 of the Notes to Consolidated Financial Statements, "Leases," for additional information.

CONTRACTUAL OBLIGATIONS AND COMMERCIAL COMMITMENTS

In the course of our business activities, we enter into a variety of contractual obligations and commercial commitments. Some of these result in direct obligations reflected on our consolidated balance sheets while others are commitments, some firm and some based on uncertainties, not reflected in our underlying consolidated financial statements. The obligations listed below do not include amounts for on-going needs for which no contractual obligations existed at December 31, 2004, and represent only those amounts that we were contractually obligated to meet at December 31, 2004. We may from time to time enter into new contracts to replace contracts that expire.

Contractual Cash Obligations

The following table summarizes the projected future cash payments for our contractual obligations existing at December 31, 2004.

Contractual Obligations	Total	2005[c]	2006[c]-2007	2008-2009	Thereafter
			(In Thousands)		
Long-term debt[a] ...	$1,704,901	$ 65,000	$ 725,000	$145,078	$ 769,823
Interest payments on long-term debt[b] ..	846,537	107,087	199,523	85,136	454,791
Adjusted long-term debt	2,551,438	172,087	924,523	230,214	1,224,614
Capital leases[d]	24,201	5,267	8,569	5,903	4,462
Operating leases[e] ..	613,898	49,422	140,041	69,145	355,290
Fossil fuel[f]	1,569,155	188,304	339,237	295,529	746,085
Nuclear fuel[g]	162,691	4,404	39,898	12,649	105,740
Unconditional purchase obligations	34,612	28,601	6,011	—	—
Miscellaneous obligations	2,032	816	1,216	—	—
Total contractual obligations, including adjusted long-term debt	$4,958,027	$448,901	$1,459,495	$613,440	$2,436,191

[a] *See Note 11 of the Notes to Consolidated Financial Statements, "Long-term Debt," for individual long-term debt maturities.*

[b] *We calculate interest payments on our variable rate debt based on the effective interest rate at December 31, 2004.*

[c] *We have an obligation to pay rebates to customers in 2005 and 2006.*

[d] *Includes principal and interest on capital leases.*

[e] *Includes the LaCygne 2 lease, office space, operating facilities, office equipment, operating equipment and other miscellaneous commitments.*

[f] *Coal and natural gas commodity and transportation contracts.*

[g] *Uranium concentrates, conversion, enrichment, fabrication and spent fuel disposal.*

Commercial Commitments

Our commercial commitments existing at December 31, 2004 are outstanding letters of credit that expire in 2005. The letters of credit are comprised of $6.6 million related to our energy marketing and trading activities, $5.2 million related to worker's compensation and $4.5 million related to other operating activities for a total outstanding balance of $16.3 million.

OTHER INFORMATION

Ice Storm

On January 4 and 5, 2005, substantially all of our service territory experienced a severe ice storm. The storm interrupted electric service in a large portion of our service territory and damaged a significant portion of our electric distribution system. We estimate that we will incur $38.0 million to $42.0 million of system restoration costs. Of this amount, we expect $6.0 million to $8.0 million to be accounted for as capital expenditures and we expect the balance related to maintenance expenditures to be accounted for as a regulatory asset. On February 3, 2005, we filed an application for an accounting authority order with the KCC requesting that we be allowed to accumulate and defer for future recovery maintenance costs related to system restoration. We can provide no assurance that the KCC will approve our application, however, in the past the KCC has approved similar requests.

New Accounting Pronouncements

In December 2004, the Financial Accounting Standards Board (FASB) issued SFAS No. 123R, "Share-Based Payment: An Amendment of FASB Statements No. 123 and 95." SFAS No. 123R requires companies to recognize as compensation expense the grant-date fair value of stock options and other equity-based compensation issued to employees. The provisions of the statement are effective for financial statements issued for periods that begin after June 15, 2005, which will be our third quarter beginning July 1, 2005.

We currently use RSUs for stock-based awards granted to employees. In addition, we have eliminated our employee stock purchase plan and all outstanding options have vested. Given the characteristics of our stock-based compensation program, we do not expect the adoption of SFAS No. 123R to materially impact our results of operations.

Sale of Utility Assets

In August 2003, we sold a portion of our transmission and distribution assets and rights to provide service to approximately 10,000 customers in an area of central Kansas. Total sales proceeds received were $33.3 million and we realized a gain of $11.9 million. We may enter into similar transactions in the future.

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 electric utility operations. If we determine that we no longer meet the criteria of SFAS No. 71, we may have a material non-cash charge to earnings.

At December 31, 2004, we had recorded regulatory assets currently subject to recovery in future rates of approximately $442.9 million. Of this amount, $191.6 million is related to income tax benefits previously passed on to customers. The remainder of the regulatory assets include asset retirement obligations, system restoration, loss on reacquired debt, refinancing costs on the LaCygne 2 lease, deferred employee benefit costs, deferred plant costs and coal contract settlement costs. We periodically review SFAS No. 71 criteria and believe that our net regulatory assets are probable of future recovery.

Asset Retirement Obligations

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

Legal Liability — Wolf Creek

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

Non-legal Liability — Cost of Removal

We have recovered amounts in rates to provide for recovery of the probable costs of removing utility plant assets, but which do not represent legal retirement obligations. At December 31, 2004, Westar Energy had $1.3 million in removal costs classified as a regulatory asset and KGE had $2.6 million in removal costs classified as a regulatory liability. At December 31, 2003, we had $6.6 million in removal costs classified as a regulatory asset. The net amount related to non-legal retirement costs can fluctuate based on amounts related to removal costs recovered compared to removal costs incurred.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Hedging Activity

We use 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 increases. 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 6 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 and an interest rate swap we 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. This volatility may increase or decrease future earnings.

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

Credit risk represents the risk of loss resulting from non-performance by a counterparty of its contractual obligations. We have exposure to credit risk and counterparty default 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 engage in both financial and physical trading to manage our commodity price risk. We trade electricity, coal, natural gas and oil. We use financial instruments, including forward contracts, options and swaps and we trade energy commodity contracts daily. We may also use economic hedging techniques to manage overall fuel expenditures. We procure physical product under forward agreements and spot market transactions.

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 manage and measure the market price risk exposure of our trading portfolio using a variance/covariance value-at-risk (VaR) model. The VaR model is designed to measure the predicted maximum one-day loss at a 95% confidence level. In addition to VaR, we employ additional risk control processes such as stress testing, daily loss limits, credit limits and position limits. We expect to use similar control processes in 2005.

The use of the VaR method requires assumptions, including the selection of a confidence level for potential losses and the estimated holding period. This means that we are also exposed to the risk that we value and mark illiquid prices incorrectly. We express VaR as a potential dollar loss based on a 95% confidence level using a one-day holding period. The calculation includes derivative commodity instruments used for both trading and risk management purposes. The VaR amounts for 2004 and 2003 were as follows.

	2004	2003
	(In Thousands)	
High	$2,891	$1,393
Low	713	144
Average	1,321	722

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 we believe are effective in managing overall credit risk. There can be no assurance that the employment of VaR, or other risk management tools we employ, will eliminate the risk of loss.

We are also exposed to commodity price changes outside of trading activities. We use derivative contracts for non-trading purposes and a mix of various fuel types primarily to reduce exposure relative to the volatility of market and commodity prices. The wholesale power market is extremely volatile in price and supply. This volatility impacts our costs of power purchased and our participation in energy trades. If we were unable to generate an adequate supply of electricity for our 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 increased expenses or loss of revenues associated with this could be material and adverse to our consolidated results of operations and financial condition.

From 2003 to 2004, we experienced an approximate 6% increase in the average price per MWh of electricity purchased for utility operations. Volatility in the prices for power we purchase could be greater than the average price increase indicates. Additionally, short-term, but extreme price volatility could potentially be of greater significance than the change in the average price would indicate, especially during adverse weather or market conditions. If we were to have a 10% increase in our purchased power price from 2004 to 2005, given the amount of power purchased for utility operations during 2004, we would have exposure of approximately $4.7 million of operating income. Due to the volatility of the power market, we believe past prices are not a good predictor of future prices.

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. During 2004, we experienced an approximate 37% increase, or $1.79 per MMBtu, in our average cost for natural gas purchased for utility operations. 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. The average cost for oil purchased for utility operations increased $0.53 per MMBtu, or approximately 16%, compared to the average cost in 2003. The average cost of oil burned was $2.85 per MMBtu less than the average cost of the natural gas we burned. If we were to have a 10% increase in our price for natural gas and oil burned from 2004 to 2005, based on MMBtus of natural gas and oil burned during 2004, we would have exposure of approximately $6.7 million of operating income. Due to the volatility of natural gas prices, past prices cannot be used to predict future prices.

We have 100% of the uranium and conversion services required to operate Wolf Creek under contract through September 2009. We also have 100% of the enrichment services required to operate Wolf Creek under contract through March 2008. We will be exposed to the price risk associated with any components not currently under contract if a counterparty were to fail its contractual obligations.

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

Interest Rate Exposure

We had approximately $286.9 million of variable rate debt and current maturities of fixed rate debt at December 31, 2004. A 100 basis point change in interest rates applicable to this debt would impact operating income on an annualized basis by approximately $2.8 million.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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SCHEDULES OMITTED

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

I, III, IV, and V.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

We are responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is defined in Rules 13a-15(f) promulgated under the Securities Exchange Act of 1934 as a process designed by, or under the supervision of, the company's principal executive and principal financial officers and effected by the company's board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles and includes those policies and procedures that:

- Pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the company;
- Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and
- Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

We assessed the effectiveness of our internal control over financial reporting at December 31, 2004. In making this assessment, we used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control — Integrated Framework. Based on the assessment, we believe that, at December 31, 2004, our internal control over financial reporting is effective based on those criteria. Our independent registered public accounting firm has issued an audit report on our assessment of our internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited management's assessment, included in the accompanying Management's Report on Internal Controls over Financial Reporting, that Westar Energy, Inc. and subsidiaries (the "Company") maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2004 of the Company and our report dated March 11, 2005 expressed an unqualified opinion on those financial statements and financial statement schedule.

DELOITTE & TOUCHE LLP

Kansas City, Missouri
March 11, 2005

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Westar Energy, Inc. and subsidiaries (the "Company") as of December 31, 2004 and 2003, and the related consolidated statements of income (loss), comprehensive income (loss), shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2004. 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. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company and subsidiaries as of December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004, 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 16 to the consolidated financial statements, effective January 1, 2003, the Company adopted Statement of Financial Accounting Standard No. 143, "Accounting for Asset Retirement Obligations."

As discussed in Note 5 to the consolidated financial statements, effective October 1, 2003, the Company adopted FIN 46R, "Consolidation of Variable Interest Entities."

As discussed in Note 4 to the consolidated financial statements, effective January 1, 2002, the Company adopted Statement of Financial Accounting Standard No. 142, "Goodwill and Other Intangible Assets," and Statement of Financial Accounting Standard No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets."

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of December 31, 2004, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 11, 2005 expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

DELOITTE & TOUCHE LLP

Kansas City, Missouri
March 11, 2005

WESTAR ENERGY, INC. CONSOLIDATED BALANCE SHEETS

As of December 31,	2004	2003
	(Dollars in Thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 24,611	$ 79,559
Restricted cash	12,279	17,925
Accounts receivable, net	92,532	80,971
Inventories and supplies	124,563	134,931
Energy marketing contracts	23,155	35,385
Tax receivable	90,845	5,961
Deferred tax assets	7,218	123,256
Prepaid expenses	29,179	32,430
Other	11,558	10,747
Assets of discontinued operations	—	570,541
Total Current Assets	415,940	1,091,706
PROPERTY, PLANT AND EQUIPMENT, NET	3,910,987	3,909,500
OTHER ASSETS:		
Restricted cash	27,408	31,854
Regulatory assets	442,944	411,315
Nuclear decommissioning trust	91,095	80,075
Energy marketing contracts	4,904	4,190
Other	192,433	214,335
Total Other Assets	758,784	741,769
TOTAL ASSETS	$ 5,085,711	$ 5,742,975
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Current maturities of long-term debt	$ 65,000	$ 185,941
Short-term debt	—	1,000
Accounts payable	105,593	92,994
Accrued taxes	97,874	108,249
Energy marketing contracts	20,431	28,000
Accrued interest	30,506	33,651
Other	99,170	85,904
Liabilities of discontinued operations	—	475,597
Total Current Liabilities	418,574	1,011,336
LONG-TERM LIABILITIES:		
Long-term debt, net	1,639,901	1,948,253
Long-term debt, affiliate	—	103,093
Unamortized investment tax credits	68,957	74,291
Deferred income taxes	927,087	969,544
Deferred gain from sale-leaseback	138,981	150,810
Accrued employee benefits	120,152	121,308
Asset retirement obligation	87,118	80,695
Nuclear decommissioning	91,095	80,075
Energy marketing contracts	1,547	1,111
Other	182,977	165,699
Total Long-Term Liabilities	3,257,815	3,694,879
COMMITMENTS AND CONTINGENCIES (see notes 15 and 17)		
SHAREHOLDERS' EQUITY:		
Cumulative preferred stock, par value $100 per share; authorized 600,000 shares; issued and outstanding 214,363 shares	21,436	21,436
Common stock, par value $5 per share; authorized 150,000,000 shares; issued 86,029,721 shares and 72,840,217 shares, respectively	430,149	364,201
Paid-in capital	912,932	776,754
Unearned compensation	(10,361)	(15,879)
Loans to officers	—	(2)
Retained earnings (accumulated deficit)	55,053	(102,782)
Treasury stock, at cost, 0 and 203,575 shares, respectively	—	(2,391)
Accumulated other comprehensive income (loss), net	113	(4,577)
Total Shareholders' Equity	1,409,322	1,036,760
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 5,085,711	$ 5,742,975

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

WESTAR ENERGY, INC. CONSOLIDATED STATEMENTS OF INCOME (LOSS)

Year Ended December 31,	2004	2003	2002
	(Dollars in Thousands, Except Per Share Amounts)		
SALES	$ 1,464,489	$ 1,461,143	$ 1,423,151
OPERATING EXPENSES:			
Fuel and purchased power	419,788	390,312	379,500
Operating and maintenance	412,002	371,372	379,220
Depreciation and amortization	169,310	167,236	171,807
Selling, general and administrative	173,498	160,825	218,345
Total Operating Expenses	1,174,598	1,089,745	1,148,872
INCOME FROM OPERATIONS	289,891	371,398	274,279
OTHER INCOME (EXPENSE):			
Investment earnings	16,746	38,505	76,795
Gain on sale of ONEOK stock	—	99,327	—
Loss on extinguishment of debt and settlement of putable/callable notes	(18,840)	(26,455)	(1,541)
Other income	2,756	2,854	1,316
Other expense	(14,879)	(16,590)	(38,380)
Total Other Income (Expense)	(14,217)	97,641	38,190
Interest expense	142,151	224,356	235,172
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES AND CUMULATIVE EFFECT OF ACCOUNTING CHANGE	133,523	244,683	77,297
Income tax expense (benefit)	33,443	81,768	(11,519)
INCOME FROM CONTINUING OPERATIONS BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	100,080	162,915	88,816
Results of discontinued operations, net of tax			
Discontinued operations, net of tax	78,790	(77,905)	(258,100)
Cumulative effect of accounting change, net of tax	—	—	(623,717)
Results of discontinued operations, net of tax	78,790	(77,905)	(881,817)
NET INCOME (LOSS)	178,870	85,010	(793,001)
Preferred dividends, net of gain on reacquired preferred stock	970	968	399
EARNINGS (LOSS) AVAILABLE FOR COMMON STOCK	$ 177,900	$ 84,042	$ (793,400)
BASIC AND DILUTED EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING (see note 2):			
Basic earnings available from continuing operations before accounting change	$ 1.19	$ 2.24	$ 1.23
Discontinued operations, net of tax	0.95	(1.08)	(3.60)
Accounting change, including discontinued operations, net of tax	—	—	(8.69)
Basic earnings (loss) available	$ 2.14	$ 1.16	$ (11.06)
Diluted earnings available from continuing operations before accounting change	$ 1.19	$ 2.20	$ 1.22
Discontinued operations, net of tax	0.94	(1.06)	(3.57)
Accounting change, including discontinued operations, net of tax	—	—	(8.63)
Diluted earnings (loss) available	$ 2.13	$ 1.14	$ (10.98)
Average equivalent common shares outstanding	82,941,374	72,428,728	71,731,580
DIVIDENDS DECLARED PER COMMON SHARE	$ 0.80	$ 0.76	$ 1.20

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

WESTAR ENERGY, INC. CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

Year Ended December 31,	**2004**		2003		2002	
			(Dollars in Thousands)			
NET INCOME (LOSS)		**$178,870**		$ 85,010		$ (793,001)
OTHER COMPREHENSIVE INCOME:						
Unrealized holding gain on marketable securities arising during the period	**$ 11**		$ 99,412		$ —	
Reclassification adjustment for gain included in net income	**—**	**11**	(99,310)	102	—	—
Unrealized holding gain on cash flow hedges arising during the period	**—**		12,270		19,466	
Reclassification adjustment for (gain) loss included in net income	**—**	**—**	(4,543)	7,727	1,992	21,458
Minimum pension liability adjustment		**7,769**		284		(1,341)
Foreign currency translation adjustment		**—**		—		1,044
Other comprehensive income, before tax		**7,780**		8,113		21,161
Income tax expense related to items of other comprehensive income		**(3,090)**		(3,188)		(8,032)
Other comprehensive gain, net of tax		**4,690**		4,925		13,129
COMPREHENSIVE INCOME (LOSS)		**$183,560**		$ 89,935		$ (779,872)

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

WESTAR ENERGY, INC. CONSOLIDATED STATEMENTS OF CASH FLOWS

Year Ended December 31,	2004	2003	2002
		(Dollars in Thousands)	
CASH FLOWS FROM (USED IN) OPERATING ACTIVITIES:			
Net income (loss)	**$ 178,870**	$ 85,010	$ (793,001)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Discontinued operations, net of tax	**(78,790)**	77,905	881,817
Depreciation and amortization	**169,310**	167,236	171,807
Amortization of nuclear fuel	**14,221**	12,410	13,142
Amortization of deferred gain from sale-leaseback	**(11,828)**	(11,828)	(11,828)
Amortization of prepaid corporate-owned life insurance	**12,622**	14,320	20,321
Non-cash stock compensation	**7,916**	6,885	14,006
Net changes in energy marketing assets and liabilities	**4,383**	(1,855)	20,229
Loss on extinguishment of debt and settlement of putable/callable notes	**18,840**	26,455	1,541
Net changes in fair value of call option	**—**	2,178	22,609
Equity in earnings from investments	**—**	—	(9,670)
Gain on sale of ONEOK stock	**—**	(99,327)	—
Accrued liability to certain former officers	**8,384**	1,205	22,928
(Gain) loss on sale of utility plant and property	**(503)**	(11,912)	1,424
Net deferred income taxes and credits	**(5,215)**	(100,275)	35,111
Changes in working capital items, net of acquisitions and dispositions:			
Restricted cash	**7,825**	(4,794)	(6,596)
Accounts receivable, net	**(11,561)**	(32,031)	(4,534)
Inventories and supplies	**10,368**	8,607	(8,955)
Prepaid expenses and other	**(40,557)**	16,897	(49,079)
Accounts payable	**12,182**	6,231	(21,396)
Accrued taxes	**43,463**	81,135	(7,834)
Other current liabilities	**(5,046)**	(84,021)	(13,339)
Changes in other, assets	**10,566**	2,451	(30,869)
Changes in other, liabilities	**8,738**	(12,245)	30,247
Cash flows from operating activities	**354,188**	150,637	278,081
CASH FLOWS FROM (USED IN) INVESTING ACTIVITIES:			
Additions to property, plant and equipment	**(188,447)**	(150,378)	(126,763)
Removal, dismantlement and salvage of property, plant and equipment	**(14,445)**	(13,094)	(13,621)
Investment in corporate-owned life insurance	**(19,658)**	(19,599)	(19,399)
Proceeds from investment in corporate-owned life insurance	**—**	—	7,859
Proceeds from sale of Protection One	**81,670**	—	—
Proceeds from sale of Protection One bonds	**26,640**	—	—
Proceeds from sale of plant and property	**8,604**	33,303	1,205
Proceeds from sale of international investment	**11,219**	—	—
Proceeds from sale of ONEOK stock	**—**	801,841	—
Issuance of officer loans and interest, net of payments	**2**	438	(308)
Proceeds from other investments	**9,591**	801	18,296
Cash flows (used in) from investing activities	**(84,824)**	653,312	(132,731)
CASH FLOWS FROM (USED IN) FINANCING ACTIVITIES:			
Short-term debt, net	**(1,000)**	—	(221,300)
Proceeds from long-term debt	**623,301**	—	1,350,069
Retirements of long-term debt	**(1,188,081)**	(963,330)	(1,021,993)
Funds in trust for debt repayments	**78**	145,182	(135,000)
Purchase of call option investment	**—**	(65,785)	—
Repayment of capital leases	**(4,977)**	(5,138)	(5,019)
Borrowings against cash surrender value of corporate-owned life insurance	**57,090**	58,818	61,120
Repayment of borrowings against cash surrender value of corporate-owned life insurance	**(444)**	(419)	(8,490)
Issuance of common stock, net	**245,130**	—	2,551
Cash dividends paid	**(56,189)**	(57,726)	(73,535)
Retirement of preferred stock	**—**	—	(1,547)
Acquisition of treasury stock	**—**	—	(19,544)
Reissuance of treasury stock	**1,927**	7,260	255
Cash flows (used in) financing activities	**(323,165)**	(881,138)	(72,433)
Net cash (used in) from discontinued operations	**(1,147)**	43,699	(48,059)
Foreign currency translation	**—**	—	1,044
NET (DECREASE) INCREASE IN CASH AND CASH EQUIVALENTS	**(54,948)**	(33,490)	25,902
CASH AND CASH EQUIVALENTS:			
Beginning of period	**79,559**	113,049	87,147
End of period	**$ 24,611**	$ 79,559	$ 113,049

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

WESTAR ENERGY, INC. CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

	2004		2003		2002	
Year Ended December 31,	**Shares**	**Amount**	Shares	Amount	Shares	Amount
			(Dollars in Thousands)			
Cumulative preferred stock:						
Beginning balance	**214,363**	**$ 21,436**	214,363	$ 21,436	239,364	$ 23,936
Retirement of preferred stock	**—**	**—**	—	—	(25,001)	(2,500)
Ending balance	**214,363**	**21,436**	214,363	21,436	214,363	21,436
Common stock:						
Beginning balance	**72,840,217**	**364,201**	72,840,217	364,201	86,205,417	431,027
Issuance of common stock	**13,189,504**	**65,948**	—	—	6,936,289	34,681
Retirement of common stock	**—**	**—**	—	—	(20,301,489)	(101,507)
Ending balance	**86,029,721**	**430,149**	72,840,217	364,201	72,840,217	364,201
Paid-in capital:						
Beginning balance		**776,754**		825,744		1,196,765
Preferred dividends, net of retirements		**653**		728		(1,035)
Issuance of common stock, net		**192,337**		—		76,586
Dividends on common stock		**(46,473)**		(53,501)		(87,088)
Retirement of common stock		**—**		—		(349,397)
Issuance of treasury stock		**1,230**		671		2
Grant of restricted stock		**1,417**		7,631		7,872
Stock compensation		**(12,986)**		(4,519)		(17,961)
Ending balance		**912,932**		776,754		825,744
Unearned compensation:						
Beginning balance		**(15,879)**		(14,742)		(21,920)
Grant of restricted stock		**(1,417)**		(7,631)		(7,872)
Amortization of restricted stock		**6,838**		6,494		8,647
Forfeited restricted stock		**97**		—		6,403
Ending balance		**(10,361)**		(15,879)		(14,742)
Loans to officers:						
Beginning balance		**(2)**		(1,832)		(1,973)
Issuance of officer loans and interest, net of payments		**2**		438		(309)
Reclass loans of former officers to other assets		**—**		1,392		450
Ending balance		**—**		(2)		(1,832)
Retained earnings (accumulated deficit):						
Beginning balance		**(102,782)**		(185,961)		606,502
Net income (loss)		**178,870**		85,010		(793,001)
Preferred dividends, net of retirements		**(1,074)**		(1,696)		597
Dividends on common stock		**(19,786)**		—		—
Issuance of treasury stock		**(175)**		(135)		(59)
Ending balance		**55,053**		(102,782)		(185,961)
Treasury stock:						
Beginning balance	**(203,575)**	**(2,391)**	(1,333,264)	(18,704)	(15,097,987)	(364,901)
Issuance of common stock	**—**	**—**	—	—	(5,253,502)	(86,869)
Retirement of common stock	**—**	**—**	—	—	20,301,489	450,904
Acquisition of treasury stock	**—**	**—**	—	—	(1,434,100)	(19,508)
Issuance of treasury stock	**203,575**	**2,391**	1,129,689	16,313	150,836	1,670
Ending balance	**—**	**—**	(203,575)	(2,391)	(1,333,264)	(18,704)
Accumulated other comprehensive income (loss):						
Beginning balance		**(4,577)**		(9,502)		(22,631)
Unrealized gain on marketable securities		**11**		102		—
Unrealized gain on cash flow hedges		**—**		7,727		21,458
Minimum pension liability adjustment		**7,769**		284		(1,341)
Foreign currency translation adjustment		**—**		—		1,044
Income tax expense		**(3,090)**		(3,188)		(8,032)
Ending balance		**113**		(4,577)		(9,502)
Total Shareholders' Equity		**$1,409,322**		$1,036,760		$ 980,640

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

WESTAR ENERGY, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. DESCRIPTION OF BUSINESS

We are the largest electric utility in Kansas. Unless the context otherwise indicates, all references in this Annual Report on Form 10-K to "the company," "we," "us," "our" and similar words are to Westar Energy, Inc. and its consolidated subsidiaries. The term "Westar Energy" refers to Westar Energy, Inc., a Kansas corporation incorporated in 1924, alone and not together with its consolidated subsidiaries. We provide electric generation, transmission and distribution services to approximately 653,000 customers in Kansas. Westar Energy provides these services in central and northeastern Kansas, including the cities of Topeka, Lawrence, Manhattan, Salina and Hutchinson. Kansas Gas and Electric Company (KGE), Westar Energy's wholly owned subsidiary, provides these services in south-central and southeastern Kansas, including the city of Wichita, Kansas. Both Westar Energy and KGE conduct business using the name Westar Energy. Our corporate headquarters is located at 818 South Kansas Avenue, Topeka, Kansas 66612.

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

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation

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

Use of Management's Estimates

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

Regulatory Accounting

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

Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery in customer rates. Regulatory liabilities represent probable obligations to make refunds to customers for previous collections for costs that are not likely to be incurred in the future. Regulatory assets and liabilities reflected on our consolidated balance sheets are as follows.

As of December 31,	2004	2003
	(In Thousands)	
Amounts due from customers for future income taxes, net	$191,597	$207,812
Debt reacquisition costs	45,203	25,155
Deferred employee benefit costs	39,727	18,424
Deferred plant costs	27,979	28,532
2002 ice storm costs	17,774	16,369
Asset retirement obligations	77,349	70,455
KCC depreciation	22,596	14,294
Wolf Creek outage	6,467	13,645
Other regulatory assets	14,252	16,629
Total regulatory assets	$442,944	$411,315
Total regulatory liabilities	$ 29,292	$ 14,323

- **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 accelerated 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 loss on reacquired debt and refinancing costs on the LaCygne 2 generating unit lease. Debt reacquisition costs are amortized over the original term of the reacquired debt or, if refinanced, the term of the new debt.
- **Deferred employee benefit costs:** Employee benefit costs include pension benefit obligations and post-retirement and post-employment expenses.

- **Deferred plant costs:** Deferred plant costs under SFAS No. 90, "Regulated Enterprises — Accounting for Abandonments and Disallowances of Plant Costs," related to the Wolf Creek nuclear generating facility will be recovered over the term of the plant's operating license through 2025.
- **2002 ice storm costs:** We accumulated and deferred for future 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 this asset will be considered during the 2005 rate review.
- **Asset retirement obligations:** Asset retirement obligations represent amounts associated with our legal obligation to retire Wolf Creek. We recover final retirement costs through rates as provided by the Kansas Corporation Commission (KCC). We have placed amounts recovered through rates in a trust. The trust's funds will be used to pay for the costs to retire and decommission Wolf Creek. See Note 16, "Asset Retirement Obligations," for information regarding our Nuclear Decommissioning Trust Fund.
- **KCC depreciation:** Due to the change in our depreciation rates for ratemaking purposes for Wolf Creek and LaCygne 2, we record a regulatory asset for the amount that our depreciation expense exceeds our depreciation costs recovered in rates. See "— Depreciation" for additional information.
- **Wolf Creek outage:** Represents maintenance costs incurred in our most recent refueling outage. In accordance with regulatory treatment, this amount is amortized to expense ratably over the 18-month period after the outage.
- **Other regulatory assets:** This includes various regulatory assets that are relatively small in relation to the total regulatory assets balance. Other regulatory assets include property taxes, coal contract settlement costs, rate review expense, and the net removal component included in depreciation rates.
- **Other regulatory liabilities:** This includes various regulatory liabilities that are relatively small and includes provisions for rate refunds, property taxes, emissions allowances, savings from the sale of an office building and the net removal component included in depreciation rates. Other regulatory liabilities are included in other long-term liabilities on our consolidated balance sheets.

A return is allowed on the KCC depreciation and coal contract settlement costs.

Cash and Cash Equivalents

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

Restricted Cash

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

Inventories and Supplies

Inventories and supplies 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 3.79% in 2004, 5.27% in 2003 and 5.95% in 2002. The cost of additions to utility plant and replacement units of property is capitalized. AFUDC capitalized was $1.8 million in 2004, $1.5 million in 2003 and $2.2 million in 2002.

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 the 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 2.6% during 2004, 2.5% during 2003 and 2.7% during 2002.

Effective April 1, 2002, we adopted new depreciation rates which reduced our annual depreciation expense by approximately $30.0 million.

As part of the 2001 KCC rate order, the KCC extended the estimated retirement date for Wolf Creek from 2025 to 2045, although our operating license for Wolf Creek expires in 2025. The KCC also extended the estimated retirement date for LaCygne 2 to 2032, although the term of our lease for LaCygne 2 expires in 2016. The effect of extending the retirement date was to reduce our depreciation and amortization expense recovered in customer rates. For financial statement purposes, we recognize depreciation and amortization expense based on the current operating license and the lease term. We record a regulatory asset for the difference between the KCC allowed expense and the expense recorded for financial statement purposes.

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

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

Nuclear Fuel

Our share of the cost of nuclear fuel used in the process of refinement, conversion, enrichment and fabrication is recorded as an asset in property, plant and equipment on our consolidated balance sheets at original cost and is amortized to 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 $30.9 million at December 31, 2004 and $16.6 million at December 31, 2003. Spent fuel charged to fuel and purchased power was $19.3 million in 2004, $17.0 million in 2003 and $17.8 million in 2002.

Cash Surrender Value of Life Insurance

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

	2004	2003
	(In Thousands)	
Cash surrender value of policies	$ 967,485	$ 906,118
Borrowings against policies	(891,320)	(834,673)
COLI, net	$ 76,165	$ 71,445

Income is recorded for increases in cash surrender value and net death proceeds. Interest incurred on amounts borrowed is offset against policy income. Income recognized from death proceeds is highly variable from period to period. Death benefits recognized as income on our consolidated statements of income (loss) approximated $2.0 million in 2004, $1.8 million in 2003 and $3.6 million in 2002.

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, 2004, we had estimated unbilled revenue of $47.6 million.

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. Unless related to fuel, we include the net mark-to-market change in sales on our consolidated statements of income (loss). 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 and derivative contracts when such data are available. When market prices are not readily available or determinable, we use alternative approaches, such as model pricing. Prices used to value these transactions reflect our best estimate of fair values of our trading positions. Results actually achieved from these activities could vary materially from intended results and could affect our consolidated financial results.

Income Taxes

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.

Dilutive Shares

Basic earnings (loss) per share applicable to equivalent common stock are based on the weighted average number of common shares outstanding and shares issuable in connection with vested restricted share units (RSUs) during the period reported. Diluted earnings (loss) per share include the effects of potential issuances of common shares resulting from the assumed vesting of all outstanding RSUs, the exercise of all outstanding stock options issued pursuant to the terms of our stock-based compensation plans and the additional issuance of shares under the employee stock purchase plan (ESPP). The dilutive effect of shares under the ESPP, stock-based compensation and stock options is computed using the treasury stock method.

The following table reconciles the weighted average number of common shares outstanding used to compute basic and diluted earnings (loss) per share.

Year Ended December 31,	2004	2003	2002
DENOMINATOR FOR BASIC AND DILUTED EARNINGS PER SHARE:			
Denominator for basic earnings per share — weighted average shares	82,941,374	72,428,728	71,731,580
Effect of dilutive securities:			
Employee stock purchase plan shares	17,515	113,737	11,030
Employee stock options	1,943	305	—
Restricted share awards	680,216	924,978	527,116
Denominator for diluted earnings per share — weighted average shares	83,641,048	73,467,748	72,269,726
Potentially dilutive shares not included in the denominator because they are antidilutive	217,375	217,375	232,638

Stock Based Compensation

For purposes of the pro forma disclosures required by SFAS No. 148, "Accounting for Stock Based Compensation — Transition and Disclosure," the estimated fair value of stock options is amortized to expense over the relevant vesting period. Information related to the pro forma impact on our consolidated earnings (loss) and earnings (loss) per share follows.

	2004	2003	2002
	(Dollars In Thousands, Except Per Share Amounts)		
Earnings (loss) available for common stock, as reported	$177,900	$ 84,042	$(793,400)
Add: Stock-based compensation included in earnings (loss) available for common stock, as reported, net of related tax effects	294	46	1
Deduct: Total stock option expense determined under fair value method for all awards, net of related tax effects	757	2,615	188
Earnings (loss) available for common stock, pro forma	$177,437	$ 81,473	$(793,587)
Weighted average shares used for dilution	83,641,048	73,467,748	72,269,726
Earnings (loss) per share:			
Basic — as reported	$2.14	$1.16	$(11.06)
Basic — pro forma	$2.14	$1.12	$(11.06)
Diluted — as reported	$2.13	$1.14	$(10.98)
Diluted — pro forma	$2.12	$1.11	$(10.98)

Segments of Business

Prior to 2004 we had identified two reportable segments: "Electric Utility" and "Other." Our "Electric Utility" segment consisted of our integrated electric utility operations. "Other" included our former ownership interests in ONEOK, Inc. (ONEOK), Protection One, Inc. and Protection One Europe and other investments that in the aggregate were immaterial to our business or consolidated results of continuing operations.

With the sale of our interests in ONEOK, Protection One Europe and Protection One, we are now a vertically integrated electric utility with a single operating segment. Our chief operating decision maker evaluates our financial performance based on earnings (loss) per share of the entire company. We no longer have a distinction between segments for utility operations and other investments.

Supplemental Cash Flow Information

	2004	2003	2002
		(In Thousands)	
CASH PAID FOR:			
Interest on financing activities, net of amount capitalized	$127,993	$208,174	$218,066
Income taxes	1,162	53,625	510
NON-CASH FINANCING TRANSACTIONS:			
Issuance of stock to subsidiary (See Note 19, "Common and Preferred Stock")	—	—	86,870
Issuance of common stock for reinvested dividends and RSUs	14,674	9,505	23,146
Assets acquired through capital leases	3,272	1,252	6,471

Reclassifications

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

3. RATE MATTERS AND REGULATION

Rate Review Request

As a result of an earlier KCC order, we will file a request for a rate review with the KCC by May 2, 2005, based on a test year consisting of the 12 months ended December 31, 2004.

Current Status of the Debt Reduction Plan

In 2004, we reduced, by $533.4 million, the debt shown on our consolidated balance sheet with internally generated cash, the proceeds received from the sale of Protection One, Inc. (Protection One) and proceeds from an equity offering. Additionally, due to the sale of Protection One in February 2004, we reduced the long-term debt that was included in the liabilities of discontinued operations by $305.2 million.

Electric Service Reliability

On January 16, 2004, the KCC issued an order regarding electric service reliability for retail customers. The order was intended to help the KCC assess the reliability of retail electric service. Specifically, the KCC wanted to establish uniform definitions and requirements regarding service obligations, record keeping, customer notification and methods of reporting results to the KCC. On February 10, 2004, the North American Electric Reliability Council (NERC) issued reliability improvement initiatives stemming from the investigation of the August 14, 2003 blackout in portions of the northeastern United States. These initiatives will impact our operations in a number of ways, including system relay protection, vegetation management and operator training. The NERC and the ten operating regions in the United States, including the Southwest Power Pool, are working together to determine what operating policies and planning standards changes are necessary to achieve the NERC's goals. We are unable to estimate potential compliance costs at this time, it is likely that our annual capital and maintenance expenditure requirements will increase in the future.

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

In 2003, we classified our monitored security businesses as discontinued operations. We also reclassified historical periods to conform with this classification.

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

On February 17, 2004, we closed the sale of our interest in Protection One to subsidiaries of Quadrangle Capital Partners LP and Quadrangle Master Funding Ltd. (together, Quadrangle). At closing, we assigned to Quadrangle the senior credit facility between Westar Industries, Inc., Westar Energy's wholly owned subsidiary, and Protection One, which had an outstanding balance of $215.5 million. At closing, we received proceeds of $122.2 million.

Protection One had been part of our consolidated tax group since 1997. Under the terms of a tax sharing agreement, we have reimbursed Protection One for current tax benefits used in our consolidated tax return attributable to Protection One. On November 12, 2004, we entered into a settlement agreement with Protection One and Quadrangle that, among other things, terminated a tax sharing agreement, settled Protection One's claims with us relating to the tax sharing agreement and settled claims between Quadrangle and us relating to the sale transaction. Pursuant to the terms of the settlement agreement, Quadrangle paid us $32.5 million in cash as additional consideration, and we settled tax sharing-related obligations to Protection One by tendering $27.1 million in Protection One 7-3/8% senior notes, including accrued interest, and paying $45.9 million in cash. Our net cash payment under the settlement agreement was $13.4 million. In addition, the settlement agreement provided that we would jointly agree to make an Internal Revenue Code (IRC) Section 338(h)(10) election. For tax purposes, an IRC Section 338(h)(10) election allows us to treat the sale of Protection One stock as a sale of the assets of Protection One.

Effective January 1, 2002, we adopted SFAS No. 142, "Goodwill and Other Intangible Assets," and SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." SFAS No. 142 established new standards for accounting for goodwill. SFAS No. 142 continued to require the recognition of goodwill as an asset, but discontinued the amortization of goodwill. In addition, annual impairment tests must be performed using a fair-value based approach as opposed to an undiscounted cash flow approach required under prior standards. Upon the completion of the impairment tests as of January 1, 2002, we determined that the carrying values of goodwill at Protection One and Protection One Europe had been impaired and impairment charges were recorded as discussed below.

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

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

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

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

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

Results of discontinued operations are presented in the table below.

Year Ended December 31,	2004	2003	2002
	(In Thousands, Except Per Share Amounts)		
Sales	$ 22,466	$ 306,938	$ 351,499
Costs and expenses	19,937	289,900	754,656
Earnings (loss) from discontinued operations before income taxes	2,529	17,038	(403,157)
Estimated gain (loss) on disposal	30,980	(258,979)	(1,853)
Income tax benefit	(45,281)	(164,036)	(146,910)
Results of discontinued operations before accounting change, net of tax	78,790	(77,905)	(258,100)
Cumulative effect of accounting change, net of tax of $72,335	—	—	(623,717)
Results of discontinued operations	$ 78,790	$ (77,905)	$(881,817)
Basic Earnings (Loss) Per Share:			
Results of discontinued operations, before accounting change	$ 0.95	$ (1.08)	$ (3.60)
Cumulative effect of accounting change, net of tax	—	—	(8.69)
Results of discontinued operations, net of tax	$ 0.95	$ (1.08)	$ (12.29)
Diluted Earnings (Loss) Per Share:			
Results of discontinued operations, before accounting change	$ 0.94	$ (1.06)	$ (3.57)
Cumulative effect of accounting change, net of tax	—	—	(8.63)
Results of discontinued operations, net of tax	$ 0.94	$ (1.06)	$ (12.20)

The major classes of assets and liabilities of the monitored services businesses were as follows.

December 31,	2003
	(In Thousands)
Assets:	
Current	$ 80,850
Property and equipment	60,656
Customer accounts, net	268,533
Goodwill, net	41,847
Other	118,655
Total assets	$ 570,541
Liabilities:	
Current	$ 68,816
Long-term debt	305,234
Other long-term liabilities	101,547
Total liabilities	$ 475,597

5. ACCOUNTS RECEIVABLE AND VARIABLE INTEREST ENTITIES

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

As of December 31,	2004	2003
	(In Thousands)	
Customer accounts receivable	$ 97,017	$ 85,712
Allowance for uncollectable accounts	(5,152)	(5,313)
Transferred receivables, net	91,865	80,399
Other accounts receivable	828	674
Other allowance for uncollectable accounts	(161)	(102)
Accounts receivable, net	$ 92,532	$ 80,971

Accounts Receivable Sales Program

WR Receivables Corporation, a wholly owned subsidiary, has an agreement with a financial institution whereby WR Receivables can sell an interest of up to $125.0 million in a designated pool of our qualified accounts receivable. The agreement expires in July 2005. Under the terms of the agreement, new receivables generated by us are continuously purchased by WR Receivables. The receivables sold to the financial institution are not reflected in the accounts receivable balance in the accompanying consolidated balance sheets. The amounts sold to the financial institution were $80.0 million at December 31, 2004 and 2003.

We service, administer and collect the receivables on behalf of the financial institution. Administrative expenses associated with the sale of these receivables were $2.1 million in 2004, $2.4 million in 2003 and $2.9 million in 2002. We include these expenses in other expense on our consolidated statements of income (loss).

We record receivables transferred to WR Receivables at book value, net of allowances for bad debts. This approximates fair value due to the short-term nature of the receivable. We include the transferred accounts receivables in accounts receivable, net, on our consolidated balance sheets. The interests that we hold are included in the table below.

As of December 31,	2004	2003
	(In Thousands)	
Accounts receivables retained by WR Receivables, net	$ 81,842	$ 71,213
Accounts receivables reserved for purchaser, net	10,023	9,186
Transferred receivables, net	$ 91,865	$ 80,399

The following table provides gross proceeds and repayments between WR Receivables and the financial institution. We record these items on the consolidated statements of cash flows in the accounts receivable, net, line of cash flows from operating activities.

Year Ended December 31,	2004	2003	2002
		(In Thousands)	
Proceeds from the purchaser due to the sale of receivables	$ 40,000	$ —	$ 30,000
Payments to the purchaser for net collection of its receivables	(40,000)	(30,000)	(20,000)
Proceeds and repayments, net	$ —	$ (30,000)	$ 10,000

Consolidation of Variable Interest Entities

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

On December 14, 1995, Western Resources Capital I, a wholly owned trust, issued $100.0 million of 7-7/8% Cumulative Quarterly Income Preferred Securities, Series A. On April 16, 2004, we redeemed our entire issuance of Western Resources Capital I 7-7/8% Cumulative Quarterly Income Preferred Securities, Series A, at par. On July 31, 1996, Western Resources Capital II, a wholly owned trust, issued $120.0 million of 8-1/2% Cumulative Quarterly Income Preferred Securities, Series B. On September 22, 2003, we redeemed our entire issuance of Western Resources Capital II 8-1/2% Cumulative Quarterly Income Preferred Securities, Series B, at par.

Provisions of FIN 46R required the deconsolidation of the Western Resources Capital I trust, which resulted in the amounts previously classified as shares subject to mandatory redemption being reclassified as long-term debt, affiliate on the consolidated balance sheet.

6. FINANCIAL INSTRUMENTS, ENERGY MARKETING AND RISK MANAGEMENT

Values of Financial Instruments

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,	2004	2003	2004	2003
		(In Thousands)		
Fixed-rate debt, net of current maturities[a]	$1,419,406	$1,815,320	$1,530,035	$1,946,053

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

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

The fair value estimates are based on information available at December 31, 2004 and 2003. These fair value estimates have not been comprehensively revalued since that date and current estimates of fair value may differ significantly from the amounts above.

Derivative Instruments and Hedge Accounting

We are exposed to market risks from changes in commodity prices and interest rates that could affect our consolidated results of operations and financial condition. We manage our exposure to these market risks through our regular operating and financing activities and, when deemed appropriate, 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.

We use derivative financial and physical instruments primarily to manage risk as it relates to changes in the prices of commodities including natural gas, oil, coal and electricity. 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 manage our commodity price risk. We trade electricity, coal, natural gas and oil. We use financial instruments, including forward contracts, options and swaps and we trade energy commodity contracts daily. We may also use economic hedging techniques to manage overall fuel expenditures. We procure physical product under forward agreements and spot market transactions.

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. We reflect changes in value on our consolidated statements of income (loss). We believe financial instruments help us manage our contractual commitments, reduce our exposure to changes in cash market prices and take advantage of selected market opportunities. We refer to these transactions as energy 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 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 increased expenses or loss of revenues associated with this could be material and adverse to our consolidated results of operations and financial condition.

We use various fossil fuel types, including coal, natural gas and oil, to operate our 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 the availability, price and deliverability of a given fuel type as well as planned and scheduled outages at our facilities that use fossil fuels and the nuclear refueling schedule. Our customers' electricity usage could also vary from year to year based on weather or other factors.

Although we generally attempt to balance our physical and financial contracts in terms of quantities and contract performance, net open positions typically exist. We will at times create a net open position or allow a net open position to continue when we believe that future price movements will increase the portfolio's value. To the extent we have 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.

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

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

Effective October 4, 2001, we entered into a $500.0 million interest rate swap agreement with a term of two years. At that time, the effect of the swap agreement was to fix the annual interest rate on a term loan at 6.18%. We settled the swap agreement for a nominal amount on September 29, 2003.

In the second quarter of 2003, we purchased a call option at a cost of $65.8 million, which locked in a settlement cost associated with a call option entered into in 1998 related to our 6.25% putable/callable notes. We settled the call option in August 2003.

7. PROPERTY, PLANT AND EQUIPMENT

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

	2004	2003
	(In Thousands)	
Electric plant in service	$ 5,777,519	$ 5,665,479
Electric plant acquisition adjustment	802,318	802,318
Accumulated depreciation	(2,761,781)	(2,647,214)
	3,818,056	3,820,583
Construction work in progress	56,910	59,570
Nuclear fuel, net	35,942	29,198
Net utility plant	3,910,908	3,909,351
Non-utility plant in service	79	149
Net property, plant and equipment	$ 3,910,987	$ 3,909,500

Depreciation expense on property, plant and equipment for the years ended December 31, 2004, 2003 and 2002 was as follows.

	2004	2003	2002
		(In Thousands)	
Utility	$ 148,933	$ 147,015	$ 151,538
Non-utility	—	10	58
Total depreciation expense	$ 148,933	$ 147,025	$ 151,596

8. JOINT OWNERSHIP OF UTILITY PLANTS

Under joint ownership agreements with other utilities, we have undivided ownership interests in four 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, 2004 is shown in the table below.

	Our Ownership at December 31, 2004				
	In-Service Dates	Investment	Accumulated Depreciation	Net MW	Ownership Percent
		(Dollars in Thousands)			
LaCygne 1[a]	June 1973	$ 191,346	$118,168	344.0	50
Jeffrey 1[b]	July 1978	318,211	159,469	618.0	84
Jeffrey 2[b]	May 1980	311,333	142,225	617.0	84
Jeffrey 3[b]	May 1983	415,005	201,283	624.0	84
Jeffrey wind 1[b]	May 1999	874	230	0.6	84
Jeffrey wind 2[b]	May 1999	874	230	0.6	84
Wolf Creek[c]	Sept. 1985	1,409,238	590,055	548.0	47
State Line[d]	June 2001	108,099	15,115	200.0	40

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

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 LaCygne 2 (representing 337 megawatt (MW) capacity) sold and leased back to KGE in 1987, are included in operating expenses on our consolidated statements of income (loss). Our share of other transactions associated with the plants is included in the appropriate classification on our consolidated financial statements.

9. COMMON STOCK ISSUANCE

Westar Energy sold approximately 12.5 million shares of its common stock in 2004 for net proceeds of $245.1 million.

10. SHORT-TERM DEBT

A syndicate of banks provides us a revolving credit facility on a committed basis totaling $300.0 million. The facility is secured by KGE's first mortgage bonds and matures on March 12, 2007. It allows us to borrow up to an aggregate limit of $300.0 million, including letters of credit up to a maximum aggregate amount of $50.0 million. At December 31, 2004, we had no outstanding borrowings and $15.3 million of letters of credit outstanding under the revolving credit facility.

Information regarding our short-term borrowings is as follows.

As of December 31,	2004	2003
	(In Thousands)	
Borrowings outstanding at year end:		
Credit agreement and an other financing arrangement	$ —	$ 1,000
Weighted average interest rate on debt outstanding at year-end, excluding fees	—	6.00%
Weighted average short-term debt outstanding during the year	$1,434	$ 1,009
Weighted daily average interest rates during the year, excluding fees	3.50%	6.12%

Our interest expense on short-term debt was $1.1 million in 2004, $1.2 million in 2003 and $7.4 million in 2002.

11. LONG-TERM DEBT

Outstanding Debt

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

	2004	2003
	(In Thousands)	
Westar Energy		
First mortgage bond series:		
7.875% due 2007	$ 365,000	$ 365,000
6.000% due 2014	250,000	—
8.500% due 2022	—	125,000
7.650% due 2023	—	100,000
	615,000	590,000
Pollution control bond series:		
Variable due 2032, 1.95% at December 31, 2004	45,000	45,000
Variable due 2032, 2.00% at December 31, 2004	30,500	30,500
6.000% due 2033	—	58,340
5.000% due 2033	58,340	—
	133,840	133,840
6.875% unsecured senior notes due 2004	—	184,456
9.750% unsecured senior notes due 2007	260,000	387,000
7.125% unsecured senior notes due 2009	145,078	145,078
6.80% unsecured senior notes due 2018	—	26,993
Senior secured term loan due 2005	—	114,143
Other long-term agreements	—	4,179
	405,078	861,849
KGE		
First mortgage bond series:		
6.500% due 2005	65,000	65,000
6.200% due 2006	100,000	100,000
	165,000	165,000
Pollution control bond series:		
5.100% due 2023	13,488	13,488
Variable due 2027, 1.75% at December 31, 2004	21,940	21,940
7.000% due 2031	—	327,500
5.300% due 2031	108,600	—
5.300% due 2031	18,900	—
2.650% due 2031 and putable 2006	100,000	—
Variable due 2031, 1.92% at December 31, 2004	100,000	—
Variable due 2032, 1.67% at December 31, 2004	14,500	14,500
Variable due 2032, 1.85% at December 31, 2004	10,000	10,000
	387,428	387,428
Unamortized debt discount[(a)]	(1,445)	(3,923)
Long-term debt due within one year	(65,000)	(185,941)
Long-term debt, net	$1,639,901	$1,948,253
Long-term debt, affiliate	$ —	$ 103,093

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

The Westar Energy mortgage and the KGE mortgage each contain provisions restricting the amount of first mortgage bonds that could be issued by each entity. Additionally, Westar Energy's revolving credit facility prohibits us from increasing the amount of secured indebtedness outstanding as of March 12, 2004 by more than $300.0 million. 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 Westar Energy's first mortgage bonds authorized by its Mortgage and Deed of Trust, dated July 1, 1939, as supplemented, is unlimited subject to certain limitations as described below. The amount of KGE's first mortgage bonds authorized by the KGE Mortgage and Deed of Trust, dated April 1, 1940, as supplemented, is limited to a maximum of $2 billion, unless amended. First mortgage bonds are secured by utility assets. Amounts of additional bonds that may be issued are subject to property, earnings and certain restrictive provisions, except in connection with certain refundings, of each mortgage. At December 31, 2004, based on an assumed interest rate of 6%, approximately $210.0 million principal amount of additional first mortgage bonds could be issued under the most restrictive provisions in Westar Energy's mortgage. At December 31, 2004, based on an assumed interest rate of 6%, approximately $874.0 million principal amount of additional KGE first mortgage bonds could be issued under the most restrictive provisions in the mortgage.

Westar Energy's revolving credit facility prohibits us from increasing the amount of secured indebtedness outstanding as of March 12, 2004 by more than $300.0 million. In June 2004, Westar Energy issued $250.0 million of Westar Energy first mortgage bonds and immediately placed the funds in escrow for retirement of $225.0 million of Westar Energy first mortgage bonds, which was completed in July 2004. Therefore, at December 31, 2004, we could incur a maximum of $275.0 million of additional secured debt under this provision in Westar Energy's revolving credit facility. Following Westar Energy's January 18, 2005 issuance of $250.0 million of first mortgage bonds, as discussed below, we can incur a maximum of $25.0 million of additional secured debt under this provision in Westar Energy's revolving credit facility.

During 2004, we recognized a loss of $16.1 million in connection with the redemption of our senior unsecured notes and $2.7 million in connection with the redemption of affiliate long-term debt.

On January 18, 2005, Westar Energy sold $250.0 million aggregate principal amount of Westar Energy first mortgage bonds, consisting of $125.0 million 5.15% bonds maturing in 2017 and $125.0 million 5.95% bonds maturing in 2035. On February 17, 2005, we used the net proceeds from the offering, together with cash on hand, additional funds raised through the accounts receivable conduit facility and borrowings under Westar Energy's revolving credit facility, to redeem the remaining $260.0 million aggregate principal amount of Westar Energy 9.75% senior notes due 2007. Together with accrued interest and a premium equal to approximately 12% of the outstanding senior notes, we paid $298.5 million to redeem the Westar Energy 9.75% senior notes due 2007. After this transaction, we had $10.0 million outstanding under the revolving credit facility and $30.0 million available under the accounts receivable conduit facility.

Debt Covenants

Some of our debt instruments contain restrictions that require us to maintain various coverage and leverage ratios as defined in the agreements. We calculate these ratios in accordance with our credit agreements. These ratios are used solely to determine compliance with our various debt covenants. We were in compliance with these covenants at December 31, 2004.

Maturities

Maturities of long-term debt at December 31, 2004 are as follows.

Year	Principal Amount
	(In Thousands)
2005	$ 65,000
2006	100,000
2007	625,000
2008	—
2009	145,078
Thereafter	769,823
	$1,704,901

Our interest expense on long-term debt was $141.1 million in 2004, $223.2 million in 2003 and $227.8 million in 2002.

Affiliate Long-term Debt and Other Mandatorily Redeemable Securities

On December 14, 1995, Western Resources Capital I, a wholly owned trust, issued $100.0 million of 7-7/8% Cumulative Quarterly Income Preferred Securities, Series A. On April 16, 2004, we redeemed our entire issuance of Western Resources Capital I 7-7/8% Cumulative Quarterly Income Preferred Securities, Series A, at par. This transaction reduced our long-term liabilities by approximately $103.1 million.

On July 31, 1996, Western Resources Capital II, a wholly owned trust, issued $120.0 million of 8-1/2% Cumulative Quarterly Income Preferred Securities, Series B. On September 22, 2003, we redeemed our entire issuance of Western Resources Capital II 8-1/2% Cumulative Quarterly Income Preferred Securities, Series B, at par. This transaction reduced our long-term liabilities by approximately $115.7 million.

12. EMPLOYEE BENEFIT PLANS

Pension

We maintain a qualified non-contributory defined benefit pension plan covering substantially all of our employees. Pension benefits are based on years of service and the employee's compensation during the 60 highest paid consecutive months out of 120 before retirement. Our policy is to fund pension costs accrued, subject to limitations set by the Employee Retirement Income Security Act of 1974 and the Internal Revenue Code. We also maintain a non-qualified Executive Salary Continuation Plan for the benefit of certain current and retired officers. Employees hired after December 31, 2001 are covered by the same defined benefit plan with benefits derived from a cash balance account formula.

As a co-owner of WCNOC, we are indirectly responsible for 47% of the liabilities and expenses associated with the WCNOC pension and post-retirement plans. See Note 13, "WCNOC Employee Benefit Plans" for WCNOC benefit information.

Our 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 our pension liabilities, the fair value of our pension plan assets was less than the accumulated benefit obligation at our measurement dates of December 31, 2004 and December 31, 2003. On March 29, 2004, the Federal Energy Regulatory Commission (FERC) issued guidance allowing an entity to recognize the amount of the minimum pension liability otherwise chargeable to other comprehensive income as a regulatory asset. On January 13, 2005, we received an accounting authority order from the KCC to recognize as a regulatory asset the additional minimum pension liability that otherwise would have been charged to other comprehensive income (OCI). At December 31, 2004, our additional minimum pension liability adjustment was $41.8 million, offset by an intangible asset of $15.9 million and a regulatory asset of $25.9 million. At December 31, 2003, our additional minimum pension liability was $8.7 million, offset by an intangible asset of $0.9 million and OCI of $7.8 million. We accrue the cost of post-retirement benefits during the years an employee provides service. The following tables summarize the status of our pension and other post-retirement benefit plans.

	Pension Benefits		Post-retirement Benefits	
At December 31,	2004	2003	2004	2003
	(In Thousands)			
Change in Benefit Obligation:				
Benefit obligation, beginning of year	$ 469,651	$ 433,620	$ 125,324	$ 124,113
Service cost	6,110	5,381	1,487	1,186
Interest cost	28,319	28,833	6,774	8,004
Plan participants' contributions	—	—	2,695	2,242
Benefits paid	(28,880)	(29,389)	(12,479)	(13,076)
Assumption changes	11,227	27,556	4,461	7,911
Recognition of Medicare Part D	—	—	(3,807)	—
Actuarial losses (gains)	8,050	2,710	(989)	(5,056)
Amendments	138	500	—	—
Curtailments, settlements and special term benefits	—	440	—	—
Benefit obligation, end of year	$ 494,615	$ 469,651	$ 123,466	$ 125,324
Change in Plan Assets:				
Fair value of plan assets, beginning of year	$ 409,932	$ 360,024	$ 22,543	$ 12,629
Adjustments	—	—	—	269
Actual return on plan assets	39,870	77,591	1,802	396
Employer contribution	—	—	17,800	19,800
Plan participants' contributions	—	—	2,695	2,242
Benefits paid	(27,200)	(27,683)	(12,228)	(12,793)
Fair value of plan assets, end of year	$ 422,602	$ 409,932	$ 32,612	$ 22,543
Funded status	$ (72,013)	$ (59,719)	$ (90,854)	$(102,781)
Unrecognized net loss	70,807	55,366	30,424	31,723
Unrecognized transition obligation, net	—	—	31,768	35,699
Unrecognized prior service cost	15,906	18,530	(1,398)	(1,865)
Prepaid (accrued) benefit costs	$ 14,700	$ 14,177	$ (30,060)	$ (37,224)
Amounts Recognized in the Balance Sheets Consist Of:				
Prepaid benefit cost	$ 30,597	$ 28,976	$ N/A	$ N/A
Accrued benefit liability	(15,897)	(14,799)	(30,060)	(37,224)
Additional minimum liability	(41,815)	(8,692)	N/A	N/A
Intangible asset	15,906	923	N/A	N/A
Other comprehensive income[a]	—	7,769	N/A	N/A
Regulatory asset[a]	25,909	—	N/A	N/A
Net amount recognized	$ 14,700	$ 14,177	$ (30,060)	$ (37,224)

[a] *On March 29, 2004, FERC issued guidance allowing an entity to recognize the amount of the minimum pension liability otherwise chargeable to other comprehensive income as a regulatory asset. On January 13, 2005, we received an accounting authority order from the KCC to record the other comprehensive income related to pension benefit obligation costs as a regulatory asset.*

At December 31,	Pension Benefits 2004	Pension Benefits 2003	Post-retirement Benefits 2004	Post-retirement Benefits 2003
	(Dollars in Thousands)			
Accumulated Benefit Obligation	$449,717	$429,852	N/A	N/A
Pension Plans With a Projected Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$494,615	$469,651	N/A	N/A
Accumulated benefit obligation	449,717	429,852	N/A	N/A
Fair value of plan assets	422,602	409,932	N/A	N/A
Pension Plans With an Accumulated Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$494,615	$ 23,613	N/A	N/A
Accumulated benefit obligation	449,717	23,491	N/A	N/A
Fair value of plan assets	422,602	—	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	$123,466	$125,324
Fair value of plan assets	N/A	N/A	32,612	22,543
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Benefit Obligation:				
Discount rate	5.90%	6.10%	5.90%	6.10%
Compensation rate increase	3.00%	3.10%	3.00%	3.10%

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

The prior service cost (benefit) is amortized on a straight-line basis over the average future service of the active employees (plan participants) benefiting under the plan at the time of the amendment. The net actuarial gain (loss) subject to amortization is amortized on a straight-line basis over the average future service of active plan participants benefiting under the plan, without application of the amortization corridor described in SFAS 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 2004	Pension Benefits 2003	Pension Benefits 2002
	(Dollars in Thousands)		
Components of Net Periodic (Benefit) Cost:			
Service cost	$ 6,110	$ 5,381	$ 6,942
Interest cost	28,319	28,833	28,724
Expected return on plan assets	(38,561)	(40,513)	(42,292)
Amortization of unrecognized transition obligation, net	—	(177)	(251)
Amortization of unrecognized prior service costs	2,762	3,358	3,300
Amortization of loss (gain), net	2,525	(2,032)	(5,932)
Curtailments, settlements and special term benefits	—	440	12,589
Net periodic (benefit) cost	$ 1,155	$ (4,710)	$ 3,080
Weighted-Average Actuarial Assumptions used to Determine Net Periodic (Benefit) Cost:			
Discount rate	6.10%	6.75%	7.25%
Expected long-term return on plan assets	9.00%	9.00%	9.00%
Compensation rate increase	3.10%	3.75%	4.25%

For the Year Ended December 31,	Post-retirement Benefits 2004	Post-retirement Benefits 2003	Post-retirement Benefits 2002
	(Dollars in Thousands)		
Components of Net Periodic (Benefit) Cost:			
Service cost	$ 1,487	$ 1,186	$ 1,248
Interest cost	6,774	8,004	7,467
Expected return on plan assets	(1,999)	(1,431)	(52)
Amortization of unrecognized transition obligation, net	3,931	3,931	3,931
Amortization of unrecognized prior service costs	(467)	(467)	(467)
Amortization of loss (gain), net	1,172	1,612	919
Curtailments, settlements and special term benefits	—	—	—
Net periodic (benefit) cost	$10,898	$12,835	$ 13,046
Weighted-Average Actuarial Assumptions used to Determine Net Periodic (Benefit) Cost:			
Discount rate	6.10%	6.75%	7.25%
Expected long-term return on plan assets	8.50%	9.00%	9.00%
Compensation rate increase	3.10%	3.75%	4.25%

The expected long-term rate of return on plan assets is based on historical and projected rates of return for current and planned asset classes in the 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. In selecting the discount rate, fixed income security yield rates for corporate high-grade bond yields are considered.

In December 2003, the Medicare Prescription Drug Improvement and Modernization Act of 2003 (Medicare Act) became law. The Medicare Act introduced a prescription drug benefit under Medicare as well as a federal subsidy beginning in 2006. This subsidy will be paid to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare. We believe our retiree health care benefits plan is at least actuarially equivalent to Medicare and is eligible for the federal subsidy. We adopted the guidance in the third quarter of 2004. Treating the future subsidy under the Medicare Act as an actuarial experience gain, as required by the guidance, decreased the accumulated post-retirement benefit obligation by approximately $4.4 million. The subsidy also decreased the net periodic post-retirement benefit cost by approximately $0.5 million for the year ended December 31, 2004.

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

At December 31,	2004	2003
Health care cost trend rate assumed for next year	8.00%	9.00%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	5.00%	5.00%
Year that the rate reaches the ultimate trend rate	2008	2008

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	$ 113	$ (111)
Effect on post-retirement benefit obligation	1,914	(1,878)

The asset allocation for the pension plans and the post-retirement benefit plans at the end of 2004 and 2003, and the target allocations for 2005 and 2006, by asset category, are as shown in the following table.

	Target Allocations		Plan Assets	
Asset Category	2006	2005	2004	2003
Pension Plans:				
Equity securities	65%	65%	68%	68%
Debt securities	30%	30%	28%	29%
Cash and other	5%	5%	4%	3%
Total			100%	100%
Post-retirement Benefit Plans:				
Equity securities	65%	40%	35%	32%
Debt securities	30%	55%	45%	34%
Cash and other	5%	5%	20%	34%
Total			100%	100%

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

	Pension Benefits		Post-Retirement Benefits	
Expected cash flows:	To/(From) Trust	To/(From) Company Assets	To/(From) Trust	To/(From) Company Assets
		(In Thousands)		
Expected contributions:				
2005	$ —	$ 1,900	$ 18,600	$ 300
Expected benefit payments:				
2005	$ (26,700)	$(1,900)	$ (8,100)	$ (300)
2006	(26,200)	(2,000)	(8,200)	(300)
2007	(26,000)	(1,900)	(8,400)	(300)
2008	(25,800)	(1,800)	(8,400)	(300)
2009	(25,600)	(1,800)	(8,400)	(300)
2010 – 2014	(137,000)	(9,100)	(42,500)	(1,500)

Savings Plans

We maintain a qualified 401(k) savings plan in which most of our employees participate. We match employees' contributions in cash up to specified maximum limits. Our contributions to the plans are deposited with a trustee and are invested at the direction of plan participants into one or more of the investment alternatives we provide under the plan. Our contributions were $3.4 million for 2004, $3.0 million for 2003 and $2.9 million for 2002.

Under our qualified employee stock purchase plan established in 1999, full-time, non-union employees purchase designated shares of our common stock at no more than a 15% discounted price. Our employees purchased 185,016 shares in 2004 at an average price of $17.20 per share. Employees purchased 403,705 shares in 2003 at an average price of $8.45 per share and employees purchased 46,432 shares at an average price of $8.45 per share in 2002. We discontinued this plan effective January 1, 2005.

Stock Based Compensation Plans

We have a long-term incentive and share award plan (LTISA Plan), which is a stock-based compensation plan in which employees and directors are eligible for awards. The LTISA Plan was implemented as a means to attract, retain and motivate employees and directors. Under the LTISA Plan, we may grant awards in the form of stock options, dividend equivalents, share appreciation rights, RSUs, performance shares and performance share units to plan participants. Up to five million shares of common stock may be granted under the LTISA Plan. At December 31, 2004, awards of 3,639,062 shares of common stock had been made under the LTISA Plan. Dividend equivalents accrue on the awarded RSUs. Dividend equivalents are the right to receive cash equal to the value of dividends paid on our common stock.

In December 2004, the FASB issued SFAS No. 123R, "Share-Based Payment: An Amendment of FASB Statements No. 123 and 95." SFAS No. 123R requires companies to recognize as compensation expense the grant-date fair value of stock options and other equity-based compensation issued to employees. The provisions of the statement are effective for financial statements issued for periods that begin after June 15, 2005, which will be our third quarter beginning July 1, 2005. We will use the modified prospective transition method. Under the modified prospective method, awards that are granted, modified or settled after the date of adoption will be measured and accounted for in accordance with SFAS No. 123R. Compensation cost for awards granted prior to, but not vested as of the date SFAS No. 123R is adopted, would be based on the grant date, fair value and attributes originally used to value those awards.

We currently use RSUs for stock-based awards granted to management employees. In addition, we have eliminated our employee stock purchase plan and all outstanding options have vested. Given the characteristics of our stock-based compensation program, we do not expect the adoption of SFAS No. 123R to materially impact our results of operations.

In 2004, we granted 67,051 RSUs to selected management employees and directors. In 2003, we granted 559,095 RSUs to officers, selected management employees and directors. We granted 590,585 RSUs to a broad-based group of over 800 non-union employees and directors in 2002. Each RSU represents a right to receive one share of our common stock at the end of the restricted period assuming certain criteria are met. The unearned compensation related to the grant of RSUs is shown as a separate component of shareholders' equity. Unearned compensation is being amortized to expense over the vesting period. In addition, RSUs linked to 783,400 shares of Protection One common stock and 12,193 shares of Guardian International, Inc. preferred stock held by us were granted to certain current and former officers in 2002.

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

Another component of the LTISA Plan is the Executive Stock for Compensation program, where in the past eligible employees were entitled to receive RSUs in lieu of current cash compensation. The Executive Stock for Compensation program was modified in 2001 to pay a portion of current compensation in the form of stock. Although this plan was discontinued in 2001, dividends will continue to be paid to plan participants on their outstanding plan balance until distribution. At the end of the deferral period, RSUs are paid in the form of stock. Plan participants were awarded 4,422 shares of common stock for dividends in 2004, 10,009 shares in 2003, and 12,121 shares in 2002. Participants received common stock distributions of 46,544 shares in 2004, 5,101shares in 2003 and 40,097 shares in 2002.

Stock options under the LTISA plan are as follows.

As of December 31,	2004		2003		2002	
	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price
	(In Thousands)		(In Thousands)		(In Thousands)	
Outstanding, beginning of year	226.7	$32.92	232.6	$32.08	552.3	$34.02
Exercised	(1.5)	15.31	—	—	(2.6)	18.71
Forfeited	—	—	(5.9)	24.99	(317.1)	35.57
Outstanding, end of year	225.2	32.38	226.7	32.92	232.6	32.08

Stock options issued and outstanding at December 31, 2004 are as follows.

	Range of Exercise Price	Number Issued and Outstanding	Weighted-Average Contractual Life in Years	Weighted-Average Exercise Price
Options — Exercisable:				
2000	$15.3125	7,783	6	$ 15.31
1999	27.8125 - 32.125	22,900	5	29.52
1998	38.625 - 43.125	55,890	4	41.15
1997	30.75	94,490	3	30.75
1996	29.25	44,095	2	29.25
Total outstanding		225,158		

RSUs under the LTISA plan are as follows.

As of December 31,	2004		2003		2002	
	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price
	(In Thousands)		(In Thousands)		(In Thousands)	
Outstanding, beginning of year	1,913.7	$16.25	1,619.9	$18.08	1,902.9	$22.87
Granted	60.1	20.57	547.3	12.90	584.2	13.28
Vested	(668.4)	14.65	(251.8)	14.60	(291.8)	18.81
Forfeited	(7.0)	17.72	(1.7)	17.39	(575.4)	28.70
Outstanding, end of year	1,298.4	17.50	1,913.7	16.25	1,619.9	18.08

RSUs issued and outstanding at December 31, 2004 are as follows.

	Range of Fair Value at Grant Date	Number Issued and Outstanding
Restricted share units:		
2004	$20.45	59,225
2003	11.57 - 13.95	464,731
2002	11.57 - 17.49	180,555
2001	17.67 - 19.61	196,820
2000	15.3125 - 19.875	264,249
1999	27.8130 - 32.125	63,783
1998	38.625	69,000
Total outstanding		1,298,363

We also issued dividend equivalents to recipients of stock options and RSUs. Recipients of RSUs receive dividend equivalents when dividends are paid on shares of company stock. The value of each dividend equivalent related to stock options is calculated by accumulating dividends that would have been paid or payable on a share of company common stock. The dividend equivalents, with respect to stock options, expire after nine years from date of grant. The weighted-average fair value at the grant-date of the dividend equivalents on stock options was $6.40 in 2004, $6.38 in 2003 and $6.35 in 2002.

13. WCNOC EMPLOYEE BENEFIT PLANS

Pension and Post-retirement Benefits

The WCNOC 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 WCNOC's pension plan assets was less than the accumulated benefit obligation at the measurement dates. On March 29, 2004, the FERC issued guidance allowing an entity to recognize the amount of the minimum pension liability otherwise chargeable to other comprehensive income as a regulatory asset. On January 13, 2005, we received an accounting authority order from the KCC to recognize as a regulatory asset the additional minimum pension liability that otherwise would have been charged to other comprehensive income. At December 31, 2004, our share of WCNOC's additional minimum pension liability adjustment was $3.1 million, offset by an intangible asset of $0.6 million and a regulatory asset of $2.5 million. At December 31, 2003, our share of WCNOC's additional minimum pension liability was immaterial.

As a co-owner of WCNOC, we are indirectly responsible for 47% of the liabilities and expenses associated with the WCNOC pension and post-retirement plans. We accrue our 47% of the WCNOC cost of pension and post-retirement benefits during the years an employee provides service. Our 47% share is included in the tables that follow.

	Pension Benefits		Post-retirement Benefits	
At December 31,	**2004**	**2003**	**2004**	**2003**
	(In Thousands)			
Change in Benefit Obligation:				
Benefit obligation, beginning of year	$ 49,927	$ 44,519	$ 5,455	$ 4,857
Service cost	2,572	2,545	235	218
Interest cost	3,295	2,928	356	289
Plan participants' contributions	—	—	147	111
Benefits paid	(849)	(729)	(416)	(349)
Actuarial losses	4,223	664	325	329
Benefit obligation, end of year	$ 59,168	$ 49,927	$ 6,102	$ 5,455
Change in Plan Assets:				
Fair value of plan assets, beginning of year	$ 26,799	$ 22,276	$ N/A	$ N/A
Actual return on plan assets	2,551	2,622	N/A	N/A
Employer contribution	3,810	2,459	N/A	N/A
Benefits paid	(669)	(558)	N/A	N/A
Fair value of plan assets, end of year	$ 32,491	$ 26,799	$ N/A	$ N/A
Funded status	$ (26,677)	$ (23,128)	$ (6,102)	$ (5,455)
Unrecognized net loss	15,239	11,589	2,211	2,028
Unrecognized transition obligation, net	398	455	461	519
Unrecognized prior service cost	220	252	—	—
Post-measurement date adjustments	740	441	—	—
Accrued post-retirement benefit costs	$ (10,080)	$ (10,391)	$ (3,430)	$ (2,908)
Amounts Recognized in the Balance Sheets Consist Of:				
Accrued benefit liability	$ (10,080)	$ (10,391)	$ (3,430)	$ (2,908)
Additional minimum liability	(3,144)	(66)	N/A	N/A
Intangible asset	618	35	N/A	N/A
Other comprehensive income[a]	—	31	N/A	N/A
Regulatory asset[a]	2,526	—	N/A	N/A
Net amount recognized	$ (10,080)	$ (10,391)	$ (3,430)	$ (2,908)

[a] *On March 29, 2004, FERC issued guidance allowing an entity to recognize the amount of the minimum pension liability otherwise chargeable to other comprehensive income as a regulatory asset. On January 13, 2005, we received an accounting authority order from the KCC to record the other comprehensive income related to pension benefit obligation costs as a regulatory asset.*

	Pension Benefits		Post-retirement Benefits	
At December 31,	**2004**	**2003**	**2004**	**2003**
	(Dollars in Thousands)			
Accumulated Benefit Obligation	$ 46,455	$ 37,037	N/A	N/A
Pension Plans With a Projected Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$ 59,168	$ 49,927	N/A	N/A
Accumulated benefit obligation	46,455	37,037	N/A	N/A
Fair value of plan assets	32,491	26,799	N/A	N/A
Pension Plans With an Accumulated Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$ 59,168	$ 49,927	N/A	N/A
Accumulated benefit obligation	46,455	37,037	N/A	N/A
Fair value of plan assets	32,491	26,799	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	$ 6,060	$ 5,455
Fair value of plan assets	N/A	N/A	N/A	N/A
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Benefit Obligation:				
Discount rate	6.00%	6.20%	6.00%	6.20%
Compensation rate increase	3.00%	3.20%	N/A	N/A

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

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

	Pension Benefits		
For the Year Ended December 31,	**2004**	**2003**	**2002**
	(Dollars in Thousands)		
Components of Net Periodic Cost:			
Service cost	$ 2,572	$ 2,545	$ 2,207
Interest cost	3,295	2,928	2,613
Expected return on plan assets	(2,780)	(2,464)	(2,469)
Amortization of unrecognized:			
Transition obligation, net	57	57	57
Prior service costs	31	31	27
Loss, net	802	603	21
Curtailments, settlements and special term benefits	—	—	284
Net periodic cost	$ 3,977	$ 3,700	$ 2,740
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost:			
Discount rate	6.20%	6.75%	7.25%
Expected long-term return on plan assets	9.00%	9.00%	9.02%
Compensation rate increase	3.20%	Graded rates	Graded rates

For the Year Ended December 31,	Post-retirement Benefits 2004	2003	2002
	(Dollars in Thousands)		
Components of Net Periodic Cost:			
Service cost	$ 235	$ 218	$ 166
Interest cost	356	289	272
Expected return on plan assets	—	—	—
Amortization of unrecognized:			
Transition obligation, net	58	58	57
Prior service costs	—	—	—
Loss, net	141	99	73
Curtailments, settlements and special term benefits	—	—	—
Net periodic cost	$ 790	$ 664	$ 568
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost:			
Discount rate	6.10%	6.50%	7.25%
Expected long-term return on plan assets	8.50%	N/A	N/A
Compensation rate increase	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. In selecting the discount rate, fixed income security yield rates for corporate high-grade bond yields are considered.

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

At December 31,	2004	2003
Health care cost trend rate assumed for next year	8.5%	9.0%
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	$ 3	$ (3)
Effect on the present value of the accumulated projected benefit obligation	46	(45)

The asset allocation for the pension plans at the end of 2004 and 2003, and the target allocation for 2005, by asset category are as shown in the following table.

Asset Category	Target Allocation for 2005	Plan Assets 2004	2003
Pension Plans:			
Equity securities	50% - 70%	65%	66%
Debt securities	30% - 50%	28%	33%
Other	0%	7%	1%
Total		100%	100%

WCNOC's pension plan investment strategy supports the objective of the fund, which is to earn the highest possible return on plan assets consistent with a reasonable and prudent level of risk. Investments are diversified across classes, sectors and manager style to minimize the risk of large losses. WCNOC delegates investment management to specialists in each asset class and where appropriate, provides the investment manager with specific guidelines, which include allowable and/or prohibited investment types. Investment risk is measured and monitored on an ongoing basis through quarterly investment portfolio reviews.

Expected cash flows:	Pension Benefits To/(From) Trust	Pension Benefits To/(From) Company Assets	Post-Retirement Benefits To/(From) Trust	Post-Retirement Benefits To/(From) Company Assets
	(In Thousands)			
Expected contributions:				
2005	$ 4,700	$ 200	$ N/A	$ 300
Expected benefit payments:				
2005	$ (800)	$ (200)	$ N/A	$ (300)
2006	(900)	(200)	N/A	(300)
2007	(1,100)	(200)	N/A	(300)
2008	(1,400)	(200)	N/A	(400)
2009	(1,600)	(200)	N/A	(400)
2010 – 2014	(13,800)	(900)	N/A	(2,600)

Savings Plan

WCNOC 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. WCNOC's contribution to the plan is deposited with a trustee and is invested at the direction of plan participants into one or more of the investment alternatives provided under the plan. Our portion of expense associated with WCNOC's matching contributions was $0.8 million for 2004, $0.9 million for 2003 and $0.8 million for 2002.

14. INCOME TAXES

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

	2004	2003	2002
	(In Thousands)		
Current income taxes:			
Federal	$ 41,649	$ 148,117	$ (41,115)
State	(2,991)	33,926	(5,515)
Deferred income taxes:			
Federal	(2,285)	(78,069)	31,014
State	1,858	(17,564)	8,890
Investment tax credit amortization	(4,788)	(4,642)	(4,793)
Total income tax expense (benefit) as reported before discontinued operations and cumulative effect of accounting change	33,443	81,768	(11,519)
Income tax expense (benefit) from discontinued operations:			
Discontinued operations	(45,281)	(164,036)	(146,910)
Cumulative effect of accounting change	—	—	(72,335)
Total income tax benefit	$ (11,838)	$ (82,268)	$(230,764)

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

December 31,	2004	2003
	(In Thousands)	
Current deferred tax assets, net	$ 7,218	$ 123,256
Non-current deferred tax liabilities, net	927,087	969,544
Net deferred tax liabilities	$ 919,869	$ 846,288

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

December 31,	2004	2003
	(In Thousands)	
Deferred tax assets:		
Deferred gain on sale-leaseback	$ 61,241	$ 66,448
General business credit carryforward[(a)]	27,645	27,524
Accrued liabilities	18,803	19,599
Disallowed plant costs	13,484	14,527
Long-term energy contracts	11,194	12,034
Protection One impairment	—	327,665
Capital loss carryforward[(b)]	230,226	—
Other	74,875	69,074
Total gross deferred tax assets	437,468	536,871
Less: Valuation allowance[(b)]	236,588	236,214
Deferred tax assets	$ 200,880	$ 300,657
Deferred tax liabilities:		
Accelerated depreciation	$ 659,776	$ 666,315
Acquisition premium	243,165	251,163
Amounts due from customers for future income taxes, net	191,597	207,812
Other	26,211	21,655
Total deferred tax liabilities	$1,120,749	$1,146,945
Net deferred tax liabilities	$ 919,869	$ 846,288

[(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 2024.*

[(b)] *We have a net capital loss of $839.6 million available to offset past and future capital gains. The capital loss can be carried back to offset 2003 capital gains (limited to the amount of 2003 taxable income). Any excess capital loss is available for carry forward through 2009. However, as we do not expect to realize any significant capital gains in the future, a valuation allowance of $230.2 million has been established. In addition, a valuation allowance of $6.4 million has been established for certain deferred tax assets related to the write-down of investments.*

In accordance with various rate orders, we have reduced rates to reflect the tax benefits associated with certain accelerated 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. This liability is classified above as amounts due from customers for future income taxes.

The effective income tax rates set forth below are for continuing operations. The rates 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,	2004	2003	2002
Statutory federal income tax rate	35.0 %	35.0 %	35.0 %
Effect of:			
State income taxes	1.0	4.3	2.8
Amortization of investment tax credits	(3.6)	(1.9)	(6.2)
Corporate-owned life insurance policies	(9.0)	(5.0)	(15.0)
Accelerated depreciation flow through and amortization	5.3	2.2	6.4
Dividends received deduction	—	(1.7)	(12.6)
Income tax reserve adjustment	(5.3)	—	(27.4)
Capital loss utilization	(2.2)	—	—
Other	3.8	0.5	2.1
Effective income tax rate	25.0 %	33.4 %	(14.9)%

As of December 31, 2004 and 2003, we had recorded reserves for uncertain tax positions, including interest, of $49.7 million and $55.6 million, respectively. During 2004, we reduced this reserve by $5.9 million due to a re-evaluation of estimates based on expected settlements and the finalization of the sale of Protection One. Tax reserves are established for tax deductions or income positions taken in prior income tax returns that we believe were treated properly on the tax returns but may be challenged if such tax returns are audited. The tax returns containing these tax deductions or income positions are currently under audit or will likely be audited. The timing of the resolution of these audits is uncertain. If the positions taken on the returns are ultimately sustained, we will reverse these tax provisions to income. If the positions taken on the tax returns are not ultimately sustained, we may be required to make cash payments plus interest. We also have a tax reserve of $4.3 million (after-tax) for property and sales tax assessments by various state and local taxing authorities.

15. 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 $159.4 million at December 31, 2004, of which $34.6 million has been committed. The $34.6 million commitment relates to purchase obligations issued and outstanding at year-end.

The yearly detail of the aggregate amount of required payments at December 31, 2004 was as follows.

	Committed Amount
	(In Thousands)
2005	$28,601
2006	3,668
2007	2,343
	$34,612

Clean Air Act

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

EPA New Source Review

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

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

We are in discussions with the EPA concerning this matter in an attempt to reach a settlement. We expect that any settlement with the EPA could require us to update or install emissions controls at Jeffrey Energy Center over an agreed upon number of years. Additionally, we might be required to update or install emissions controls at our other coal-fired plants, pay fines or penalties, or take other remedial action. Together, these costs could be material. The EPA has informed us 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 rates. If we were to reach a settlement with the EPA, we may be assessed a penalty. The penalty could be material and may not be recovered in rates.

Manufactured Gas Sites

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

We and the Kansas Department of Health and Environment (KDHE) entered into a consent agreement in 1994 governing all future work at the Kansas sites. Under the terms of the consent agreement, we agreed to investigate and remediate, if necessary, these sites. Through December 31, 2004, the costs incurred for preliminary site investigation and risk assessment have been minimal. Pursuant to an environmental indemnity agreement with ONEOK, the current owner of some of the Kansas sites, our liability for twelve of the Kansas sites is limited. Of those twelve sites, ONEOK assumed total liability for remediation of seven sites and we share liability for remediation with ONEOK for five sites. Our total liability for the five shared sites is capped at $3.8 million and terminates in 2012. We have sole responsibility for remediation with respect to three Kansas sites. With respect to two of those sites, we are currently either conducting or completing remediation activities and, with respect to the third site, we will begin investigation activities in the near future.

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

Solid Waste Landfills

We operate solid waste landfills at Jeffrey, Lawrence and Tecumseh Energy Centers for the single purpose of disposing of coal combustion waste material. Additionally, there is one retired landfill at each of the Lawrence and Neosho Energy Centers. All landfills are permitted by the KDHE. The operating landfill at Lawrence Energy Center is projected to be full by late 2007 or early 2008 requiring us to permit and construct a new landfill at this site. We began the process of obtaining this permit in late 2003. We will continue to work with the appropriate regulatory agencies to ensure that the new landfill and expansion of the existing landfill will meet the operating requirements of the Lawrence Energy Center.

Nuclear Decommissioning

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

We expense nuclear decommissioning costs over the expected life of Wolf Creek. The amount we expense is based on an estimate of nuclear decommissioning costs that we will incur upon retirement of the plant. Nuclear decommissioning costs that are recovered in rates are deposited in an external trust fund. In 2004, we expensed approximately $3.9 million for nuclear decommissioning. We record our investment in the nuclear decommissioning fund at fair value. Fair value approximated $91.1 million at December 31, 2004 and $80.1 million at December 31, 2003.

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 for the pro rata share of the plant.

We filed an updated nuclear decommissioning and dismantlement cost estimate with the KCC on August 30, 2002. Estimated costs outlined by this study were developed to decommission Wolf

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

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

We charge nuclear decommissioning costs to operating expense in accordance with the July 25, 2001 KCC rate order as modified by the KCC's approval of the funding schedule in the KCC's October 13, 2003 order. Electric rates charged to customers provide for recovery of these nuclear decommissioning costs over the life of Wolf Creek, 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.

Storage of Spent Nuclear Fuel

Under the Nuclear Waste Policy Act of 1982, the Department of Energy (DOE) is responsible for the permanent disposal of spent nuclear fuel. As required by federal law, the WCNOC co-owners entered into a standard contract with the DOE in 1984 in which the DOE promised to begin accepting from commercial nuclear power plants their used nuclear fuel for disposal beginning in early 1998. In return, Wolf Creek pays into a federal Nuclear Waste Fund administered by the DOE a quarterly fee for the future disposal of spent nuclear fuel. The fee is one-tenth of a cent for each kilowatt-hour of net nuclear generation produced. We include these disposal costs in operating expenses.

A permanent disposal site will not be available for the nuclear industry until 2012 or later. Under current DOE policy, once a permanent site is available, the DOE will accept spent nuclear fuel on a priority basis. The owners of the oldest spent fuel will be given the highest priority. As a result, disposal services for Wolf Creek will not be available prior to 2018. Wolf Creek has on-site temporary storage for spent nuclear fuel. In early 2000, Wolf Creek completed replacement of spent fuel storage racks to increase its on-site storage capacity for all spent fuel expected to be generated by Wolf Creek through the end of its licensed life in 2025.

In 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. The DOE expects that this facility will open in 2012. However, 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.

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, 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 $10.0 million per incident per year. This assessment is subject to an inflation adjustment based on the Consumer Price Index and applicable premium taxes. This assessment also applies in excess of our worker radiation claims insurance. In addition, Congress could impose additional revenue-raising measures to pay claims. If the $10.8 billion liability limitation is insufficient, Congress will consider taking whatever action is necessary to compensate the public for valid claims.

The Price-Anderson Act expired in August 2002 but was extended until December 31, 2003 for Licensees. Licensees such as Wolf Creek continue to be grandfathered under the Act. The current version of a comprehensive energy bill expected to be adopted in 2005 by Congress contains provisions that would amend Federal Law (the "Price-Anderson Act") addressing public liability from nuclear energy hazards in ways that would increase the annual limit on retrospective assessments from $10.0 million to $15.0 million per reactor per incident.

Nuclear Property Insurance

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

Accidental Nuclear Outage Insurance

The owners also carry additional insurance with NEIL to cover costs of replacement power and other extra expenses incurred during a prolonged outage resulting from accidental property damage at Wolf Creek. If significant losses were incurred at any of the nuclear plants insured under the NEIL policies, we may be subject to retrospective assessments under the current policies of approximately $26.0 million (our share is $12.2 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, 2004, our share of WCNOC's nuclear fuel commitments were approximately $13.5 million for uranium concentrates expiring in 2007, $1.7 million for conversion expiring in 2007, $8.6 million for enrichment expiring at various times through 2006 and $52.4 million for fabrication through 2024.

At December 31, 2004, our coal and coal transportation contract commitments in 2004 dollars under the remaining terms of the contracts were approximately $1.5 billion. The largest contract expires in 2020, with the remaining contracts expiring at various times through 2013.

At December 31, 2004, our natural gas transportation commitments in 2004 dollars under the remaining terms of the contracts were approximately $43.5 million. The natural gas transportation contracts provide firm service to several of our natural gas burning facilities and expire at various times through 2010, except for one contract that expires in 2016.

Energy Act

As part of the 1992 Energy Policy Act, a special assessment is being collected from utilities for a uranium enrichment decontamination and nuclear decommissioning fund. Our portion of the assessment, including carrying costs, for Wolf Creek is approximately $11.1 million, adjusted for inflation. To date, we have paid approximately $9.7 million, with the estimated remainder payable over the next two years. We recover such costs from prices we charge our customers.

16. ASSET RETIREMENT OBLIGATIONS

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

Legal Liability — Wolf Creek

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

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

As of December 31,	2004
	(In Thousands)
Beginning asset retirement obligation	$80,695
Accretion expense	6,423
Ending asset retirement obligation	$87,118

Non-legal Liability — Cost of Removal

We have recovered amounts in rates to provide for recovery of the probable costs of removing utility plant assets, but which do not represent legal retirement obligations. At December 31, 2004, Westar Energy had $1.3 million in removal costs classified as a regulatory asset and KGE had $2.6 million in removal costs classified as a regulatory liability. At December 31, 2003, we had $6.6 million in removal costs classified as a regulatory asset. The net amount related to non-legal retirement costs can fluctuate based on amounts related to removal costs recovered compared to removal costs incurred.

17. LEGAL PROCEEDINGS

We and certain of our present and former officers are defendants in a consolidated purported class action lawsuit in United States District Court in Topeka, Kansas, "In Re Westar Energy, Inc.

Securities Litigation," Master File No. 5:03-CV-4003 and related cases. Plaintiffs filed a Consolidated Amended Complaint on July 15, 2003. The lawsuit is brought on behalf of purchasers of our common stock between March 29, 2000, the date we announced our intention to separate our electric utility operations from our unregulated businesses, and November 8, 2002, the date the KCC issued an order prohibiting the separation. The lawsuit alleges that we violated federal securities laws by making material misrepresentations or omitting material facts concerning the purpose and benefits of the previously proposed separation of our electric utility operations from our unregulated businesses, the compensation of our senior management and the independence and functioning of our board of directors, and that as a result we artificially inflated the price of our common stock. On August 26, 2004, the court issued an order granting a joint motion of all parties requesting a stay of the lawsuit until December 7, 2004, pending efforts to settle the lawsuit through mediation. The court also denied without prejudice motions to dismiss the lawsuit filed by us and other defendants. The court stated its intention to set aside the order upon notice by any party that mediation efforts were unsuccessful, in which case the court would address the motions to dismiss the lawsuit. The stay was subsequently extended to March 18, 2005. We intend to vigorously defend against this action. We are unable to predict the ultimate impact of this matter on our consolidated financial position, results of operations and cash flows.

We and certain of our present and former officers and employees are defendants in a consolidated purported class action lawsuit filed in United States District Court in Topeka, Kansas, "In Re Westar Energy ERISA Litigation, Master File No. 03-4032-JAR." Plaintiffs filed a Consolidated Amended complaint on October 20, 2003. The lawsuit is brought on behalf of participants in, and beneficiaries of, our Employees' 401(k) Savings Plan between July 1, 1998 and January 1, 2003. The lawsuit alleges violations of the Employee Retirement Income Security Act arising from the conduct of certain present and former officers and employees who served or are serving as fiduciaries for the plan. The conduct is related to alleged securities law violations related to the previously proposed separation of our electric utility operations from our unregulated businesses, our rate reviews filed with the KCC in 2000, the compensation of and benefits provided to our senior management, energy marketing transactions with Cleco Corporation and the first and second quarter 2002 restatements of our consolidated financial statements related to the revised goodwill impairment charge and the mark-to-market charge on our putable/callable notes. On August 26, 2004, the court issued an order granting a joint motion of all parties requesting a stay of the lawsuit until December 7, 2004, pending efforts to settle the lawsuit through mediation. The court also denied without prejudice motions to dismiss the lawsuit filed by us and other defendants. The court stated its intention to set aside the order upon notice by any party that mediation efforts were unsuccessful, in which case the court would address the motions to dismiss the lawsuit. The stay was extended to February 8, 2005. On February 8, 2005, the court held a conference at which the parties notified the court that efforts to settle the lawsuit through mediation had not been successful. The court then issued an order renewing the previously filed motions to dismiss and set a scheduling conference on March 8, 2005 to address the scope and timing of discovery in the lawsuit. We intend to vigorously defend against this action. We are unable to predict the ultimate impact of this matter on our consolidated financial position, results of operations and cash flows.

Certain present and former members of our board of directors and officers are defendants in a shareholder derivative complaint filed April 18, 2003, "Mark Epstein vs David C. Wittig, Douglas T. Lake, Charles Q. Chandler IV, Frank J. Becker, Gene A. Budig, John C. Nettels, Jr., Roy A. Edwards, John C. Dicus, Carl M. Koupal, Jr., Larry D. Irick and Cleco Corporation, defendants, and Westar Energy, Inc., nominal defendant, Case No. 03-4081-JAR." Plaintiffs filed an amended shareholder derivative complaint on July 30, 2003. Among other things, the lawsuit claims that the defendants (i) breached fiduciary duties owed to us because of the actions and omissions described in the report of the special committee of our board of directors, (ii) caused or permitted our assets to be wasted on perquisites for certain insiders and (iii) caused or permitted our May 6, 2002 proxy statement to be issued with materially false and misleading statements. The plaintiffs seek unspecified monetary damages and other equitable relief. In October 2003, our board of directors appointed a special litigation committee of the board to evaluate the amended shareholder derivative complaint. The members of the committee were Mollie H. Carter, Arthur B. Krause and Michael F. Morrissey. On August 26, 2004, the court issued an order granting a joint motion of all parties requesting a stay of the lawsuit until December 7, 2004, pending efforts to settle the lawsuit through mediation. The stay was subsequently extended to March 18, 2005. Plaintiffs have informed us they intend to file a motion seeking leave to amend the amended consolidated complaint if the mediation efforts are unsuccessful. The court would then set a date for us, and other defendants who have not already filed a response to the complaint, to respond to the amended complaint. We are unable to predict the ultimate impact of this matter on our consolidated financial position, results of operations and cash flows.

On June 13, 2003, we filed a demand for arbitration with the American Arbitration Association asserting claims against David C. Wittig, our former president, chief executive officer and chairman, and Douglas T. Lake, our former executive vice president, chief strategic officer and member of the board, arising out of their previous employment with us. Mr. Wittig and Mr. Lake have filed counterclaims against us in the arbitration alleging substantial damages related to the termination of their employment and the publication of the report of the special committee of our board of directors. We intend to vigorously defend against these claims. The arbitration has been stayed pending the completion of a trial scheduled to begin May 9, 2005, of Mr. Wittig and Mr. Lake on criminal charges in U.S. District Court in the District of Kansas. We are unable to predict the ultimate impact of this matter on our consolidated financial position, results of operations and cash flows.

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

See also Notes 3, 15, 18 and 20 for discussion of KCC regulatory proceedings, alleged violations of the Clean Air Act, an investigation by the United States Attorney's Office, an inquiry by the Securities and Exchange Commission (SEC), an investigation by FERC and potential liabilities to Mr. Wittig and Mr. Lake.

18. ONGOING INVESTIGATIONS

Grand Jury Subpoena

On September 17, 2002, we were served with a federal grand jury subpoena by the United States Attorney's Office in Topeka, Kansas, requesting information concerning the use of aircraft and our annual shareholder meetings. Since that date, the United States Attorney's Office has served additional subpoenas on us and certain of our employees requesting further information concerning the use of our aircraft; executive compensation arrangements with Mr. Wittig, Mr. Lake and other former and present officers; the proposed rights offering of Westar Industries stock that was abandoned; and the company in general. We are providing information in response to these requests and we are cooperating fully in the investigation. We have not been informed that we are a target of the investigation. On December 4, 2003, Mr. Wittig and Mr. Lake were indicted by the federal grand jury on conspiracy, fraud and other criminal charges related to their actions while serving as our officers. The trial on these charges was held in 2004 and ended with a mistrial. A new trial is scheduled to begin on May 9, 2005. We are unable to predict the ultimate outcome of the investigation or its impact on us.

Securities and Exchange Commission Inquiry

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

FERC Subpoena

On December 16, 2002, we received a subpoena from FERC seeking details on power trades with Cleco Corporation and its affiliates, documents concerning power transactions between our system and our marketing operations and information on power trades in which we or other trading companies acted as intermediaries. We have provided information to FERC in response to the original subpoena, subsequent requests submitted through our counsel and additional subpoenas received July 28, 2003 and October 27, 2003 seeking information about compliance with FERC codes of conduct applicable to generation and transmission activities. We believe that our participation in these transactions and the conduct of our generation and transmission operations did not violate FERC rules and regulations. However, we are unable to predict the ultimate outcome of the investigation.

Department of Labor Investigation

On February 1, 2005, we received a subpoena from the Department of Labor seeking documents related to our Employees' 401(k) Savings Plan and our defined benefit pension plan. At this time, we do not know the specific purpose of the investigation and we are unable to predict the ultimate outcome of the investigation or its impact on us. See Note 17, "Legal Proceedings," for discussion of a class action lawsuit brought on behalf of participants in our Employees' 401(k) Savings Plan.

19. COMMON AND PREFERRED STOCK

Westar Energy's articles of incorporation, as amended, provide for 150,000,000 authorized shares of common stock. At December 31, 2004, we had 86,029,721 shares issued and outstanding.

Westar Energy has a direct stock purchase plan (DSPP). Shares sold pursuant to the DSPP may be either original issue shares or shares purchased in the open market. During 2004, a total of 1,318,079 shares were issued by Westar Energy for the DSPP, the employee stock purchase plan and other stock based plans operated under the 1996 Long-Term Incentive and Share Award Plan. At December 31, 2004, a total of 5,412,096 shares were available under the DSPP registration statement.

Treasury Stock

At December 31, 2004, Westar Energy did not have any treasury stock. At December 31, 2003, Westar Energy had a treasury stock balance of 203,575 shares.

Preferred Stock Not Subject to Mandatory Redemption

Westar Energy's cumulative preferred stock is redeemable in whole or in part on 30 to 60 days' notice at our option. The table below shows our redemption amount for all series of preferred stock not subject to mandatory redemption at December 31, 2004.

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

The provisions of Westar Energy's articles of incorporation, as amended, contain restrictions on the payment of dividends or the making of other distributions on our common stock while any preferred shares remain outstanding unless certain capitalization ratios and other conditions are met. If the ratio of the capital represented by our preference stock and common stock (together, Subordinated Stock), including premiums on our capital stock and its surplus accounts, to its total capital and its surplus accounts at the end of the second month immediately preceding the date of the proposed payment of dividends, adjusted to reflect the proposed payment (Capitalization Ratio), will be less than 20%, then the payment of the dividends on Subordinated Stock shall not exceed 50% of net income available for dividends for the 12-month period ending with and including the second month immediately preceding the date of the proposed payment. If the Capitalization Ratio is 20% or more but less than 25%, then the payment of dividends on the Subordinated Stock, including the proposed payment, shall not exceed 75% of its net income available for dividends for such 12-month period. Except to the extent permitted above, no payment or other distribution may be made that would reduce the Capitalization Ratio to less than 25%. The Capitalization Ratio is determined based on the unconsolidated balance sheet for Westar Energy. At December 31, 2004, the Capitalization Ratio was greater than 25%.

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

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

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

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

At December 31, 2004, we had accrued liabilities totaling approximately $57.8 million for compensation not yet paid to Mr. Wittig and Mr. Lake under various plans. The compensation includes RSU awards, deferred vested shares, deferred RSU awards, deferred vested stock for compensation, executive salary continuation plan benefits and, in the case of Mr. Wittig, benefits arising from a split dollar life insurance agreement. The amount of our obligation to Mr. Wittig related to a split dollar life insurance agreement is subject to adjustment at the end of each quarter based on the total return to our shareholders from the date of that agreement. The total return considers the change in stock price and accumulated dividends. These compensation-related accruals are included in long-term liabilities on the consolidated balance sheets with a portion recorded as a component of paid in capital. The amount accrued will increase annually as it relates to future dividends on deferred RSU awards and increases in amounts that may be due under the executive salary continuation plan.

In addition, we accrued $4.2 million at December 31, 2004 for legal fees and expenses incurred by Mr. Wittig and Mr. Lake that are recorded in accounts payable on our consolidated balance sheets. We will likely incur substantial additional expenses for legal fees and expenses incurred by Mr. Wittig and Mr. Lake related to the arbitration proceeding discussed above, the defense of the criminal charges filed by the United States Attorney's Office in Topeka, Kansas, against Mr. Wittig and Mr. Lake, and the legal proceedings described in Note 17, "Legal Proceedings," above. We are unable to estimate the amount of the additional legal fees and expenses that will be incurred by Mr. Wittig and Mr. Lake for which we may be ultimately responsible. We are also currently unable to determine the amount of the fees which may be recovered under any applicable directors and officers liability insurance policies.

In addition to these amounts, we could also be obligated to make payments to Mr. Wittig and Mr. Lake pursuant to the executive salary continuation plan. Assuming an expected payout period of 35 years, the aggregate nominal amount of these payments would be approximately $16.6 million for Mr. Wittig and $8.3 million for Mr. Lake.

21. REDEMPTION OF GUARDIAN INTERNATIONAL PREFERRED STOCK

On July 9, 2004, Guardian International, Inc. (Guardian) redeemed 8,397 shares of Guardian Series C preferred stock held of record by us. The redemption price was $8.6 million, representing the par value of $1,000 per share, or $8.4 million, plus $0.2 million in accrued dividends through the date of redemption and the redemption premium. In 2002, we granted certain current and former officers 540 RSUs linked to these securities. In 2002, we also transferred beneficial ownership of 4,714 shares of Guardian Series C preferred stock to Mr. Wittig and Mr. Lake in exchange for other securities. The ownership of these shares and related dividends is disputed and is the subject of the arbitration proceeding with Mr. Wittig and Mr. Lake discussed above in Note 17, "Legal Proceedings." We recorded an approximate $0.6 million increase in the balance of our potential liability to Mr. Wittig and Mr. Lake in the third quarter to reflect the difference between the carrying value of the 4,714 shares claimed by Mr. Wittig and Mr. Lake and the redemption amount.

22. MARKETABLE SECURITIES

On January 1, 2003, we classified our investment in ONEOK as an available-for-sale security. During 2003, we sold our investment in ONEOK and recorded a pre-tax gain of $99.3 million. The following table summarizes our marketable security sales for the years ended December 31, 2004, 2003 and 2002.

	2004	2003	2002
		(In Thousands)	
Marketable Security Sales			
Sales proceeds	$ —	$801,841	$ —
Realized gains	—	99,327	—

23. LEASES

Operating Leases

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

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

Year Ended December 31,	LaCygne 2 Lease[a]	Total Operating Leases
	(In Thousands)	
Rental expense:		
2002	$ 28,895	$ 46,312
2003	28,895	42,495
2004	28,895	38,793
Future commitments:		
2005	$ 38,013	$ 49,422
2006	42,287	53,239
2007	78,268	86,802
2008	12,609	20,343
2009	42,287	48,802
Thereafter	289,154	355,290
Total future commitments	$502,618	$613,898

[a] *The LaCygne 2 lease amounts are included in the total operating leases column.*

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

Capital Leases

Capital leases are identified based on the requirements set forth in SFAS No. 13, "Accounting for Leases." For both vehicles and computer equipment, new leases are signed each month based on the terms of the master lease agreement. The lease term for vehicles is from 5 to 14 years depending on the type of vehicle. The computer equipment has either a 2- or 3-year term. Assets recorded under capital leases are listed below.

December 31,	2004	2003
	(In Thousands)	
Vehicles	$35,769	$40,018
Computer equipment and software	2,145	1,118
Accumulated amortization	(17,848)	(18,543)
	$20,066	$22,593

Capital lease payments are currently treated as operating leases for rate making purposes. Minimum annual rental payments, excluding administrative costs such as property taxes, insurance and maintenance, under capital leases at December 31, 2004 are listed below.

Year Ended December 31,	Total Capital Leases
	(In Thousands)
2005	$ 5,267
2006	4,545
2007	4,024
2008	3,284
2009	2,619
Thereafter	4,462
	24,201
Amounts representing imputed interest	(4,135)
Present value of net minimum lease payments under capital leases	$20,066

24. RELATED PARTY TRANSACTIONS — ONEOK Shared Services Agreement

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

	2004	2003	2002
		(In Thousands)	
Charges to ONEOK	$7,213	$8,312	$8,357
Charges from ONEOK	2,735	3,190	3,324

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, we plan to continue to share some facilities and a mobile communications system.

25. WORK FORCE REDUCTIONS – 2002 Voluntary Separation

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

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

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

26. QUARTERLY RESULTS (UNAUDITED)

Our electric business is seasonal in nature and, in our opinion, comparisons between the quarters of a year do not give a true indication of overall trends and changes in operations. In addition, our net results of discontinued operations varied between comparable quarters. In the first quarter of 2003, we classified our monitored security business as discontinued operations requiring the recognition of certain tax benefits resulting in net income from discontinued operations of $103.8 million. In the third quarter of 2003, we wrote down our monitored security business to our estimate of realizable value resulting in a net loss of $161.7 million. In the fourth quarter of 2004, we recognized income from discontinued operations of $71.9 million, which reflects the results of the final settlement of all issues related to the sale of our monitored security business.

	First	Second	Third	Fourth
	(In Thousands, Except Per Share Amounts)			
2004				
Sales	$340,263	$358,430	$421,489	$344,307
Income from continuing operations	8,791	13,979	60,369	16,941
Results of discontinued operations, net of tax	6,888	—	—	71,902
Net income	15,679	13,979	60,369	88,843
Earnings available for common stock	$ 15,437	$ 13,737	$ 60,127	$ 88,599
Per Share Data[(a)]:				
Basic:				
Earnings available from continuing operations	$ 0.12	$ 0.16	$ 0.70	$ 0.19
Discontinued operations, net of tax	0.09	—	—	0.84
Earnings available	$ 0.21	$ 0.16	$ 0.70	$ 1.03
Diluted:				
Earnings available from continuing operations	$ 0.12	$ 0.16	$ 0.69	$ 0.19
Discontinued operations, net of tax	0.09	—	—	0.83
Earnings available	$ 0.21	$ 0.16	$ 0.69	$ 1.02
Cash dividend declared per common share	$ 0.19	$ 0.19	$ 0.19	$ 0.23
Market price per common share:				
High	$ 21.00	$ 21.47	$ 21.11	$ 22.92
Low	$ 18.06	$ 18.24	$ 19.58	$ 20.05

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

	First	Second	Third	Fourth
	(In Thousands, Except Per Share Amounts)			
2003				
Sales	$345,434	$345,885	$438,167	$331,657
Income from continuing operations	20,102	21,807	80,584	40,422
Results of discontinued operations, net of tax	103,822	6,378	(161,651)	(26,454)
Net income (loss)	123,924	28,185	(81,067)	13,968
Earnings (loss) available for common stock	$123,697	$ 27,943	$ (81,283)	$ 13,686
Per Share Data[(a)]:				
Basic:				
Earnings available from continuing operations	$ 0.28	$ 0.30	$ 1.11	$ 0.56
Discontinued operations, net of tax	1.44	0.09	(2.23)	(0.37)
Earnings (loss) available	$ 1.72	$ 0.39	$ (1.12)	$ 0.19
Diluted:				
Earnings available from continuing operations	$ 0.27	$ 0.30	$ 1.09	$ 0.54
Discontinued operations, net of tax	1.44	0.08	(2.20)	(0.35)
Earnings (loss) available	$ 1.71	$ 0.38	$ (1.11)	$ 0.19
Cash dividend declared per common share	$ 0.19	$ 0.19	$ 0.19	$ 0.19
Market price per common share:				
High	$ 13.04	$ 17.09	$ 18.65	$ 20.49
Low	$ 9.76	$ 12.15	$ 15.45	$ 18.40

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

27. SUBSEQUENT EVENT — ICE STORM

On January 4 and 5, 2005, substantially all of our service territory experienced a severe ice storm. The storm interrupted electric service in a large portion of our service territory and damaged a significant portion of our electric distribution system. We estimate that we will incur $38.0 million to $42.0 million of system restoration costs. Of this amount, we expect $6.0 million to $8.0 million to be accounted for as capital expenditures and we expect the balance related to maintenance expenditures to be accounted for as a regulatory asset. On February 3, 2005, we filed an application for an accounting authority order with the KCC requesting that we be allowed to accumulate and defer for future recovery maintenance costs related to system restoration. We can provide no assurance that the KCC will approve our application, however, in the past the KCC has approved similar requests.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Under the supervision and with the participation of our management, including our chief executive officer and our chief financial officer, we have evaluated the effectiveness of the design and operation of our disclosure controls and procedures as defined in Rule 13a-15(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 chief executive officer and our chief financial officer concluded that, at December 31, 2004, 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, 2004, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

See Item 8. Financial Statements and Supplementary Data for Management's Annual Report On Internal Control Over Financial Reporting and the Independent Registered Public Accounting Firm's report with respect to management's assessment of the effectiveness of internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The information concerning directors required by Item 401 of Regulation S-K will be included under the caption "Election of Directors" in our definitive Proxy Statement for our 2005 Annual Meeting of Shareholders to be filed pursuant to Regulation 14A (the 2005 Proxy Statement), and that information is incorporated by reference in this Form 10-K. Information concerning executive officers required by Item 401 of Regulation S-K is located under Part I, Item 1 of this Form 10-K. The information required by Item 405 of Regulation S-K concerning compliance with Section 16(a) of the Exchange Act will be included under the caption "Section 16(a) Beneficial Ownership Reporting Compliance" in our 2005 Proxy Statement, and that information is incorporated by reference in this Form 10-K. The information required by Item 406 of Regulation S-K will be included under the caption "Corporate Governance Matters" in our 2005 Proxy Statement, and that information is incorporated by reference in this Form 10-K.

ITEM 11. EXECUTIVE COMPENSATION

The information required by Item 11 will be set forth in our 2005 Proxy Statement under the captions "Compensation of Directors," "Compensation of Executive Officers" and "Employment Contracts," and that information is incorporated by reference in this Form 10-K.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The information required by Item 12 will be set forth in our 2005 Proxy Statement under the captions "Beneficial Ownership of Voting Securities" and "Equity Compensation Plan Information," and that information is incorporated by reference in this Form 10-K.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Not applicable.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by Item 14 will be set forth in our 2005 Proxy Statement under the captions "Audit Fees" and "Audit Committee Pre-Approval Policies and Procedures," and that information is incorporated by reference in this Form 10-K.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

FINANCIAL STATEMENTS INCLUDED HEREIN

Westar Energy, Inc.

Report of Independent Registered Public Accounting Firm

Consolidated Balance Sheets, as of December 31, 2004 and 2003

Consolidated Statements of Income (Loss) for the years ended December 31, 2004, 2003 and 2002

Consolidated Statements of Comprehensive Income (Loss) for the years ended December 31, 2004, 2003 and 2002

Consolidated Statements of Cash Flows for the years ended December 31, 2004, 2003 and 2002

Consolidated Statements of Shareholders' Equity for the years ended December 31, 2004, 2003 and 2002

Notes to Consolidated Financial Statements

SCHEDULES

Schedule II —Valuation and Qualifying Accounts

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

EXHIBIT INDEX

All exhibits marked "I" are incorporated herein by reference. All exhibits marked by an asterisk are management contracts or compensatory plans or arrangements required to be identified by Item 14(a)(3) of Form 10-K. All exhibits marked "#" are filed with this Form 10-K.

Description

1(a)	— Underwriting Agreement between Westar Energy, Inc., and Citigroup Global Markets Inc. and Lehman Brothers Inc., as representatives of the several underwriters, dated January 12, 2005 (filed as Exhibit 1.1 to the January 18, 2005 Form 8-K)	I
3(a)	— By-laws of Westar Energy, Inc., as amended April 28, 2004 (filed as Exhibit 3(a) to June 30, 2004 Form 10-Q)	I
3(b)	— Restated Articles of Incorporation of Westar Energy, Inc., as amended through May 25, 1988 (filed as Exhibit 4 to Registration Statement, SEC File No. 33-23022)	I
3(c)	— Certificate of Amendment to Restated Articles of Incorporation of Westar Energy, Inc. dated March 29, 1991	I
3(d)	— Certificate of Designations for Preference Stock, 8.5% Series, without par value, dated March 31, 1991 (filed as Exhibit 3(d) to December 1993 Form 10-K)	I
3(e)	— Certificate of Correction to Restated Articles of Incorporation of Westar Energy, Inc. dated December 20, 1991 (filed as Exhibit 3(b) to December 1991 Form 10-K)	I
3(f)	— Certificate of Designations for Preference Stock, 7.58% Series, without par value, dated April 8, 1992, (filed as Exhibit 3(e) to December 1993 Form 10-K)	I
3(g)	— Certificate of Amendment to Restated Articles of Incorporation of Westar Energy, Inc. dated May 8, 1992 (filed as Exhibit 3(c) to December 31, 1994 Form 10-K)	I
3(h)	— Certificate of Amendment to Restated Articles of Incorporation of Westar Energy, Inc. dated May 26, 1994 (filed as Exhibit 3 to June 1994 Form 10-Q)	I
3(i)	— Certificate of Amendment to Restated Articles of Incorporation of Westar Energy, Inc. dated May 14, 1996 (filed as Exhibit 3(a) to June 1996 Form 10-Q)	I
3(j)	— Certificate of Amendment to Restated Articles of Incorporation of Westar Energy, Inc. dated May 12, 1998 (filed as Exhibit 3 to March 1998 Form 10-Q)	I
3(k)	— Form of Certificate of Designations for 7.5% Convertible Preference Stock (filed as Exhibit 99.4 to November 17, 2000 Form 8-K)	I
3(l)	— Certificate of Amendment to Restated Articles of Incorporation of Westar Energy, Inc. dated July 21, 1999 (filed as Exhibit 3(l) to the December 31, 2002 Form 10-K)	I

3(m)	— Certificate of Amendment to Restated Articles of Incorporation of Westar Energy, Inc. dated June 19, 2002 (filed as Exhibit 3(m) to the December 31, 2002 Form 10-K)	I
4(a)	— Mortgage and Deed of Trust dated July 1, 1939 between Westar Energy, Inc. and Harris Trust and Savings Bank, Trustee (filed as Exhibit 4(a) to Registration Statement No. 33-21739)	I
4(b)	— First and Second Supplemental Indentures dated July 1, 1939 and April 1, 1949, respectively (filed as Exhibit 4(b) to Registration Statement No. 33-21739)	I
4(c)	— Sixth Supplemental Indenture dated October 4, 1951 (filed as Exhibit 4(b) to Registration Statement No. 33-21739)	I
4(d)	— Fourteenth Supplemental Indenture dated May 1, 1976 (filed as Exhibit 4(b) to Registration Statement No. 33-21739)	I
4(e)	— Twenty-Eighth Supplemental Indenture dated July 1, 1992 (filed as Exhibit 4(o) to the December 1992 Form 10-K)	I
4(f)	— Twenty-Ninth Supplemental Indenture dated August 20, 1992 (filed as Exhibit 4(p) to the December 1992 Form 10-K)	I
4(g)	— Thirtieth Supplemental Indenture dated February 1, 1993 (filed as Exhibit 4(q) to the December 1992 Form 10-K)	I
4(h)	— Thirty-First Supplemental Indenture dated April 15, 1993 (filed as Exhibit 4(r) to Registration Statement No. 33-50069)	I
4(i)	— Thirty-Second Supplemental Indenture dated April 15, 1994 (filed as Exhibit 4(s) to the December 31, 1994 Form 10-K)	I
4(j)	— Thirty-Fourth Supplemental Indenture dated June 28, 2000 (filed as Exhibit 4(v) to the December 31, 2000 Form 10-K)	I
4(k)	— Thirty-Fifth Supplemental Indenture dated May 10, 2002 between Westar Energy, Inc. and BNY Midwest Trust Company, as Trustee (filed as Exhibit 4.1 to the March 31, 2002 Form 10-Q)	I
4(l)	— Thirty-Sixth Supplemental Indenture dated as of June 1, 2004, between Westar Energy, Inc. and BNY Midwest Trust Company (as successor to Harris Trust and Savings Bank), to its Mortgage and Deed of Trust dated July 1, 1939 (filed as Exhibit 4.1 to the January 18, 2005 Form 8-K)	I
4(m)	— Thirty-Seventh Supplemental Indenture, dated as of June 17, 2004, between Westar Energy, Inc. and BNY Midwest Trust Company (as successor to Harris Trust and Savings Bank), to its Mortgage and Deed of Trust dated July 1, 1939 (filed as Exhibit 4.2 to the January 18, 2005 Form 8-K)	I
4(n)	— Thirty-Eighth Supplemental Indenture, dated as of January 18, 2005, between Westar Energy, Inc. and BNY Midwest Trust Company (as successor to Harris Trust and Savings Bank), to its Mortgage and Deed of Trust dated July 1, 1939 (filed as Exhibit 4.3 to the January 18, 2005 Form 8-K)	I
4(o)	— Forty-First Supplemental Indenture dated June 6, 2002 between Kansas Gas and Electric Company and BNY Midwest Trust Company, as Trustee (filed as Exhibit 4.1 to the June 30, 2002 Form 10-Q)	I
4(p)	— Forty-Second Supplemental Indenture dated March 12, 2004 between Kansas Gas and Electric Company and BNY Midwest Trust Company, as Trustee	#
4(q)	— Debt Securities Indenture dated August 1, 1998 (filed as Exhibit 4.1 to the June 30, 1998 Form 10-Q)	I
4(r)	— Securities Resolution No. 2 dated as of May 10, 2002 under Indenture dated as of August 1, 1998 between Western Resources, Inc. and Deutsche Bank Trust Company Americas (filed as Exhibit 4.2 to the March 31, 2002 Form 10-Q)	I

Instruments defining the rights of holders of other long-term debt not required to be filed as Exhibits will be furnished to the Commission upon request.

10(a)	— Long-Term Incentive and Share Award Plan (filed as Exhibit 10(a) to the June 1996 Form 10-Q)*	I
10(b)	— Form of Employment Agreements with Messers. Lake and Wittig (filed as Exhibit 10(b) to the December 31, 2000 Form 10-K)*	I
10(c)	— A Rail Transportation Agreement among Burlington Northern Railroad Company, the Union Pacific Railroad Company and Westar Energy, Inc. (filed as Exhibit 10 to the June 1994 Form 10-Q)	I
10(d)	— Agreement between Westar Energy, Inc. and AMAX Coal West Inc. effective March 31, 1993 (filed as Exhibit 10(a) to the December 31, 1993 Form 10-K)	I
10(e)	— Agreement between Westar Energy, Inc. and Williams Natural Gas Company dated October 1, 1993 (filed as Exhibit 10(b) to the December 31, 1993 Form 10-K)	I

10(f)	— Short-term Incentive Plan (filed as Exhibit 10(k) to the December 31, 1993 Form 10-K)*	I
10(g)	— Westar Energy, Inc. Non-Employee Director Deferred Compensation Plan, as amended and restated, dated as of October 20, 2004 (filed as Exhibit 10(l) to the October 20, 2004 Form 8-K)*	I
10(h)	— Executive Salary Continuation Plan of Western Resources, Inc., as revised, effective September 22, 1995 (filed as Exhibit 10(j) to the December 31, 1995 Form 10-K)*	I
10(i)	— Letter Agreement between Westar Energy, Inc. and David C. Wittig, dated April 27, 1995 (filed as Exhibit 10(m) to the December 31, 1995 Form 10-K)*	I
10(j)	— Form of Split Dollar Insurance Agreement (filed as Exhibit 10.3 to the June 30, 1998 Form 10-Q)*	I
10(k)	— Amendment to Letter Agreement between Westar Energy, Inc. and David C. Wittig, dated April 27, 1995 (filed as Exhibit 10 to the June 30, 1998 Form 10-Q/A)*	I
10(l)	— Letter Agreement between Westar Energy, Inc. and Douglas T. Lake, dated August 17, 1998 (filed as Exhibit 10(n) to the December 31, 1999 Form 10-K)*	I
10(m)	— Form of Change of Control Agreement with officers of Westar Energy, Inc. (filed as Exhibit 10(o) to the December 31, 2000 Form 10-K)*	I
10(n)	— Form of loan agreement with officers of Westar Energy, Inc. (filed as Exhibit 10(r) to the December 31, 2001 Form 10-K)*	I
10(o)	— Amendment to Employment Agreement dated April 1, 2002 between Westar Energy, Inc. and David C. Wittig (filed as Exhibit 10.1 to the June 30, 2002 Form 10-Q)*	I
10(p)	— Amendment to Employment Agreement dated April 1, 2002 between Westar Energy and Douglas T. Lake (filed as Exhibit 10.2 to the June 30, 2002 Form 10-Q)*	I
10(q)	— Credit Agreement dated as of June 6, 2002 among Westar Energy, Inc., the lenders from time to time party there to, JPMorgan Chase Bank, as Administrative Agent, Citibank, N.A., as Syndication Agent, and Bank of America, N.A., as Documentation Agent (filed as Exhibit 10.3 to the June 30, 2002 Form 10-Q)	I
10(r)	— Employment Agreement dated September 23, 2002 between Westar Energy, Inc. and David C. Wittig (filed as Exhibit 10.1 to the September 30, 2002 Form 10-Q)*	I
10(s)	— Employment Agreement dated September 23, 2002 between Westar Energy, Inc. and Douglas T. Lake (filed as Exhibit 10.1 to the November 25, 2002 Form 8-K)*	I
10(t)	— Letter Agreement dated November 1, 2003 between Westar Energy, Inc. and James S. Haines, Jr. (filed as Exhibit 10(a) to the September 30, 2003 Form 10-Q)*	I
10(u)	— Letter Agreement dated November 1, 2003 between Westar Energy, Inc. and William B. Moore (filed as Exhibit 10(b) to the September 30, 2003 Form 10-Q)*	I
10(v)	— Letter Agreement dated November 1, 2003 between Westar Energy, Inc. and Mark A. Ruelle (filed as Exhibit 10(c) to the September 30, 2003 Form 10-Q)*	I
10(w)	— Letter Agreement dated November 1, 2003 between Westar Energy, Inc. and Douglas R. Sterbenz (filed as Exhibit 10(d) to the September 30, 2003 Form 10-Q)*	I
10(x)	— Letter Agreement dated November 1, 2003 between Westar Energy, Inc. and Larry D. Irick (filed as Exhibit 10(e) to the September 30, 2003 Form 10-Q)*	I
10(y)	— Waiver and Amendment, dated as of November 6, 2003, to the Credit Agreement, dated as of June 6, 2002, among Westar Energy, Inc., the Lenders from time to time party thereto, JPMorgan Chase Bank, as Administrative Agent for the Lenders, Citibank, N.A., as Syndication Agent, and Bank of America, N.A., as Documentation Agent (filed as Exhibit 10(f) to the September 30, 2003 Form 10-Q)	I
10(z)	— Credit Agreement dated as of March 12, 2004 among Westar Energy, Inc., the several banks and other financial institutions or entities from time to time parties to the Agreement, JPMorgan Chase Bank, as administrative agent, The Bank of New York, as syndication agent, and Citibank, N.A., Union Bank of California, N.A., and Wachovia Bank, National Association, as documentation agents (filed as Exhibit 10(a) to the March 31, 2004 Form 10-Q)	I
10(aa)	— Supplements and modifications to Credit Agreement dated as of March 12, 2004 among Westar Energy, Inc., as Borrower, the Several Lenders Party Thereto, JPMorgan Chase Bank, as Administrative Agent, The Bank of New York, as Syndication Agent, and Citibank, N.A., Union Bank of California, N.A., and Wachovia Bank, national Association, as Documentation Agents (filed as Exhibit 10(a) to the June 30, 2004 Form 10-Q)	I
10(ab)	— Purchase Agreement dated as of December 23, 2003 between POI Acquisition, L.L.C., Westar Industries, Inc. and Westar Energy, Inc. (filed as Exhibit 99.2 to the December 24, 2003 Form 8-K)	I

10(ac)	—	Settlement Agreement dated November 12, 2004 by and among Westar Energy, Inc., Protection One, Inc., POI Acquisition, L.L.C., and POI Acquisition I, Inc. (filed as Exhibit 10.1 to the November 15, 2004 Form 8-K)	I
10(ad)	—	Restricted Share Unit Award Agreement between Westar Energy, Inc. and James S. Haines, Jr. (filed as Exhibit 10.1 to the December 7, 2004 Form 8-K)	I
10(ae)	—	Deferral Election Form of James S. Haines, Jr. (filed as Exhibit 10.2 to the December 7, 2004 Form 8-K)	I
10(af)	—	Resolutions of the Westar Energy, Inc. Board of Directors regarding Non-Employee Director Compensation, approved on September 2, 2004 (filed as Exhibit 10.2 to the December 7, 2004 Form 8-K)	I
10(ag)	—	Restricted Share Unit Award Agreement between Westar Energy, Inc. and William B. Moore (filed as Exhibit 10.1 to the December 29, 2004 Form 8-K)	I
10(ah)	—	Deferral Election Form of William B. Moore (filed as Exhibit 10.2 to the December 29, 2004 Form 8-K)	I
12	—	Computations of Ratio of Consolidated Earnings to Fixed Charges	#
21	—	Subsidiaries of the Registrant	#
23	—	Consent of Independent Registered Public Accounting Firm, Deloitte & Touche LLP	#
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)	—	Kansas Corporation Commission Order dated November 8, 2002 (filed as Exhibit 99.2 to the September 30, 2002 Form 10-Q)	I
99(b)	—	Kansas Corporation Commission Order dated December 23, 2002 (filed as Exhibit 99.1 to the December 27, 2002 Form 8-K)	I
99(c)	—	Debt Reduction and Restructuring Plan filed with the Kansas Corporation Commission on February 6, 2003 (filed as Exhibit 99.1 to the February 6, 2003 Form 8-K)	I
99(d)	—	Kansas Corporation Commission Order dated February 10, 2003 (filed as Exhibit 99.1 to the February 11, 2003 Form 8-K)	I
99(e)	—	Kansas Corporation Commission Order dated March 11, 2003 (filed as Exhibit 99(f) to the December 31, 2002 Form 10-K)	I
99(f)	—	Demand for Arbitration (filed as Exhibit 99.1 to the June 13, 2003 Form 8-K)	I
99(g)	—	Stipulation and Agreement filed with the Kansas Corporation Commission on July 21, 2003 (filed as Exhibit 99.1 to the July 22, 2003 Form 8-K)	I

WESTAR ENERGY, INC.

SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS

Description	Balance at Beginning of Period	Charged to Costs and Expenses	Deductions	Balance at End of Period
		(In Thousands)		
Year ended December 31, 2002				
Allowances deducted from assets for doubtful accounts[a]	$6,825	$6,266	$(6,473)	$6,618
Accrued exit fees, shut-down and severance costs[b]	43	(43)	—	—
Year ended December 31, 2003				
Allowances deducted from assets for doubtful accounts[a]	6,618	3,874	(5,077)	5,415
Accrued exit fees, shut-down and severance costs	—	—	—	—
Year ended December 31, 2004				
Allowances deducted from assets for doubtful accounts	5,415	2,718	(2,820)	5,313
Accrued exit fees, shut-down and severance costs	—	—	—	—

[a] *Deductions are the result of write-offs of accounts receivable.*

[b] *Deductions are the result of payment of accrued severance costs.*

SIGNATURE

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

WESTAR ENERGY, INC.

Date: March 16, 2005

By: /s/ MARK A. RUELLE

Mark A. Ruelle,
Executive Vice President and Chief Financial Officer

SIGNATURES

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

Signature	Title	Date
/s/ JAMES S. HAINES, JR. (James S. Haines, Jr.)	Director, Chief Executive Officer and President (Principal Executive Officer)	March 16, 2005
/s/ MARK A. RUELLE (Mark A. Ruelle)	Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	March 16, 2005
/s/ CHARLES Q. CHANDLER IV (Charles Q. Chandler IV)	Chairman of the Board	March 16, 2005
/s/ MOLLIE HALE CARTER (Mollie Hale Carter)	Director	March 16, 2005
/s/ R. A. EDWARDS III (R. A. Edwards III)	Director	March 16, 2005
/s/ JERRY B. FARLEY (Jerry B. Farley)	Director	March 16, 2005
/s/ B. ANTHONY ISAAC (B. Anthony Isaac)	Director	March 16, 2005
/s/ ARTHUR B. KRAUSE (Arthur B. Krause)	Director	March 16, 2005
/s/ SANDRA A. J. LAWRENCE (Sandra A. J. Lawrence)	Director	March 16, 2005
/s/ MICHAEL F. MORRISSEY (Michael F. Morrissey)	Director	March 16, 2005
/s/ JOHN C. NETTELS, JR. (John C. Nettels, Jr.)	Director	March 16, 2005

SHAREHOLDER INFORMATION & ASSISTANCE

Westar Energy's Shareholder Services department offers personalized service to the company's individual shareholders. We are the transfer agent for Westar Energy common and preferred stock. Shareholder Services provides information and assistance to shareholders regarding:

- Dividend payments
  - Historically paid on the first business day of January, April, July and October
- Direct deposit of dividends
- Transfer of shares
- Lost stock certificates assistance
- Direct Stock Purchase Plan assistance
  - Dividend reinvestment
  - Purchase additional shares by making optional cash payments by check or monthly electronic withdrawal from your bank account
  - Deposit your stock certificates into the plan for safekeeping
  - Sell shares

Please contact us in writing to request elimination of duplicate mailings because of stock registered in more than one way. Mailing of annual reports can be eliminated by marking your proxy card to consent to accessing reports electronically on the Internet.

Please visit our Web site at **www.wr.com.** Registered shareholders can easily access their shareholder account information online by going to **Investor Relations** and clicking on **My Shareholder Account.**

CONTACTING SHAREHOLDER SERVICES

TELEPHONE

Toll-free:	(800) 527-2495
In the Topeka area:	(785) 575-6394
Fax:	(785) 575-1796

ADDRESS

Westar Energy, Inc.
Shareholder Services
P.O. Box 750320
Topeka, KS 66675-0320

E-MAIL ADDRESS

sharsvcs@wr.com

Please include a daytime telephone number in all correspondence.

CO-TRANSFER AGENT

Continental Stock Transfer & Trust Company
17 Battery Place, 8th Floor
New York, NY 10004

CONTACTING INVESTOR RELATIONS

TELEPHONE: (785) 575-1898

ADDRESS

Westar Energy, Inc.
Investor Relations
P.O. Box 889
Topeka, KS 66601-0889

E-MAIL ADDRESS: investrel@wr.com

Copies our Annual Report on Form 10-K that was filed with the Securities and Exchange Commission and other published reports can be obtained without charge by contacting Investor Relations at the above address, by accessing the company's home page on the Internet at www.wr.com or by accessing the Securities and Exchange Commission's Internet Web site at www.sec.gov.

TRUSTEE FOR FIRST MORTGAGE BONDS

PRINCIPAL TRUSTEE, PAYING AGENT AND REGISTRAR

The Bank of New York
2 North LaSalle Street, Suite 1020
Chicago, IL 60602-3802
(800) 548-5075

CORPORATE INFORMATION

CORPORATE ADDRESS

Westar Energy, Inc.
818 South Kansas Avenue
Topeka, KS 66612-1203
(785) 575-6300
www.wr.com

COMMON STOCK LISTING

Ticker Symbol (NYSE): WR

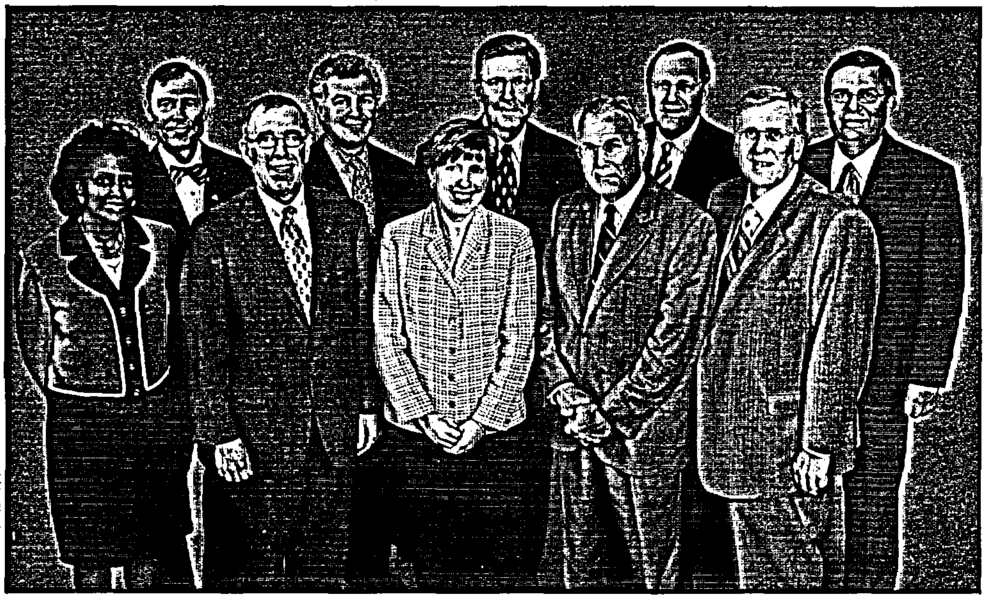
Daily Stock Table Listing: WestarEngy

CHIEF EXECUTIVE OFFICER AND CHIEF FINANCIAL OFFICER CERTIFICATIONS

In 2004, our chief executive officer submitted a certificate to the New York Stock Exchange (NYSE) affirming that he is not aware of any violation by the company of the NYSE's corporate governance listing standards. Our chief executive officer's and chief financial officer's certifications pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 for the year ended December 31, 2004 were included as exhibits to Westar Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31 that was filed with the Securities and Exchange Commission.

This report was printed on recycled paper using soy-based inks.

DIRECTORS



Westar Energy Board of Directors, from left, is composed of Sandra A.J. Lawrence, Jerry B. Farley, Charles Q. Chandler IV, B. Anthony Isaac, Mollie H. Carter, John C. Nettels Jr., James S. Haines Jr., R.A. Edwards, Michael F. Morrissey and Arthur B. Krause.

CHARLES Q. CHANDLER IV (51)
Chairman of the Board
Director since 1999
Chairman since 2002
Chairman of the Board,
Chief Executive Officer
INTRUST Bank
Wichita, Kansas

MOLLIE H. CARTER (42)
Director since 2003
President and Chief
Executive Officer
Sunflower Banks, Inc.
Salina, Kansas
Committees: Compensation, Finance

R.A. EDWARDS III (59)
Director since 2001
President and Chief
Executive Officer
First National Bank
of Hutchinson
Hutchinson, Kansas
Committees: Audit, Nominating and Corporate Governance

JERRY B. FARLEY (58)
Director since 2004
President
Washburn University
Topeka, Kansas
Committees: Audit, Nominating and Corporate Governance

JAMES S. HAINES, JR. (58)
Director since 2002
President and Chief
Executive Officer
Westar Energy, Inc.
Topeka, Kansas

B. ANTHONY ISAAC (51)
Director since 2003
President
LodgeWorks, L.P.
Wichita, Kansas
Committees: Compensation, Finance

ARTHUR B. KRAUSE (63)
Director since 2003
Executive Vice President
and Chief Financial Officer
(Retired)
Sprint Corporation
Naples, Florida
Committees: Audit, Finance

SANDRA A.J. LAWRENCE (47)
Director since 2004
Senior Vice President and
Treasurer
Midwest Research Institute
Kansas City, Missouri
Committees: Compensation, Nominating and Corporate Governance

MICHAEL F. MORRISSEY (62)
Director since 2003
Managing Partner (Retired)
Ernst & Young LLP
Naples, Florida
Committees: Audit, Compensation

JOHN C. NETTELS, JR. (48)
Director since 2000
Partner
Stinson Morrison Hecker LLP
Overland Park, Kansas
Committee: Nominating and Corporate Governance

Ages and years of service are as of December 31, 2004.

OFFICERS

JAMES S. HAINES, JR. (58)
18 years of service
President and Chief
Executive Officer

WILLIAM B. MOORE (52)
24 years of service
Executive Vice President
and Chief Operating Officer

MARK A. RUELLE (43)
12 years of service
Executive Vice President
and Chief Financial Officer

DOUGLAS R. STERBENZ (41)
7 years of service
Senior Vice President,
Generation and Marketing

BRUCE A. AKIN (40)
17 years of service
Vice President, Administrative
Services

GREG A. GREENWOOD (39)
11 years of service
Treasurer

KELLY B. HARRISON (46)
23 years of service
Vice President, Regulatory

DOUGLAS J. HENRY (52)
26 years of service
Vice President, Power Delivery

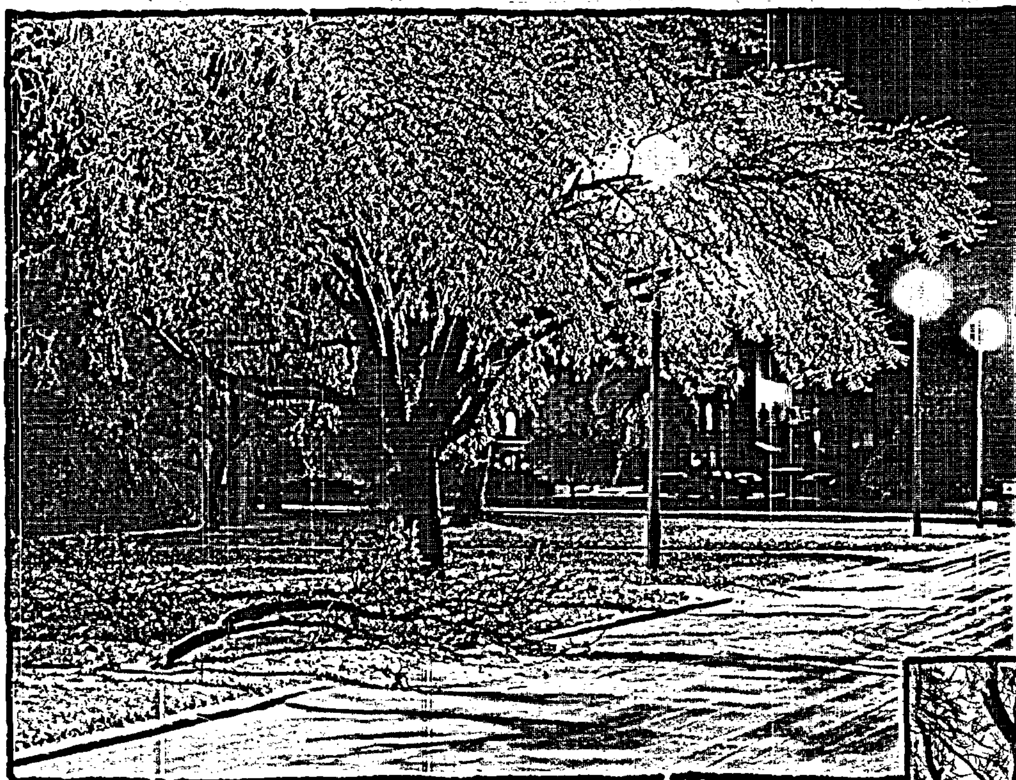
LARRY D. IRICK (48)
5 years of service
Vice President, General Counsel
and Corporate Secretary

PEGGY S. LOYD (47)
26 years of service
Vice President, Corporate
Compliance and Internal Audit

JAMES J. LUDWIG (46)
14 years of service
Vice President, Public Affairs

LEE WAGES (56)
27 years of service
Vice President, Controller

CAROLINE A. WILLIAMS (48)
29 years of service
Vice President, Customer Care



Following the January 2005 ice storm, Westar Energy invited employees to submit photos they took showing the beauty and destruction of the storm and our employees working to restore power. Of the nearly 200 photos submitted, three were chosen for publication.

At left: Jim Wishart, director, work force coordination, took this photo in front of the Westar Energy System Control building on January 5. Below: Brad Kesl, electric distribution supervisor, took this photo of Bernie Braun, agent, as he works to restore power to customers southeast of Marion. Kesl also photographed Salina crews through icy branches as they drove to work on restoration of power to customers near Marion.

Westar Energy braves ice, cold to restore power

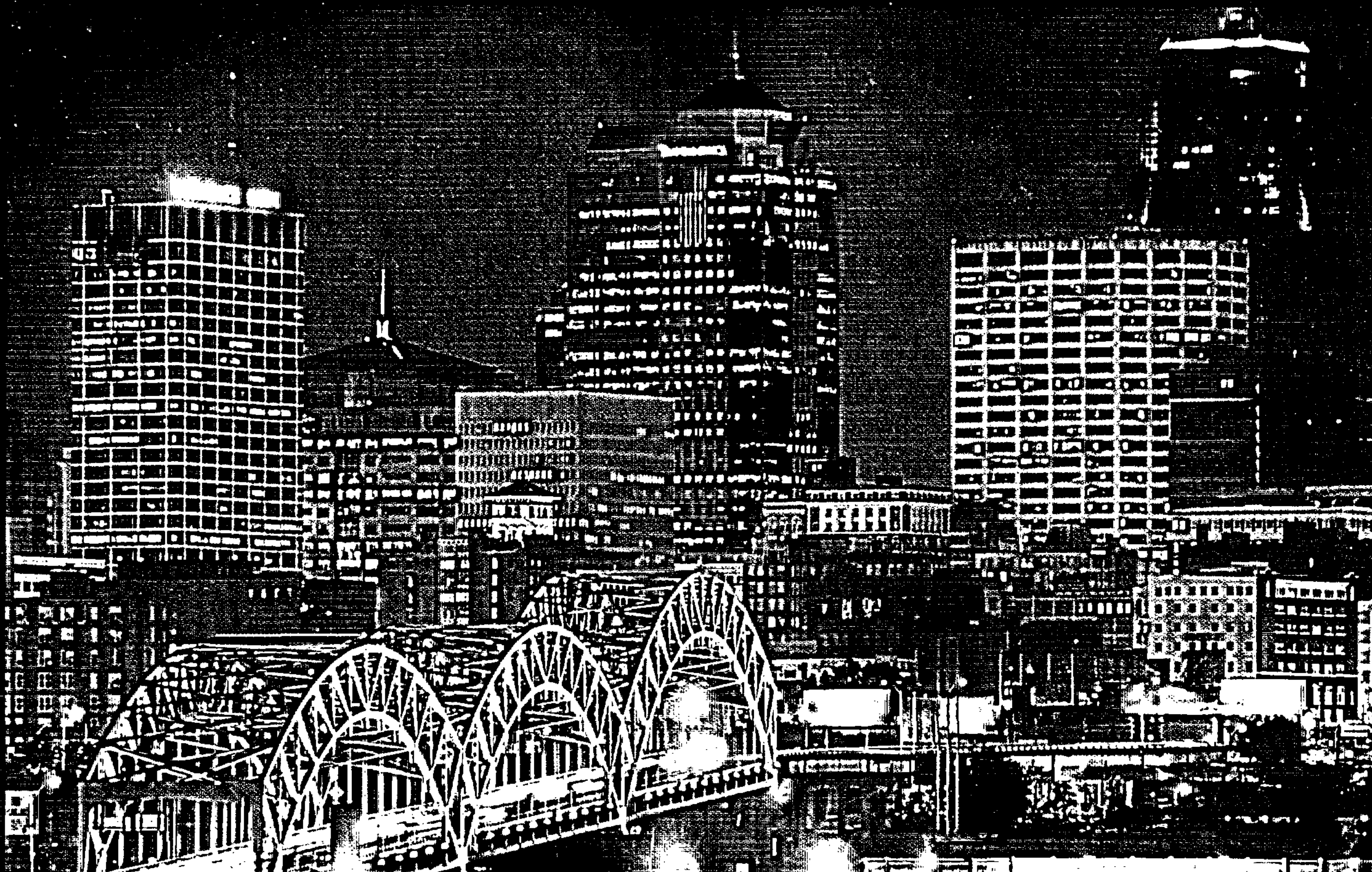
An ice storm covered much of Westar Energy's service territory January 4, knocking out power to more than 260,000 customers. Ice accumulation caused many of them to lose power multiple times. In the hardest hit areas, some customers were without power for 10 days. Westar Energy enlisted the help of utilities and contractors from 17 states to assist with recovery efforts.

Faced with the worst ice storm in the company's history, storm managers divided Wichita and south-central Kansas into work zones. Tree trimming crews cleared branches from power lines enabling restoration. Utility crews gathered at staging areas awaiting assignments as daylight appeared. With work orders and boxed lunches in hand, they canvassed areas going from home to home restoring service until night fell.

Truly tested, Westar Energy employees and customers showed their ability to face adversity and get the job done.

Westar Energy.

P.O. Box 889, Topeka, Kansas 66601-0889
www.wr.com



Lighting the Way

2004 ANNUAL REPORT

GREAT PLAINS ENERGY (NYSE: GXP), headquartered in Kansas City, Missouri, pursues attractive total returns by managing diverse energy-related businesses to achieve stability, disciplined growth and dividends for shareholders. The core holdings of Great Plains Energy are:

GREAT PLAINS℠ ENERGY

KANSAS CITY POWER & LIGHT, headquartered in Kansas City, Mo., is Great Plains Energy's core business. A leading regulated provider of electricity in the Midwest, this integrated utility serves nearly 495,000 customers in 24 counties of western Missouri and eastern Kansas. An experienced management team has developed a firm with strong cash flow, competitive retail electricity rates and a highly reliable delivery system. Operating eight stations with 25 generating units providing power to customers and selling into the wholesale market, KCP&L has more than 4,000 megawatts of efficient generation assets.

STRATEGIC ENERGY is a national competitive electricity supplier serving customers in California, Maryland, Massachusetts, Michigan, New Jersey, New York, Ohio, Pennsylvania and Texas. During 2004, Strategic Energy reported revenue of $1.4 billion and earnings of $0.59 per GXP share. Strategic Energy provides long-term growth potential in a large and growing market.

Lighting the way:

Working together, Great Plains Energy and our communities plan for a bright future.

Public Forums

Collaboration is at the heart of achieving consensus on how best to meet tomorrow's energy needs, as citizens attending public forums on KCP&L construction plans understand.

Strategic Seminars

The best ideas come from bringing together diverse stakeholders – employees, energy users, government officials, activists and ordinary citizens – to work on solving energy challenges.

At Great Plains Energy, collaboration is the starting point for action. To look into the future and create a strategic plan, we reached out in 2004 to customers, community leaders, legislators, employees and shareholders – the people we serve. Together, we generated ideas that are lighting the way for our common future.

Continued on inside back cover >

Selected Financial Data

(dollars in millions except per share amounts)	2004[B]	2003[B]	2002[B]	2001	2000
GREAT PLAINS ENERGY[A]					
Operating revenues	$ 2,464	$ 2,148	$ 1,802	$ 1,399	$ 1,086
Income (loss) from continuing operations[C]	$ 174	$ 190	$ 137	$ (28)	$ 53
Net income (loss)	$ 181	$ 145	$ 126	$ (24)	$ 159
Basic and diluted earnings (loss) per common share from continuing operations	$ 2.39	$ 2.72	$ 2.16	$ (0.49)	$ 0.83
Basic and diluted earnings (loss) per common share	$ 2.49	$ 2.07	$ 1.99	$ (0.42)	$ 2.54
Total assets at year-end	$ 3,799	$ 3,682	$ 3,517	$ 3,464	$ 3,309
Total redeemable preferred stock, mandatorily redeemable securities and long-term debt (including current maturities)	$ 1,296	$ 1,347	$ 1,332	$ 1,342	$ 1,286
Cash dividends per common share	$ 1.66	$ 1.66	$ 1.66	$ 1.66	$ 1.66
CONSOLIDATED KCP&L[A]					
Operating revenues	$ 1,092	$ 1,057	$ 1,013	$ 1,287	$ 1,086
Income from continuing operations[D]	$ 143	$ 126	$ 103	$ 116	$ 53
Net income	$ 143	$ 117	$ 96	$ 120	$ 159
Total assets at year-end	$ 3,337	$ 3,303	$ 3,139	$ 3,146	$ 3,309
Total redeemable preferred stock, mandatorily redeemable securities and long-term debt (including current maturities)	$ 1,126	$ 1,336	$ 1,313	$ 1,311	$ 1,286

(A) *Great Plains Energy's consolidated financial statements include consolidated KCP&L, KLT Inc., GPP, IEC and GPES. KCP&L's consolidated financial statements include its wholly owned subsidiary HSS. In addition, KCP&L's consolidated results of operations include KLT Inc. and GPP for all periods prior to the October 1, 2001, formation of the holding company, Great Plains Energy.*

(B) *See Management's Discussion and Analysis for explanations of 2004, 2003 and 2002 results.*

(C) *This amount is before discontinued operations of $7.3, $(44.8), $(7.5), $4.3 and $75.6 million in 2004 through 2000, respectively. In 2002, this amount is before the $3.0 million cumulative effect of a change in accounting principle. For further information, see Notes to Consolidated Financial Statements. In 2000, this amount is before the $30.1 million cumulative effect of changes in pension accounting.*

(D) *This amount is before discontinued operations of $(8.7), $(4.0), $3.6 and $75.6 million in 2003, 2002, 2001 and 2000, respectively. In 2002, this amount is before the $3.0 million cumulative effect of a change in accounting principle. For further information, see Notes to Consolidated Financial Statements. In 2000, this amount is before the $30.1 million cumulative effect of changes in pension accounting.*

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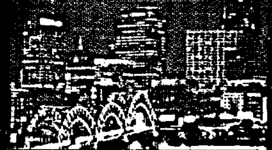
ABOUT THE COVER



Lighting the way into Downtown, the Broadway Bridge gained aesthetic new lighting in 2004 with assistance from Kansas City Power & Light – a very visible community commitment.

(cover image courtesy of Rich Sugg, The Kansas City Star)

2004 marked the launch of our Strategic Intent, a far-reaching guide to the future. This ambitious plan embodies the aspirations of our customers, employees and communities – illuminating a path to reliable, low-cost energy for years to come. Great Plains Energy is demonstrating leadership to make it happen.

"A COMPREHENSIVE STRATEGY FOR THE FUTURE"

Dependable, affordable energy is critical to everyone. So when Great Plains Energy asked our diverse stakeholders to brainstorm about the future, they offered lots of ideas. This collaborative process led to the Strategic Intent shown on pages 3-5. Together, we created a substantive, achievable plan to guide the growth of Great Plains Energy, provide for future energy needs of our customers and deliver sustainable growth in earnings.

GREAT PLAINS ENERGY

Strategic Intent:

Demonstrate Leadership in Supplying and Delivering Electricity and Energy Solutions to Meet the Needs of Our Customers

- This intent is grounded in a solid foundation, thanks to strong operating performance and a competitive asset base, including:
  - A fleet of regulated power plants, including coal plants that are top-tier in total production costs per megawatt hour
  - A delivery system that provides industry-leading reliability and high customer service and satisfaction
  - An industry leader in competitive supply
  - Solid financial performance that includes increased shareholder value and strong dividends over the last three years
- We will position ourselves to benefit from a changing marketplace and technological innovation.
- Our strategy is to build on our core strengths across the company and add capabilities that benefit our customers, employees, investors, partners and the communities we serve.

Read on >

Strategies

Our intent is reflected in a set of strategies that will demonstrate GPE's leadership in the electric industry through disciplined growth:

In the **NEAR TERM,** we plan to extend current capabilities in our regulated and competitive supply businesses by:

- Adding new coal and wind capacity to continue providing customers with reliable and affordable power
- Accelerating environmental upgrades for the existing fleet
- Strengthening our competitive supply business by entering new markets (geographies and segments) and expanding products and services
- Implementing new distributed resources, reliability and energy efficiency programs
- Collaborating and building stronger relationships with customers, regulators and legislators for the overall long-term benefit of us all

Culture

Achieving our strategic intent – making it happen – will require a "winning culture," achieved by:

- Executing extremely well in each business and taking greater advantage of our strengths across the company
  - Delivering operational leadership through competitive cost structures, strong customer service, breadth of regulatory knowledge, world-class safety and practical application of innovative technologies and processes
  - Developing insights about our marketplaces to improve our ability to serve all of our customer segments
  - Creating collaborative partnerships with customers, communities and regulators to achieve mutually beneficial results

Results

Achieving our strategic intent will benefit all our stakeholders by:

- Providing energy solutions that are valued by our customers at prices that are affordable and competitive
- Ensuring greater opportunity for personal development and the reward of mutual accomplishment for our employees in an organization that encourages innovation and operational excellence
- Improving the total living environment and economic vitality of the communities GPE serves
- Building valued long-term alliances with key business partners
- Delivering strong financial performance to our investors

OVER TIME, we will continue to build capabilities in select areas most important to establishing a leadership position by:

- Anticipating fundamental changes in how electricity is supplied, delivered and used in both regulated and competitive businesses including:
  - Continuing to prudently apply new technologies important to our businesses, including technologies to improve coal plant performance, address environmental challenges and increase responsiveness to customer and community demand
  - Developing valued customer solutions that go beyond traditional electric offerings
  - Enhancing our ability to serve customers by strengthening core capabilities and processes inside our company, including performance management, customer relationships and talent development
- Advocating increased efficiency of retail and wholesale markets where there is a significant customer benefit
- Working proactively with organizations in our markets to achieve maximum economic and environmental benefits

- Partnering with customers to create mutually beneficial relationships that strengthen our bonds
  - Using a consultative sales approach to meet customer needs
  - Developing innovative electric service and energy solutions that help our customers maximize their own value and that of their own customers
  - Providing responsive, superior customer service
- Demonstrating environmental responsibility and a commitment to community improvement
  - Making appropriate and timely investments to ensure environmental compliance
  - Partnering with and strategically investing in communities in which we operate to improve quality of life in a meaningful way
- Enhancing our skills
  - Broadening knowledge about all areas of our business – within and across regulated and non-regulated business segments
  - Bolstering sales and marketing capability
  - Clarifying and investing in required leadership skills and behaviors
- Creating an engaged organization guided by strong values, inspired leaders and shared accountability
  - Promoting the GPE IDEAL: Inspired leadership, Disciplined performance management, Engaged employees, Accountability and Loyalty.
  - Developing talented leaders who are inspired, passionate and committed
  - Using a disciplined performance management system to foster shared accountability, collaboration and increased personal growth and contribution

"Now we are building on a shared vision to create the vibrant, innovative energy provider that our customers and other stakeholders need for the future."

– Mike Chesser
Chairman and Chief Executive Officer

Dear Fellow Shareholder

2004 was a landmark year for Great Plains Energy. We delivered on our promise of demonstrating operational excellence, while charting a comprehensive and compelling course for the future.

I'm proud of what we accomplished this year, and proud of how people at all levels of the company worked together and collaborated with our customers and communities.

While our financial performance was strong, I believe that 2004 will be remembered more for our efforts to step back and develop a longer-term strategic intent. Our future success will be based on implementation of this intent, which includes building a cultural environment where our people are inspired, accountable and engaged.

A Year of Strong Operating Performance

Despite challenging conditions, 2004 was a record-setting year in both the utility and competitive supply businesses. Our success was driven by a variety of initiatives to improve operating effectiveness, as well as by our efforts to shape a Winning Culture within the organization.

Bill Downey
President and Chief Operating Officer

Mike Chesser
Chairman and Chief Executive Officer

Kansas City Power & Light

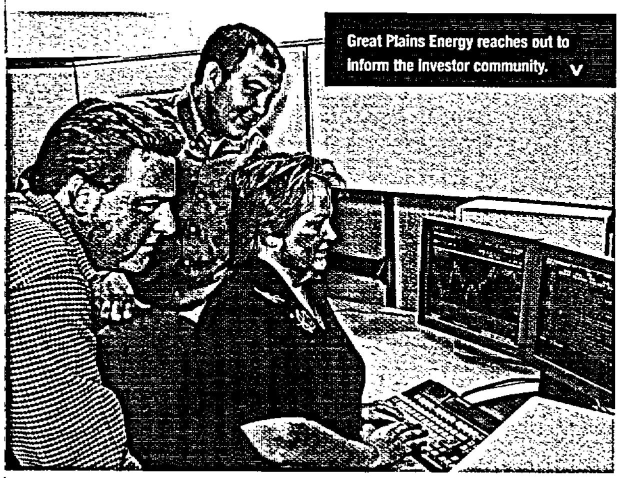
KCP&L delivered outstanding performance in 2004, producing higher earnings and cash flow while providing top-tier service to our customers. This accomplishment is more impressive in light of the challenging weather conditions in our service area in 2004, which included one of the coolest summers on record and a higher-than-normal number of damaging storms.

Our generation fleet achieved a record-breaking year. Performance improvements led to record equivalent availability and capacity factors for the total baseload generation fleet. Our Iatan, LaCygne 1, LaCygne 2 and Montrose Generating Stations set all-time megawatt generation records, thanks to employees' continued focus on operational excellence and proactive maintenance strategies.

"Our eyes are on the future ... and we intend to build value."

With this level of increased output, reduced summer retail demand and higher wholesale market prices, our Power Marketing group was able to produce record wholesale revenues of more than $200 million, up 27% from 2003.

We also provided some of the most reliable service in the nation. In September, KCP&L earned the prestigious Reliability One award for the highest reliability performance in our region. The award committee noted that our excellent record is the result of years of wise decisions and consistent hard work and dedication on the part of our employees in Distribution and Transmission. Read on >



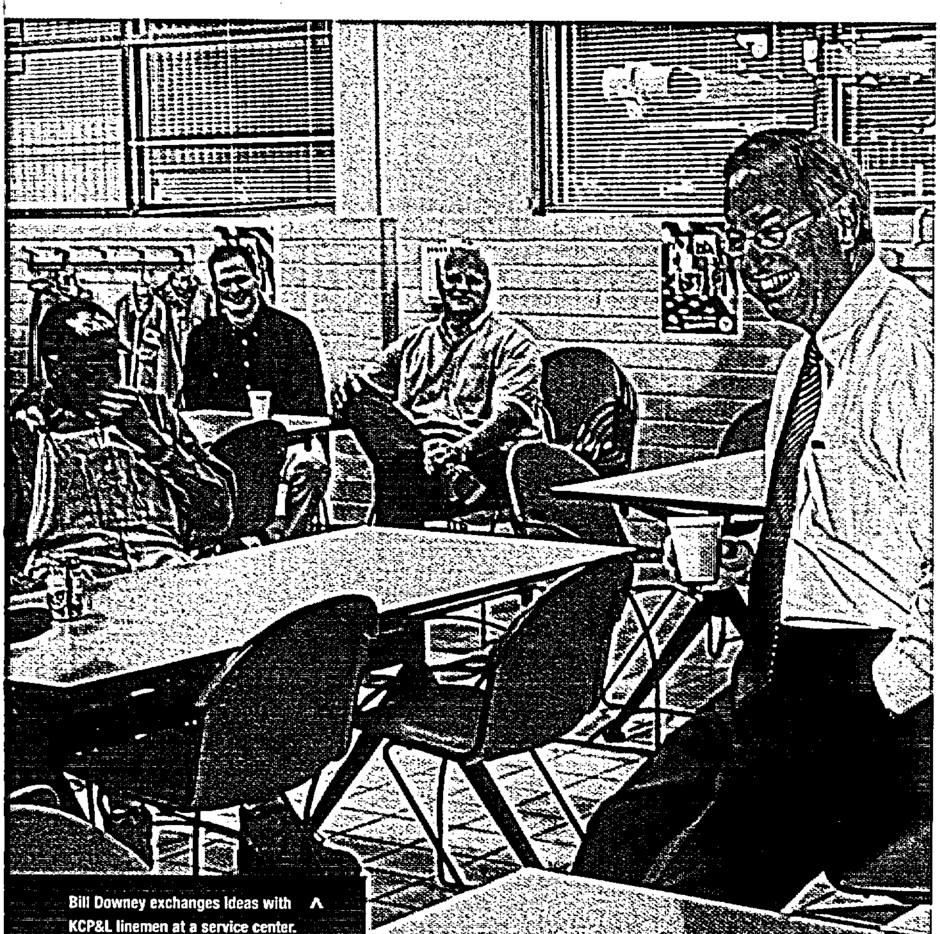
Great Plains Energy reaches out to inform the investor community.

KCP&L's Diversity Council fosters relationships in an inclusive workplace.

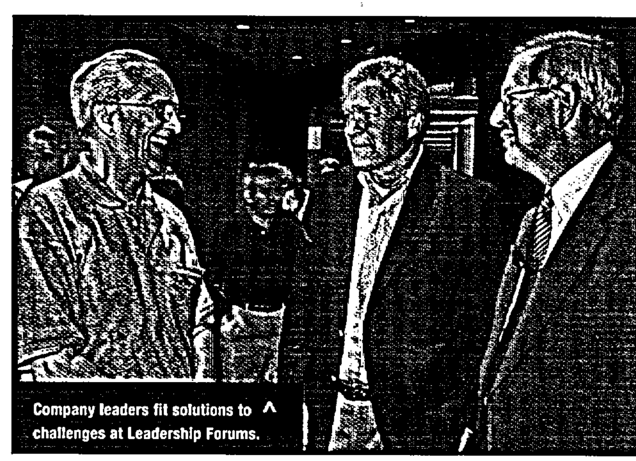
Training enhances first-line supervisor skills which maximizes team performance.

Creating a winning culture: Engaged people, talented leaders commit to executing a shared vision

Great Plains Energy is committed to creating a winning culture – an engaged organization empowered by strong values, inspired leaders and shared accountability. We are charting new kinds of partnerships, forging collaborative ties in our communities, developing our leaders' skills at all levels and encouraging inclusiveness in our workforce.



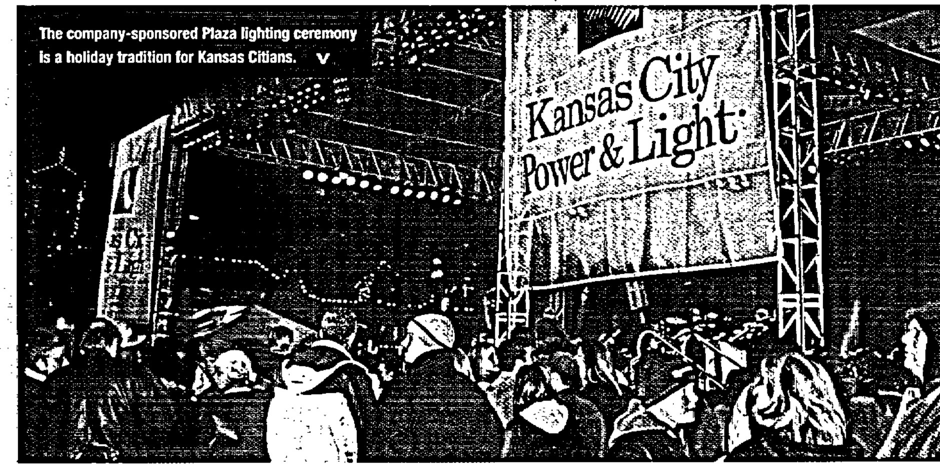
Bill Downey exchanges ideas with KCP&L linemen at a service center.



Company leaders fit solutions to challenges at Leadership Forums.

Great Plains Energy deposits $1 million in minority-owned Douglass Bank.

Employee volunteers join holiday fundraising to help the less fortunate.

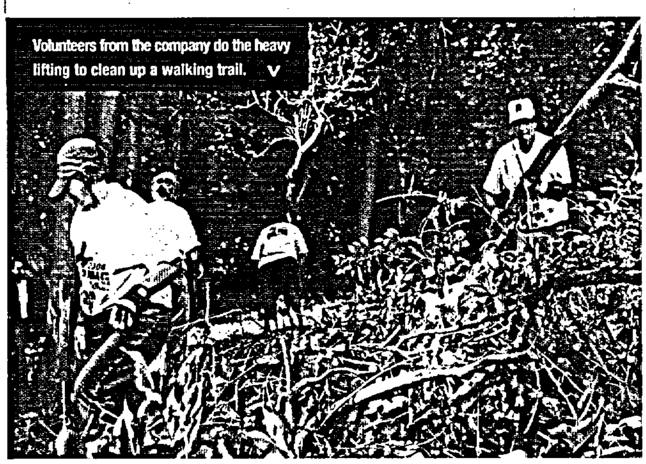


The company-sponsored Plaza lighting ceremony is a holiday tradition for Kansas Citians.

Employees help with Downtown beautification and cleanup.

Community commitment: business as usual in building our future at Great Plains Energy

Getting involved, solving a problem, lending a helping hand: The employees of Great Plains Energy demonstrate great enthusiasm for community commitment. We believe in investing time and money where we do business. We understand that to earn recognition as a leader, our company must be a catalyst for positive change in issues like energy affordability, the environment and human development. Our culture values personal commitment, above and beyond our "day jobs." For us, investing in the community is business as usual.

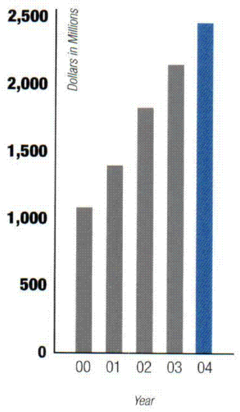


Volunteers from the company do the heavy lifting to clean up a walking trail.

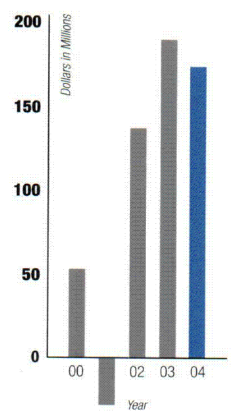
KCP&L has been recognized for our efforts in restoring native grasses and wildflowers.

The KCP&L-sponsored Lorikeets exhibit educated zoo visitors about rainforest conservation.

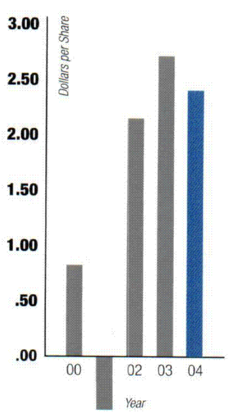
GPE Operating Revenues



GPE Income (Loss) from Continuing Operations



GPE Basic and Diluted Earnings (Loss) per Common Share from Continuing Operations



KCP&L faced an unusually large number of storm-related outages in 2004, but through the efforts of our people and improved processes, we continued to decrease the time it takes to restore power to customers after major storm outages. Our Delivery group continues to innovate – completing more than 100 performance improvement initiatives in 2004 alone. Technological innovations have also improved performance. We launched a program to install automated network protectors, for example, that remotely notify us about malfunctions, saving time and money by helping us detect problems faster with less manpower.

Along with internal initiatives, we also helped form a consortium of mid-sized utilities during 2004 to collaboratively seek additional performance improvement and cost savings opportunities for the industry.

We are proud of our continued improvements in Customer Service. In less than three years, service levels have improved dramatically, while costs have decreased. The top-tier performance delivered to our customers in 2004 earned KCP&L national recognition with the ServiceOne™ award. The award is based on an electric utility's performance in the Call Center, Billing, Meter Reading, Field Service and Credit functions.

Safety is a cornerstone of operational excellence, and I'm pleased to report that our emphasis on moving to world-class safety performance produced solid results in 2004. We established a new Corporate Safety Council during the year to create greater levels of safety awareness by promoting widespread participation and consistently applying best practices to sustain cultural change

"Generating goodwill reinforces our role as a trusted leader in energy delivery."

across all divisions. This emphasis helped lead to our entire Generation Division achieving the lowest total case incident rate in its history and the Delivery Division reducing the severity of incidents by 50%.

Strategic Energy

Strategic Energy, our competitive electricity supply business, continued to grow, and posted strong revenues and earnings in 2004. This was achieved despite market conditions that were very challenging for competitive supply firms in the second half of 2004. Wholesale electricity prices moved steadily higher during most of the year and, in several markets, were higher than the standard offer rates of the host utilities that provide the main alternative to competitive suppliers like Strategic Energy. While host utility rates will adjust to wholesale prices over time, the regulatory lag in the process continues to provide a headwind for competitive supply sales as we enter 2005.

Consistent with our position as one of the leading national electricity retailers, Strategic Energy is responding to these challenges by increasing our focus on satisfying customer needs and revamping key internal business processes. Read on >

KCP&L's Richard Spring (back left) accepts honor for prairie preservation.

Environmental Excellence: Good Stewardship in Action

Great Plains Energy takes care to exercise environmental stewardship: investing in state-of-the-art equipment to improve air and water quality, volunteering for cleanup and beautification, recycling, nurturing wildlife, preserving the land. This commitment builds friendships and alliances. For instance, KCP&L was honored in 2004 by the Kansas City Parks & Recreation Board for restoring prairie habitat on the rolling hills of Jerry Smith Farm Park. As the community prospers, so do we.

C01

For example, Strategic Energy has introduced several contract options to satisfy different customers' desires such as: higher or lower exposure to wholesale commodity risk; a balanced approach to power needs with a combination of short, medium and longer term contracts; and streamlined, less complex products for convenience while ensuring protection from energy price volatility.

At Strategic Energy we are also transforming our internal capabilities and business processes to maintain our leadership in this rapidly changing market. We are adopting best-in-class marketing and sales processes to identify the right customer at the right time with the right product. We are also upgrading our supply and portfolio management capabilities in order to reduce supply costs, which represent more than 90% of Strategic Energy's total costs, while remaining true to the prudent risk management philosophy that has been one of the hallmarks of the company.

In April, Great Plains Energy increased its ownership in Strategic Energy to just under 100%. We also added talent to the executive team by hiring Shahid Malik as our new CEO. Shahid's depth and breadth of experience in the energy industry, combined with his inspirational leadership style, make him the right leader to help drive this fast-evolving, entrepreneurial business forward.

Great Plains Energy

In addition to the results within our major businesses, we also improved the focus of the portfolio at Great Plains Energy.

We sold two companies that were not strongly aligned with our core businesses, enabling greater management focus. Early in the year, we made the decision to exit our gas exploration and production business, KLT Gas. Through careful management of the sales process over the course of the year, we achieved favorable results from the sale of the KLT Gas properties. In December we entered into a letter of intent to sell Worry Free Services, Inc., a small business that provided residential services in several metropolitan areas and closed the sale in February 2005.

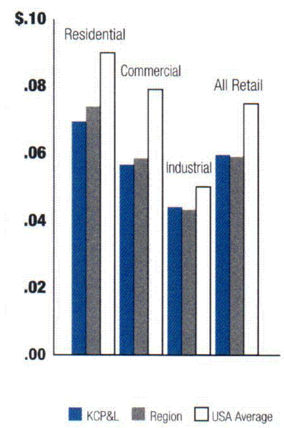
The heart of KCP&L, our efficient fleet of generating stations, performed well in 2004 – delivering reliable, low-cost electricity for customers and returns for shareholders.

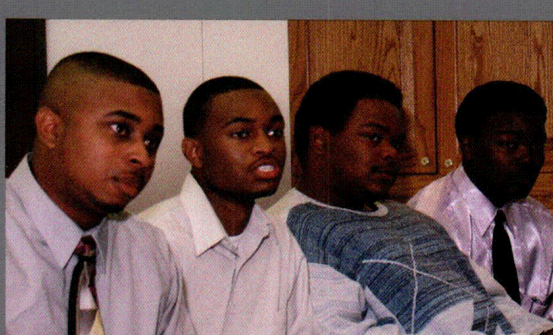
In June, we completed successful $150 million common stock and $163 million equity-linked securities offerings. This improved our capital structure and was well received by investors.

Throughout the year, teams across the Company evaluated and assessed our internal controls over financial reporting required by the Sarbanes-Oxley Act. Management concluded, and our external auditors agreed, that our internal controls over financial reporting are effective as of December 31, 2004. Read on >

KCP&L Average Retail Price Comparison

Cents per KWh
Source: EEI Typical Bills for 12 months ending 6/30/04





Creative problem-solvers (from left): Elree Canty, Aaron Gatlin, James Smith and Terrance Logan, 2004 Full Employment Council interns.

Four Summer Interns Save KCP&L $50,000

A team of summer interns in 2004 became a living example of "winning culture." The four students, ages 19 to 22, were asked by KCP&L to troubleshoot an underground drainage system at Hawthorn Generating Station where too much silt was gathering, requiring expensive cleanouts. In just one week, the team developed a proposed solution of valves and fittings to keep the pipes clear, which KCP&L adopted for cost savings estimated at $50,000 over five years.

C02


Hawthorn plant employees engage generation leader Steve Easley.

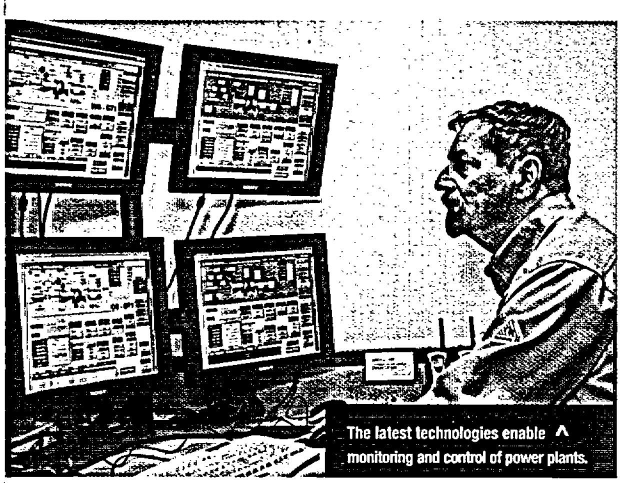

At the wheel, a KCP&L lineman chats with distribution leader Bill Herdegen.

KCP&L delivers reliable, low-cost power – and builds new partnerships with customers.


KCP&L partners with North Kansas City Hospital to maximize energy efficiency.

Customer focus drives excellence

In a dramatically changing energy market, leadership comes from empowering our organization to serve customers in innovative ways. So we are building new skills in our workforce, trying new ways of tracking and improving performance, and reaching into the future to offer new energy solutions for the market. Operational excellence takes shape behind the scenes, when two co-workers converse or a team comes together to tackle a challenge. But our efforts pay off when energy makes a difference in a customer's life.

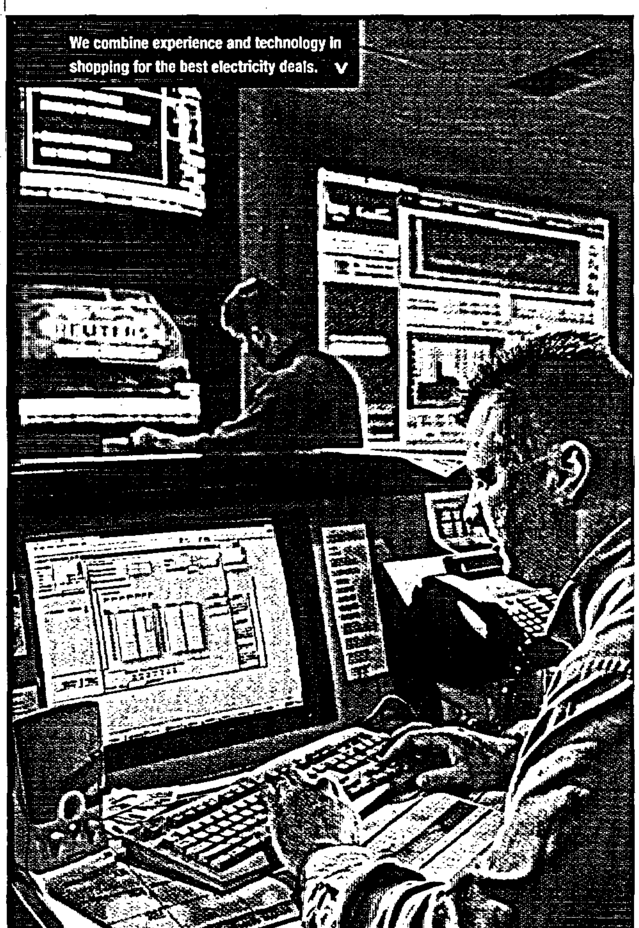

The latest technologies enable monitoring and control of power plants.


KCP&L crews return home after helping Florida utilities restore power after hurricanes.

A team-oriented culture guides Strategic Energy's performance.

Strategic Energy is delivering smart solutions for the challenges of a competitive world.

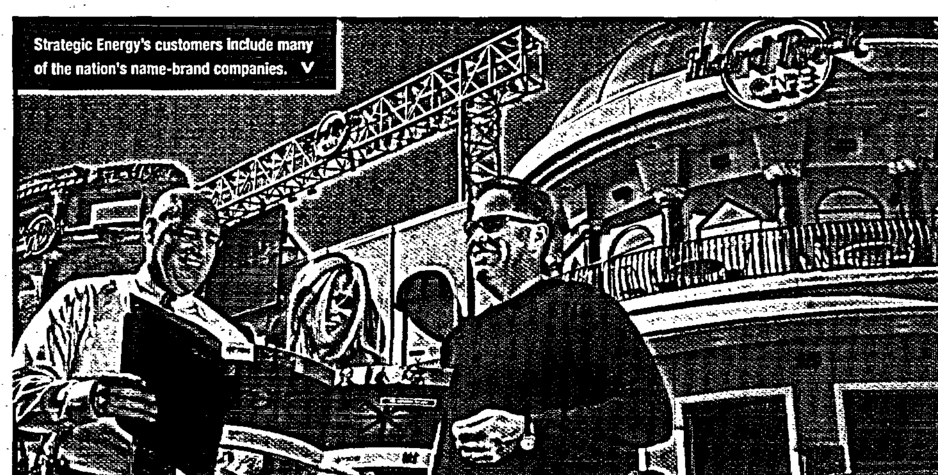
Our Energy Management Center focuses on customers' power needs ... "24/7/365."



We combine experience and technology in shopping for the best electricity deals.

Our value proposition saves money for energy customers with a choice

Strategic Energy provides energy management services in competitive markets nationwide. Nearly 8,500 commercial, institutional and industrial customers nationwide get a reliable supply of electricity at predictable costs from Strategic Energy. Our skilled team can assess a customer's needs, buy energy to match those requirements and provide competitive prices. We sort out a confusing marketplace and offer solutions tailored to the customer. Our value proposition makes sense – we deliver sustainable savings to customers with a choice.



Strategic Energy's customers include many of the nation's name-brand companies.

Building the Foundation for the Future

In January of 2004 we launched a comprehensive strategic planning process. Our approach to strategy development set the tone for how we will do business in the future.

- We engaged employees at all levels of the company, including our bargaining units, to ensure a common understanding and level of awareness.
- We reached out to our customers, community leaders and regulators. This unprecedented level of collaboration enabled us to better understand their perspectives, and they developed a better understanding of the issues facing our company.
- We took an outside-in viewpoint, recruiting industry experts to bring leading thinking from a variety of perspectives, often representing opposing views on key topics.
- We considered multiple aspects of strategy development with an explicit focus on the cultural aspects necessary for success.
- We developed and evaluated alternative scenarios to ensure that while we have a clear strategy, we will stay flexible enough to respond to potential changes in our markets.

This process succeeded on many fronts. It engaged our employees and constituents, increased our mutual understanding of the key issues and resulted in a Strategic Intent that will guide our actions well into the future.

Our Strategic Intent is the roadmap for our company to become an industry leader at supplying and delivering electricity and innovative energy solutions to our customers. It's truly a milestone in the Company's history. *Please refer to pages 4 and 5 for more detail about our Strategic Intent.*

We Have Already Started to Implement Our Strategic Intent

An important priority in our plan is a Winning Culture. By building a place where people can grow and thrive, we're building a company that will also thrive – and produce the kind of results that make shareholders eager to invest. Our business will succeed based on the talent and engagement of our workforce. For us, Winning Culture has a very specific definition – one developed by employees for employees.

> "Our team is well-positioned to thrive in a market that has tremendous untapped potential."

We selected a diverse team to lead the development of a Winning Culture, one in which employee development, growth and empowerment are encouraged and supported. Our employee team captured the spirit of Winning Culture through the concept of the GPE IDEAL. Each letter in the word "I-D-E-A-L" represents a desirable quality in a Winning Culture environment – Inspired leadership, Disciplined performance management, Engaged employees, Accountability and Loyalty.

And as part of this IDEAL, we are finalizing a formal, disciplined performance management process that features balanced scorecards, initiatives, timetables and accountabilities, as well as broad-based employee rewards and recognition. Read on >

New leader will guide Strategic Energy to next level

New CEO Shahid Malik is steering Strategic Energy

Shahid Malik, an energy executive with 20-plus years of experience, joined Strategic Energy as President and CEO on November 10, 2004.

"Strategic Energy is a passionate, talented team of people committed to tackling 21st Century challenges. I'm thrilled by the opportunity to take this company to the next level of customer-led solutions for energy management," Shahid said.

Shahid came to Strategic Energy from Houston-based Sirius Solutions, where he was a senior partner responsible for strategy consulting, leadership and risk management. He also served as Director of Energy Programs and Adjunct Professor at Rice University's Graduate School of Management.

Previous executive positions included diverse responsibilities at Reliant Energy Wholesale Group, Entergy Corporation, Ferrell North America and British Petroleum PLC. He has been active in business segments such as deregulated wholesale and retail marketing activities, as well as risk management, trading and asset management.

Shahid earned a bachelor's degree in Economics from the University of Manchester, England, and an MBA from Rice University.

"In the long run, our greatest competitive advantage will come from a winning culture at Great Plains Energy."

KCP&L's Comprehensive Energy Plan

Another area where the Strategic Intent has already produced results is KCP&L's comprehensive energy plan. This plan was developed to meet the long-term energy needs of the communities we serve – in a way that balances the perspectives of our multiple constituents and is consistent with our Strategic Intent. The key elements of the plan are:

- Majority ownership of a regulated 800-900 MW coal-fired plant
- Environmental investments of approximately $300 million
- Up to 200 megawatts of wind generation
- Demand, efficiency and affordability response programs, including distributed generation to help customers use energy more effectively
- Infrastructure improvements to maintain and improve reliability

A key driver for this investment is the growth within our service territory and the demand for electricity, which we estimate will continue to expand at approximately 2% – 2.5% per year. A prime example of this growth is downtown Kansas City, which is beginning a major revitalization. KCP&L is an integral part of this effort. As I look out my office window, I can see our employees replacing an aging underground electricity infrastructure to deliver power to projects such as H&R Block's new world headquarters and the proposed Sprint Arena. It is estimated that the downtown revival, when completed, will require an additional 20 to 30 megawatts of electricity.

In an effort to make the development of KCP&L's comprehensive plan as open, collaborative and transparent as possible, we met with more than 80 civic and community groups and hosted six public forums in many parts of our service area. We also participated in a series of regulatory workshops in Kansas and Missouri open to all interested parties. We also invited the public to provide comments on the proposal through informational mailings and advertisements. At every stage of the process, we've welcomed input.

Our lengthy and personal grassroots effort helped us incorporate suggestions from all sides of the various issues. This created an even stronger and more viable proposal. The resulting comprehensive plan represents a proactive and sensible approach to meeting the energy, economic and environmental needs of our community throughout the next decade.

We are currently in discussions with participants in both Missouri and Kansas to develop a regulatory structure to make these investments possible. We are working toward an agreement to be submitted to the state commissions that enables us to balance the needs of shareholders, customers, regulators and our community to meet the growing demand for electricity in our region.

Summary

The course we have set for the next decade will address the needs of our customers, community and employees, and will reward shareholders with excellent long-term earnings potential. We have clear direction and a clear commitment to building a Winning Culture. I believe that all of our constituents will look back proudly on 2004 as a year in which we not only demonstrated the power of our businesses to deliver outstanding results, but also established a strong foundation for our longer-term success.

Michael J. Chesser
Chairman and Chief Executive Officer
March 7, 2005

Directors and Officers

AS OF DECEMBER 31, 2004

BOARD OF DIRECTORS

GREAT PLAINS ENERGY

Michael J. Chesser
Chairman of the Board and Chief Executive Officer

Dr. David L. Bodde
Senior Fellow and Professor, Arthur M. Spiro Center for Entrepreneurial Leadership at Clemson University

William H. Downey
President and Chief Operating Officer

Mark A. Ernst
Chairman, President and Chief Executive Officer, H&R Block, Inc.
a global provider of tax preparation, investment, mortgage and accounting services

Randall C. Ferguson, Jr.
Senior Partner for Business Development, Tshibanda & Associates, LLC
a consulting and project management services firm committed to assisting clients to improve operations and achieve long-lasting, measurable results

Dr. William K. Hall
Chairman of Procyon Technologies, Inc.
a holding company with investments in the aerospace and defense industries

Luis A. Jimenez
Senior Vice President and Chief Strategy Officer of Pitney Bowes Inc.
a global provider of integrated mail and document management solutions

James A. Mitchell
Executive Fellow-Leadership, Center for Ethical Business Cultures
a not-for-profit organization assisting business leaders in creating ethical and profitable cultures

William C. Nelson
Chairman, George K. Baum Asset Management
a provider of investment management services to individuals, foundations and institutions

Dr. Linda Hood Talbott
President, Talbott & Associates
consultants in strategic planning, philanthropic management and development to foundations, corporations and non-profit organizations

Robert H. West
Retired Chairman of the Board, Butler Manufacturing Company
a supplier of non-residential building systems, specialty components and construction services

OFFICERS

GREAT PLAINS ENERGY

Michael J. Chesser
Chairman of the Board and Chief Executive Officer

William H. Downey
President and Chief Operating Officer

Andrea F. Bielsker
Senior Vice President – Finance, Chief Financial Officer and Treasurer

Jeanie S. Latz
Executive Vice President – Corporate and Shared Services and Secretary

Brenda Nolte
Vice President – Public Affairs

William G. Riggins
General Counsel

Lori A. Wright
Controller

KANSAS CITY POWER & LIGHT COMPANY

Michael J. Chesser
Chairman of the Board

William H. Downey
President and Chief Executive Officer

Andrea F. Bielsker
Senior Vice President – Finance, Chief Financial Officer and Treasurer

Stephen T. Easley
Vice President – Generation Services

William P. Herdegen III
Vice President – Distribution Operations

Nancy J. Moore
Vice President – Customer Services

Richard A. Spring
Vice President – Transmission Services

Jeanie S. Latz
Secretary

Lori A. Wright
Controller

STRATEGIC ENERGY

Shahid Malik
President and Chief Executive Officer

Shareholder Information

GREAT PLAINS ENERGY FORM 10-K

Great Plains Energy's 2004 annual report filed with the Securities and Exchange Commission on Form 10-K can be found at: *www.greatplainsenergy.com* and is available at no charge upon written request to:

Corporate Secretary
Great Plains Energy Incorporated
P.O. Box 418679
Kansas City, MO 64141-9679

MARKET INFORMATION

Great Plains Energy common stock is traded on the New York Stock Exchange under the ticker symbol GXP. Shareholders of record as of December 31, 2004: 15,188

INTERNET SITE

The company has a site on the Internet at *www.greatplainsenergy.com*. Information available includes company news releases, stock quotes, customer account information, community and environmental efforts, and information of general interest to investors and customers.

Also located on our Web site are the company's Code of Ethics, Corporate Governance Guidelines and the charters for the Audit Committee, Governance Committee, and Compensation and Development Committee of the Board of Directors, which are also available at no charge upon written request to the Corporate Secretary.

COMMON STOCK DIVIDENDS PAID

QUARTER	2004	2003
First	$0.415	$0.415
Second	$0.415	$0.415
Third	$0.415	$0.415
Fourth	$0.415	$0.415

CUMULATIVE PREFERRED STOCK DIVIDENDS

Quarterly dividends on preferred stock were declared in each quarter of 2004 and 2003 as follows:

SERIES	AMOUNT
3.80%	$0.95
4.20%	1.05
4.35%	1.0875
4.50%	1.125

TWO-YEAR COMMON STOCK HISTORY

Great Plains Energy's common stock price range was:

	2004		2003	
QUARTER	HIGH	LOW	HIGH	LOW
First	$35.29	$31.66	$25.00	$21.36
Second	34.36	29.23	30.31	23.75
Third	31.71	28.62	30.84	27.32
Fourth	30.71	28.17	32.78	30.10

ANNUAL MEETING OF SHAREHOLDERS

Great Plains Energy's annual meeting of shareholders will be held at 10:00 a.m. on May 3, 2005, at The Discovery Center, 4750 Troost in Kansas City, Missouri.

DIVIDEND REINVESTMENT AND DIRECT STOCK PURCHASE PLAN

Great Plains Energy offers the opportunity to purchase common shares directly from the Company with an initial minimum investment of $500 through our *Dividend Reinvestment and Direct Stock Purchase Plan*. The Plan offers shareholders several choices, including reinvestment of all or some of their common stock dividends and the option of investing additional cash monthly. Shareholders may choose to deposit their certificates with the transfer agent for safekeeping in their Plan account. For more information or an enrollment form, contact Investor Relations or UMB Bank, n.a. or visit Great Plains Energy's Web site at *www.greatplainsenergy.com*

DIRECT DEPOSIT OF DIVIDENDS AND AUTOMATIC MONTHLY INVESTMENT

Shareholders may elect the convenience of having dividends deposited directly to their checking, savings or other accounts. Shareholders can also choose to authorize automatic monthly deductions from checking or savings accounts to purchase additional shares. *Electing direct deposit or automatic deduction* changes only the manner of dividend payment. Annual report and proxy materials, year-end tax information and other correspondence will be mailed to the shareholder's address of record. For more information, please contact Investor Relations or UMB Bank, n.a., or visit Great Plains Energy's Web site at *www.greatplainsenergy.com*

REGISTERED SHAREHOLDER INQUIRIES

For account information or assistance, including change of address, stock transfers, dividend payments, duplicate accounts or to report a lost certificate, please contact Investor Relations at 800-245-5275.

FINANCIAL COMMUNITY INQUIRIES

Securities analysts and investment professionals seeking information about Great Plains Energy may contact Investor Relations at 816-556-2312.

TRANSFER AGENT AND STOCK REGISTRAR

UMB Bank, n.a.
Securities Transfer Division
P.O. Box 410064
Kansas City, Missouri 64141-0064
800-884-4225 *(toll free)*

CORPORATE GOVERNANCE LISTING STANDARDS CERTIFICATION

On May 18, 2004, the company submitted its Annual CEO Certification to the New York Stock Exchange (NYSE). Mr. Chesser, Chairman of the Board and Chief Executive Officer of the company, certified that as of May 17, 2004, he was not aware of any violation by the company of NYSE Corporate Governance listing standards.

Financial Report

CAUTIONARY STATEMENTS REGARDING CERTAIN FORWARD-LOOKING INFORMATION

Statements made in this report that are not based on historical facts are forward-looking, may involve risks and uncertainties, and are intended to be as of the date when made. In connection with the safe harbor provisions of the Private Securities Litigation Reform Act of 1995, the registrants are providing a number of important factors that could cause actual results to differ materially from the provided forward-looking information. These important factors include:

- *future economic conditions in the regional, national and international markets, including but not limited to regional and national wholesale electricity markets*
- *market perception of the energy industry and the Company*
- *changes in business strategy, operations or development plans*
- *effects of current or proposed state and federal legislative and regulatory actions or developments, including, but not limited to, deregulation, re-regulation and restructuring of the electric utility industry and constraints placed on the Company's actions by the Public Utility Holding Company Act of 1935*
- *adverse changes in applicable laws, regulations, rules, principles or practices governing tax, accounting and environmental matters including, but not limited to, air quality*
- *financial market conditions and performance including, but not limited to, changes in interest rates and in availability and cost of capital and the effects on the Company's pension plan assets and costs*
- *credit ratings*
- *inflation rates*
- *effectiveness of risk management policies and procedures and the ability of counterparties to satisfy their contractual commitments*
- *impact of terrorist acts*
- *increased competition including, but not limited to, retail choice in the electric utility industry and the entry of new competitors*
- *ability to carry out marketing and sales plans*
- *weather conditions including weather-related damage*
- *cost, availability and deliverability of fuel*
- *ability to achieve generation planning goals and the occurrence of unplanned generation outages*
- *delays in the anticipated in-service dates of additional generating capacity*
- *nuclear operations*
- *ability to enter new markets successfully and capitalize on growth opportunities in non-regulated businesses*
- *performance of projects undertaken by the Company's non-regulated businesses and the success of efforts to invest in and develop new opportunities, and*
- *other risks and uncertainties.*

This list of factors is not all-inclusive because it is not possible to predict all factors.

GLOSSARY OF TERMS

The following is a glossary of frequently used abbreviations or acronyms that are found throughout this report.

Abbreviation or Acronym	Definition
35 Act	Public Utility Holding Company Act of 1935, as amended
ARO	Asset Retirement Obligations
CAIR	Clean Air Interstate Rule
Clean Air Act	Clean Air Act Amendments of 1990
CO_2	Carbon Dioxide
Compact	Central Interstate Low-Level Radioactive Waste Compact
Company	Great Plains Energy Incorporated and its subsidiaries
Consolidated KCP&L	KCP&L and its subsidiary, HSS
COSO	Committee of Sponsoring Organizations
Digital Teleport	Digital Teleport, Inc.
DOE	Department of Energy
DTI	DTI Holdings, Inc. and its subsidiaries, Digital Teleport, Inc. and Digital Teleport of Virginia, Inc.
EBITDA	Earnings before interest, income taxes, depreciation and amortization
EEI	Edison Electric Institute
EIRR	Environmental Improvement Revenue Refunding
EPA	Environmental Protection Agency
EPS	Earnings per common share
ERISA	Employee Retirement Income Security Act of 1974
FASB	Financial Accounting Standards Board
FELINE PRIDES^{SM}	Flexible Equity Linked Preferred Increased Dividend Equity Securities, a service mark of Merrill Lynch & Co., Inc.
FERC	Federal Energy Regulatory Commission
FIN	Financial Accounting Standards Board Interpretation
GAAP	Generally Accepted Accounting Principles
GPP	Great Plains Power Incorporated, a wholly owned subsidiary of Great Plains Energy
Great Plains Energy	Great Plains Energy Incorporated and its subsidiaries
Holdings	DTI Holdings, Inc.
HSS	Home Service Solutions Inc., a wholly owned subsidiary of KCP&L
IEC	Innovative Energy Consultants Inc., a wholly owned subsidiary of Great Plains Energy
IRS	Internal Revenue Service
ISO	Independent System Operator
KCC	The State Corporation Commission of the State of Kansas
KCP&L	Kansas City Power & Light Company, a wholly owned subsidiary of Great Plains Energy
KLT Energy Services	KLT Energy Services Inc., a wholly owned subsidiary of KLT Inc.
KLT Gas	KLT Gas Inc., a wholly owned subsidiary of KLT Inc.
KLT Gas portfolio	KLT Gas natural gas properties
KLT Inc.	KLT Inc., a wholly owned subsidiary of Great Plains Energy
KLT Investments	KLT Investments Inc., a wholly owned subsidiary of KLT Inc.
KLT Telecom	KLT Telecom Inc., a wholly owned subsidiary of KLT Inc.
KW	Kilowatt

Abbreviation or Acronym	Definition
kWh	Kilowatt hour
Lease Trust	Lessor for KCP&L's synthetic lease arrangement for five combustion turbines
MAC	Material Adverse Change
MACT	Maximum Achievable Control Technology
MODOR	Missouri Department of Revenue
MPSC	Missouri Public Service Commission
MW	Megawatt
MWh	Megawatt hour
NEIL	Nuclear Electric Insurance Limited
NO_x	Nitrogen Oxide
NPNS	Normal purchases and normal sales exception under SFAS No. 133, as amended
NRC	Nuclear Regulatory Commission
OCI	Other Comprehensive Income
Receivables Company	Kansas City Power & Light Receivables Company, a wholly owned subsidiary of KCP&L
RSAE	R.S. Andrews Enterprises, Inc., a subsidiary of HSS
RTO	Regional Transmission Organization
SEC	Securities and Exchange Commission
SE Holdings	SE Holdings, L.L.C.
Services	Great Plains Energy Services Incorporated
SFAS	Statement of Financial Accounting Standards
SO_2	Sulfur Dioxide
SO_X	Sulfur Oxide
SPP	Southwest Power Pool, Inc.
Strategic Energy	Strategic Energy, L.L.C., a subsidiary of KLT Energy Services
WCNOC	Wolf Creek Nuclear Operating Corporation
Wolf Creek	Wolf Creek Generating Station
Worry Free	Worry Free Service, Inc., a wholly owned subsidiary of HSS

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The Management's Discussion and Analysis of Financial Condition and Results of Operations that follow are a combined presentation for Great Plains Energy and consolidated KCP&L, both registrants under this filing. The discussion and analysis by management focuses on those factors that had a material effect on the financial condition and results of operations of the registrants during the periods presented. It should be read in conjunction with the accompanying consolidated financial statements and related notes.

SIGNIFICANT EVENTS IN 2004

- Exited the KLT Gas business
- Developed a comprehensive strategic intent
- Initiated discussions with interested participants on a comprehensive energy plan at KCP&L
- Completed an equity offering to strengthen the balance sheet
- Purchased an additional indirect interest in Strategic Energy

OVERVIEW

Great Plains Energy is a public utility holding company registered with and subject to the regulation of the SEC under the 35 Act. Great Plains Energy does not own or operate any significant assets other than the stock of its subsidiaries. Great Plains Energy's direct subsidiaries are KCP&L, KLT Inc., GPP, IEC and Services. As a diversified energy company, Great Plains Energy's reportable business segments include KCP&L and Strategic Energy.

KCP&L

KCP&L is an integrated, regulated electric utility that engages in the generation, transmission, distribution and sale of electricity. KCP&L has over 4,000 MWs of generating capacity and has transmission and distribution facilities that provide reliable affordable electricity to almost 495,000 customers in the states of Missouri and Kansas. KCP&L has continued to experience modest load growth annually through increased customer usage and additional customers. Rates charged for electricity are below the national average.

KCP&L has a wholly owned subsidiary, HSS, which held a residential services investment, Worry Free. HSS entered into a letter of intent to sell Worry Free in December 2004 and closed the sale in February 2005.

Strategic Energy

Strategic Energy provides competitive electricity supply services by entering into contracts with its customers to supply electricity. Strategic Energy does not own any generation, transmission or distribution facilities. Of the states that offer retail choice, Strategic Energy operates in California, Maryland, Massachusetts, Michigan, New Jersey, New York, Ohio, Pennsylvania and Texas. Strategic Energy also provides strategic planning and consulting services in the natural gas and electricity markets.

Great Plains Energy owns just under 100% of the indirect interest in Strategic Energy after IEC's May 2004 purchase of an additional 11.45% indirect interest. See Note 8 to the consolidated financial statements for additional information about the acquisition.

Strategic Energy serves approximately 8,500 customers including numerous Fortune 500 companies, smaller companies and governmental entities. Strategic Energy provides competitive electricity supply to over 54,000 commercial, institutional and small manufacturing accounts. Strategic Energy had a

79% customer retention rate for 2004 and expects continued growth in 2005, with MWhs delivered projected to range from 21 to 23 million. The increase in MWhs delivered is expected to be more than offset by a decline in average gross margin per MWh. Strategic Energy currently expects the gross margin per MWh on new customer contracts to average from $3.00 to $4.00 and gross margin per MWh on total customer contracts to average $4.60 to $5.00 in 2005.

Based solely on expected usage under current signed contracts, Strategic Energy has forecasted future MWh commitments (backlog) of 15.4 million, 4.4 million and 1.2 million for the years 2005 through 2007, respectively. Strategic Energy expects to deliver additional MWhs in these years through growth in existing markets, retention of existing customers and expansion into new markets. Higher wholesale energy prices have reduced savings available to customers in some markets compared to prevailing utility rates, which have created more customer price sensitivity and reduced average contract lengths and the rate of backlog growth.

STRATEGIC INTENT

Over the first six months of 2004, the Company engaged in a comprehensive strategic planning process to map its view of the future of the electric industry, and ultimately the Company, over the next five to ten years. This inclusive process drew on the creativity and skills of employees, outside experts and community leaders. The strategic planning process sought to enhance the disciplined growth of the Company and build upon the strong foundation of KCP&L and Strategic Energy. This platform for growth provides a balanced mix of regulated earnings from the utility operations of KCP&L and the potential continued growth of Strategic Energy as it expands its presence in competitive retail markets.

KCP&L held a series of public forums during June and July 2004 in Missouri and Kansas to discuss how to meet the area's growing need for electricity and cleaner air. In July 2004, Great Plains Energy unveiled six key elements to its long-range strategic intent.

- KCP&L will expand and diversify its regulated supply portfolio to include new coal and wind generation.
- KCP&L will accelerate its investments in improving the environmental performance of its fleet, helping to protect its community's quality of life and preparing for an uncertain future of potentially more stringent regulations.
- KCP&L will adopt new delivery technology to enhance the reliability and efficiency of its delivery system. This technology will allow KCP&L to transform the delivery grid from a one-way to a two-way system. Customers will serve as both consumers and virtual suppliers of electricity through distributed generation and various demand response programs.
- Great Plains Energy, through Strategic Energy, will continue to profitably grow its competitive supply business, expanding into new markets, and creating new offerings when economical, and further cementing its reputation as the premium energy retailer from the standpoint of customer focus and value added.
- Great Plains Energy will collaborate even more closely with customers, communities and regulators to take a broader view in anticipating and meeting their energy needs.
- Great Plains Energy will continue to manage its business to achieve disciplined growth, and strong operating performance and deliver strong returns to its shareholders.

Since the July 2004 announcement, Strategic Energy has initiated several product innovations and process improvements to adapt to market conditions and changing customer needs. Strategic Energy has developed new product offerings including contract options to satisfy the desire of some customers to accept more commodity risk themselves in the near term, contracts that trigger automatically if prices fall to predefined levels and contracts to aid customers who desire to take a balanced approach to their power needs with a combination of short, medium and longer term contracts. Strategic Energy is also implementing processes to sharpen its customer targeting approach to insure that the right products and services are being offered to various customer segments to meet customers' needs. Additionally, electricity supply costs represent over 90% of Strategic Energy's total costs. Strategic Energy is currently exploring innovative ways to manage these supply costs to enhance its competitiveness.

Since the July 2004 announcement, KCP&L, through a MPSC established workshop docket, began discussions with interested participants, including the MPSC staff and the KCC staff, among others, to collaborate on and develop a regulatory plan to implement KCP&L's proposed comprehensive energy plan, which includes:

- accelerated environmental investments of $300 million to $350 million for selected existing plants,
- investment in up to 200 megawatts of wind generation,
- building and owning up to 500 megawatts of an 800 to 900 megawatt coal fired plant at the Iatan site in Missouri and
- development of technologies and pilot programs to help customers conserve energy.

The proposal has the potential to add approximately $1.1 billion in capital investment for KCP&L over the next five years and is dependent upon approvals from the MPSC and KCC. In February 2005, the MPSC issued an order closing a workshop docket established specifically for the discussions. KCP&L continues in discussions with the interested participants with the goal of developing an agreement on implementation of the comprehensive energy plan to be formally submitted by KCP&L to the MPSC and KCC for approval. KCP&L anticipates that the next step in the process would include hearings scheduled by the MPSC and KCC to take testimony regarding the implementation of the comprehensive energy plan.

RELATED PARTY TRANSACTIONS

See Note 12 to the consolidated financial statements for information regarding related party transactions.

CRITICAL ACCOUNTING POLICIES

The preparation of financial statements in conformity with Generally Accepted Accounting Principles (GAAP) requires management to make estimates and assumptions that affect reported amounts and related disclosures. Management considers an accounting estimate to be critical if it requires assumptions to be made that were uncertain at the time the estimate was made and changes in the estimate or different estimates that could have been used could have a material impact on the results of operations and financial position.

Pensions

The Company incurs significant costs in providing non-contributory defined pension benefits. The costs are measured using actuarial valuations that are dependent upon numerous factors derived from actual plan experience and assumptions of future plan experience.

Pension costs are impacted by actual employee demographics (including age, compensation levels and employment periods), the level of contributions made to the plan, earnings on plan assets and plan amendments. In addition, pension costs are also affected by changes in key actuarial assumptions, including anticipated rates of return on plan assets and the discount rates used in determining the projected benefit obligation and pension costs.

These assumptions are updated annually in accordance with Statement of Financial Accounting Standards (SFAS) No. 87, "Employers' Accounting for Pensions". In selecting an assumed discount rate, the prevailing market rate of fixed income debt instruments with maturities matching the expected timing of the benefit obligation was considered. The assumed rate of return on plan assets was developed based on the weighted average of long-term returns forecast for the expected portfolio mix of investments held by the plan. These assumptions are based on the Company's best estimates and judgment; however, material changes may occur if these assumptions differ from actual events. See Note 9 to the consolidated financial statements for information regarding the assumptions used to determine benefit obligations and net costs.

The following table reflects the sensitivities associated with a 0.5 percent increase or a 0.5 percent decrease in key actuarial assumptions. Each sensitivity reflects an evaluation of the change based solely on a change in that assumption only.

Actuarial assumption	Change in Assumption	Impact on Projected Benefit Obligation	Impact on Pension Liability	Impact on 2004 Pension Expense
			(millions)	
Discount rate	0.5% increase	$ (28.3)	$ (16.1)	$ (1.7)
Rate of return on plan assets	0.5% increase	-	-	(1.8)
Discount rate	0.5% decrease	30.3	18.6	1.8
Rate of return on plan assets	0.5% decrease	-	-	1.8

For the year ended December 31, 2004, the Company recorded pension expense of approximately $21.8 million, a $4.3 million increase from the prior year. Pension expense for 2005 is expected to approximate $27.0 million, a $5.2 million increase over 2004. The increase is primarily due to the amortization of investment losses from prior years that are recognized on a rolling five-year average basis and lower discount rates.

The Company's pension plan assets are primarily made up of equity and fixed income investments. The market value of the plan assets increased $29.5 million in 2004 reflecting continued improvement in the equity markets since the decline in 2002 and 2001. At plan year-end 2004, the fair value of pension plan assets was $370.5 million, not including a $20.7 million contribution made in 2004 after the plan year-end.

The total accumulated benefit obligation (ABO) of the plans exceeded the fair value of plan assets requiring the Company to record an additional minimum pension liability of $84.2 million including $79.8 million recorded at KCP&L. See Note 9 to the consolidated financial statements for additional information.

Market conditions and interest rates significantly affect the future assets and liabilities of the plan. It is difficult to predict future pension costs, the additional pension liability and cash funding requirements due to volatile market conditions; however, similar charges may be required in the future.

Regulatory Matters

As a regulated utility, KCP&L is subject to the provisions of SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." Accordingly, KCP&L has recorded assets and liabilities on its balance sheet resulting from the effects of the ratemaking process, which would not be recorded under GAAP if KCP&L were not regulated. Regulatory assets represent costs incurred that have been deferred because future recovery in customer rates is probable. Regulatory liabilities generally represent probable future reductions in revenue or refunds to customers. KCP&L's continued ability to meet the criteria for application of SFAS No. 71 may be affected in the future by competitive forces and restructuring in the electric industry. In the event that SFAS No. 71 no longer applied to all, or a separable portion, of KCP&L's operations, the related regulatory assets and liabilities would be written off unless an appropriate regulatory recovery mechanism is provided. Additionally, these factors could result in an impairment on utility plant assets as determined pursuant to SFAS No. 144, "Accounting for the Impairment or Disposal of Long-lived Assets." See Note 4 to the consolidated financial statements for a discussion of regulatory assets and liabilities.

Asset Retirement Obligations

Effective January 1, 2003, the Company adopted SFAS No. 143, "Accounting for Asset Retirement Obligations," which provides accounting requirements for the recognition and measurement of liabilities associated with the retirement of tangible long-lived assets.

The adoption of SFAS No. 143 changed the accounting for and the method used to report KCP&L's obligation to decommission its 47% share of Wolf Creek. The legal obligation to decommission Wolf Creek was incurred when the plant was placed in service in 1985. The estimated liability, recognized on KCP&L's balance sheet at January 1, 2003, is based on a third party nuclear decommissioning study conducted in 2002. KCP&L used a credit-adjusted risk free discount rate of 6.42% to calculate the retirement obligation. This estimated rate is based on the rate KCP&L could issue 30-year bonds, adjusted downward to reflect the portion of the anticipated costs in current year dollars that had been funded at date of adoption through a tax-qualified trust fund. The cumulative impact of prior decommissioning accruals recorded consistent with rate orders issued by the MPSC and KCC has been reversed and a new regulatory contra-asset for such amounts has been established. Amounts collected through these rate orders have been deposited in a legally restricted external trust fund.

KCP&L also must recognize, where possible to estimate, the future costs to settle other legal liabilities including the removal of water intake structures on rivers, capping/filling of piping at levees following steam power plant closures and capping/closure of ash landfills. Estimates for these liabilities are based on internal engineering estimates of third party costs to remove the assets in satisfaction of legal obligations and have been discounted using credit adjusted risk free rates ranging from 5.25% to 7.50% depending on the anticipated settlement date.

Revisions to the estimated liabilities of KCP&L could occur due to changes in the decommissioning or other cost estimates, extension of the nuclear operating license or changes in federal or state regulatory requirements. KCP&L has legal Asset Retirement Obligations (ARO) for certain other assets where it is not possible to estimate the time period when the obligations will be settled. Consequently, the retirement obligations cannot be measured at this time. See Note 16 to the consolidated financial statements for a discussion of ARO.

Although the liability for Wolf Creek decommissioning costs recorded under the ARO method is expected to be substantially the same at the end of Wolf Creek's life as the liability to be recorded pursuant to regulatory orders, the rate at which the liability increases varies under the different methods. Because KCP&L is subject to SFAS No. 71, the difference in the recognition of the liability will have no impact on net income.

Asset Impairment, including Goodwill and Other Intangible Assets

SFAS No. 144

Long-lived assets and intangible assets subject to amortization are periodically reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable as prescribed under SFAS No. 144.

During 2003, KLT Gas management determined that two gas properties were impaired as development activities indicated a decline in the estimates of future gas production. As a result of the lower estimated production, the carrying amount of each property exceeded its estimated fair value based upon discounted estimated future cash flows, which resulted in impairments on the two properties. Internal and third party models were used in the Company's estimate of future production volumes, natural gas pricing, capital expenditures and operating costs. Cash flow models were based on management's understanding of prospect geology, well costs and projected operating expenses. Natural gas pricing assumptions were based on the New York Mercantile Exchange Henry Hub Natural Gas forward curve, adjusted for basis differentials and other transportation charges.

Additionally in 2003, Great Plains Energy management performed a strategic review of the KLT Gas portfolio and operations. Management determined it would recommend a sale of the KLT Gas portfolio and a plan to exit the gas business at the February 2004 Board of Directors' meeting. As a result of its decision to recommend a sale of the KLT Gas portfolio and exit the gas business, Great Plains Energy management engaged a second third party firm to complete a market reference valuation analysis for the Company's use in determination of the fair value of the KLT Gas portfolio. As a result of the KLT Gas strategic review and market reference valuation analysis having been conducted, an impairment test of the entire KLT Gas portfolio was performed at December 31, 2003, in accordance with SFAS No. 144, using a probability weighting of the likelihood of potential outcomes at the February 2004 meeting. The impairment test considered 1) the scenario of sale of the entire KLT Gas portfolio with fair value based on estimated market prices and 2) the scenario of hold and use with fair value determined by risk adjusted discounted cash flows.

In February 2004, the Great Plains Energy Board of Directors approved management's recommendation to sell the KLT Gas portfolio and exit the gas business. As a result, the carrying amount of the KLT Gas portfolio was written down to its estimated realizable value. See Note 6 to the consolidated financial statements for a discussion of KLT Gas discontinued operations and SFAS 144 impairments.

SFAS No. 142

Great Plains Energy, through IEC, completed its purchase of an additional indirect interest in Strategic Energy during 2004. The Company recorded indefinite and finite lived intangible assets at fair value in accordance with SFAS No. 142, "Goodwill and Other Intangible Assets." Finite lived intangible assets are periodically reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable as prescribed under SFAS No. 144. Indefinite lived intangibles are tested for impairment at least annually and more frequently when indicators of impairment exist as prescribed under SFAS No. 142. See Note 8 to the consolidated financial statements for additional information.

Goodwill is tested for impairment at least annually and more frequently when indicators of impairment exist as prescribed under SFAS No. 142. SFAS No. 142 requires that if the fair value of a reporting unit is less than its carrying value including goodwill, the implied fair value of the reporting unit goodwill must be compared with its carrying value to determine the amount of impairment. Strategic Energy's 2004 annual impairment test was completed as of September 1, the annual review date, and there was no impairment of the Strategic Energy goodwill. See Note 5 to the consolidated financial statements for information regarding the impact of adopting SFAS No. 142 on goodwill and goodwill amortization.

The accounting estimates related to impairment analyses are subject to change from period to period because management is required to make assumptions about future sales, operating costs and discount rates over an indefinite life. Actual margins and volumes have fluctuated and, to a great extent, fluctuations are expected to continue. The estimates of future margins are based upon internal budgets, which incorporate estimates of customer growth, business expansion and weather trends, among other items.

Strategic Energy – Energy and Energy-related Contract Accounting
Strategic Energy primarily purchases power under forward physical delivery contracts to supply electricity to its retail energy customers under full requirement sales contracts. Both the forward purchase contracts and the full requirements sales contracts meet the accounting definition of a derivative; however, on a majority of the forward purchase derivative contracts and all of the full requirement sales contracts, Strategic Energy applies the normal purchases and normal sales exception (NPNS) accounting treatment. Accordingly, Strategic Energy records receivables and revenues generated from the sales contracts as energy is delivered and consumed by the retail customer. Likewise, a liability and purchase power expense are recorded when the energy under forward physical delivery contracts is delivered to Strategic Energy's retail customers.

An inability to sustain the NPNS accounting treatment for forward purchase derivative contracts could result in asymmetrical accounting, whereby the timing of the impact on operating income would differ if NPNS accounting treatment was applied to the full requirements sales contracts, but the forward purchase derivative contracts no longer qualified for NPNS accounting treatment.

For forward purchase contracts that do not meet the qualifying criteria for NPNS accounting treatment, Strategic Energy elects cash flow hedge accounting where appropriate. Under cash flow hedge accounting, the fair value of the contract is recorded as a current or long-term derivative asset or liability. Subsequent changes in the fair value of the derivative assets and liabilities are recorded on a net basis in OCI and subsequently reclassified as purchased power expense in Great Plains Energy's consolidated statement of income as the power is delivered and/or the contract settles. Additionally, in the future, OCI may have greater fluctuations than historically because of a larger number of derivative contracts designated for cash flow hedge accounting, but these fluctuations would not affect current period operating income or cash flows.

Changes in fair value of forward purchase derivative contracts that do not meet the requirements for the NPNS accounting treatment or cash flow hedge accounting are recorded in operating income and as a current or long-term derivative asset or liability. The subsequent changes in the fair value of these contracts could result in operating income volatility as the fair value of the changes in the associated derivative assets and liabilities are recorded on a net basis in purchased power expense in Great Plains Energy's consolidated statement of income.

Derivative assets and liabilities consist of a combination of energy and energy-related contracts. While some of these contracts represent commodities or instruments for which prices are available from external sources, other commodities and certain contracts are not actively traded and are valued using modeling techniques to determine expected future market prices. The market prices used to determine fair value reflect management's best estimate considering time, volatility and historical trends. However, future market prices will vary from those used in recording energy assets and liabilities at fair value, and it is possible that such variations could be significant.

Market prices for energy and energy-related commodities vary based upon a number of factors. Changes in market prices will affect the recorded fair value of energy contracts. Changes in the fair value of energy contracts will affect operating income in the period of the change for contracts under fair value accounting and OCI in the period of change for contracts under cash flow hedge accounting, while changes in forward market prices related to contracts under accrual accounting will affect operating income in future periods to the extent those prices are realized. Strategic Energy cannot predict whether, or to what extent, the factors affecting market prices may change, but those changes could be material and could be either favorable or unfavorable.

GREAT PLAINS ENERGY RESULTS OF OPERATIONS

The following table summarizes Great Plains Energy's comparative results of operations.

	2004	2003	2002
		(millions)	
Operating revenues	$ 2,464.0	$ 2,148.0	$ 1,802.3
Fuel	(179.4)	(160.3)	(159.7)
Purchased power - KCP&L	(52.5)	(53.2)	(46.2)
Purchased power - Strategic Energy	(1,247.5)	(968.9)	(685.4)
Other operating expenses	(510.6)	(479.2)	(465.1)
Depreciation and amortization	(150.1)	(142.8)	(146.8)
Gain (loss) on property	(5.1)	23.7	1.4
Operating income	318.8	367.3	300.5
Non-operating income (expenses)	(8.4)	(13.0)	(13.1)
Interest charges	(83.0)	(76.2)	(87.4)
Income taxes	(54.5)	(78.6)	(51.3)
Minority interest in subsidiaries	2.1	(7.8)	(10.8)
Loss from equity investments	(1.5)	(2.0)	(1.2)
Income from continuing operations	173.5	189.7	136.7
Discontinued operations	7.3	(44.8)	(7.5)
Cumulative effect of a change in accounting principle	-	-	(3.0)
Net income	180.8	144.9	126.2
Preferred dividends	(1.6)	(1.6)	(1.7)
Earnings available for common stock	$ 179.2	$ 143.3	$ 124.5

Great Plains Energy's 2004 earnings, as detailed in the following table, increased to $179.2 million, or $2.49 per share, from $143.3 million, or $2.07 per share in 2003. The issuance of 5.0 million shares in June 2004 diluted 2004 EPS by $0.10.

	Earnings			Earnings Per Great Plains Energy Share		
	2004	2003	2002	2004	2003	2002
		(millions)				
KCP&L	$ 150.0	$ 127.2	$ 102.9	$ 2.08	$ 1.84	$ 1.64
Subsidiary operations	(6.7)	(1.3)	(0.2)	(0.09)	(0.02)	-
Discontinued operations (RSAE)	-	(8.7)	(4.0)	-	(0.13)	(0.06)
Cumulative effect of a change in accounting principle	-	-	(3.0)	-	-	(0.05)
Consolidated KCP&L	143.3	117.2	95.7	1.99	1.69	1.53
Strategic Energy	42.5	39.6	29.7	0.59	0.57	0.48
Other non-regulated operations	(12.3)	24.2	4.3	(0.17)	0.35	0.07
Discontinued operations (KLT Gas)	7.3	(36.1)	(3.5)	0.10	(0.52)	(0.06)
Preferred dividends	(1.6)	(1.6)	(1.7)	(0.02)	(0.02)	(0.03)
Great Plains Energy	$ 179.2	$ 143.3	$ 124.5	$ 2.49	$ 2.07	$ 1.99

The earnings per share of any segment does not represent a direct legal interest in the asset and liabilities allocated to any one segment but rather represents a direct equity interest in Great Plains Energy's assets and liabilities as a whole.

The increase in Great Plains Energy's 2004 earnings is primarily due to an increase in KCP&L's wholesale MWhs sold at higher wholesale prices, the May 2004 purchase of an additional 11.45% indirect interest in Strategic Energy and a $10.8 million favorable impact of state tax planning on the composite tax rate for the Company. The increase in KCP&L's wholesale MWh sales was primarily due to increased generation, bundling transmission with energy and lower retail loads during the summer months. The Great Plains Energy earnings increase was offset by an increase in operating expenses at KCP&L and Strategic Energy, a $5.3 million impairment related to the first quarter 2005 sale of Worry Free, the net effect on 2003 earnings of the Hawthorn No. 5 litigation settlements and the $28.1 million net gain in 2003 related to the DTI bankruptcy. Additionally, a continuing environment of higher and less volatile energy prices and flat to higher forward electricity prices continue to negatively impact Strategic Energy's average gross margins. Discontinued operations (KLT Gas) primarily reflect the gain on sales of assets in 2004 and the loss due to the impairment related to the exit of the business in 2003. Discontinued operations (RSAE) primarily reflect the loss on the sale of RSAE in 2003.

Great Plains Energy's 2003 earnings increased to $143.3 million, or $2.07 per share, from $124.5 million, or $1.99 per share in 2002. The issuance of 6.9 million shares in November 2002 diluted 2003 EPS by $0.23. The increase in Great Plains Energy's 2003 earnings is primarily due to an increase in wholesale MWh sales, partial settlements of the Hawthorn No. 5 litigation, the fourth quarter 2002 purchase of an additional 6.0% indirect interest in Strategic Energy and the $28.1 million net gain related to the DTI bankruptcy. The increase in wholesale revenues was partially offset by the effect on retail revenues of the January 2003 Kansas rate reduction. In 2003, discontinued operations (KLT Gas) reflect an operating loss, property impairments and impairments related to the exit of the business. Discontinued operations (RSAE) primarily reflect the loss on the sale of RSAE in 2003.

Great Plains Energy's projected net income is expected to decrease in 2005. The decrease in projected net income for 2005 is due to a significant increase in fuel costs at KCP&L, lower anticipated 2005 average gross margins at Strategic Energy, expiration of a portion of the Company's investment tax credits in 2005 and the absence of the 2004 impact of the lower composite tax rate on deferred tax balances. These factors are projected to more than offset projected retail load growth and operational expense savings at KCP&L as well as lower holding company losses in 2005.

CONSOLIDATED KCP&L RESULTS OF OPERATIONS

The following discussion of consolidated KCP&L results of operations includes KCP&L, an integrated electric utility and HSS, an unregulated subsidiary of KCP&L. References to KCP&L, in the discussion that follows, reflect only the operations of the integrated electric utility. The following table summarizes consolidated KCP&L's comparative results of operations.

	2004	2003	2002
		(millions)	
Operating revenues	$ 1,091.6	$ 1,057.0	$ 1,012.8
Fuel	(179.4)	(160.3)	(159.7)
Purchased power	(52.5)	(53.2)	(46.2)
Other operating expenses	(442.3)	(422.6)	(411.6)
Depreciation and amortization	(145.2)	(141.0)	(145.5)
Gain (loss) on property	(5.1)	1.6	0.2
Operating income	267.1	281.5	250.0
Non-operating income (expenses)	(1.9)	(3.1)	(4.1)
Interest charges	(74.2)	(70.3)	(80.3)
Income taxes	(52.8)	(83.5)	(62.9)
Minority interest in subsidiary	5.1	1.3	-
Income from continuing operations	143.3	125.9	102.7
Discontinued operations	-	(8.7)	(4.0)
Cumulative effect of a change in accounting principle	-	-	(3.0)
Net income	$ 143.3	$ 117.2	$ 95.7

Consolidated KCP&L's income from continuing operations increased $17.4 million in 2004 compared to 2003. Consolidated KCP&L's operating revenues increased $34.6 million in 2004 compared to 2003, primarily due to a 14% increase in KCP&L's wholesale MWhs sold and a 13% increase in the average wholesale market price. The increase in wholesale MWhs sold was primarily due to increased generation, bundling transmission with energy and lower than expected retail loads during the summer months. An increase in operating expenses more than offset these factors primarily due to the increase in MWhs generated, including higher coal and coal transportation costs, higher administrative expenses, a $7.3 million impairment charge related to the first quarter 2005 sale of Worry Free and the significant positive impact on 2003 of the Hawthorn No. 5 litigation settlements. Income taxes decreased due to the $10.1 million favorable impact of state tax planning on the composite tax rate and a $5.9 million allocation of tax benefits from holding company losses pursuant to the Company's intercompany tax allocation agreement.

As described in Item 3. Legal Proceedings, KCP&L filed suit against multiple defendants who are alleged to have responsibility for the 1999 Hawthorn No. 5 boiler explosion. KCP&L and its primary insurance company have entered into a subrogation allocation agreement under which recoveries in this suit are generally allocated 55% to the primary insurance company and 45% to KCP&L. Various defendants have settled with KCP&L in this litigation, resulting in KCP&L recording $2.4 million and $35.8 million in 2004 and 2003, respectively, under the terms of the subrogation allocation agreement. A portion of the settlements, $1.2 million and $17.3 million, for 2004 and 2003, respectively, was recorded as a recovery of capital expenditures. The following table summarizes the income statement impact related to the remainder of the settlements for loss of use of Hawthorn No. 5.

	2004	2003
	(millions)	
Wholesale revenues	$ 0.2	$ 2.7
Fuel	0.2	4.0
Purchased power	0.8	11.8
Operating income	1.2	18.5
Income taxes	(0.5)	(7.2)
Net income	$ 0.7	$ 11.3

Consolidated KCP&L's income from continuing operations increased $23.2 million in 2003 compared to 2002. Consolidated KCP&L's operating revenues increased $44.2 million primarily due to a significant increase in wholesale MWhs sold at higher wholesale prices partially offset by the effect on retail revenues of the January 2003 Kansas rate reduction. Wholesale MWhs sold increased 16% in 2003 primarily due to increased generation and a more focused sales effort. Additionally, the average market price increased 33% primarily due to higher natural gas prices. Revenues also increased due to the partial settlements of Hawthorn No. 5 litigation. This increase in revenues combined with decreases in interest expense and depreciation expense more than offset increases in purchased power, pension, power plant maintenance and transmission expenses. The amortization of the Missouri jurisdictional portion of the January 2002 storm costs increased $3.1 million in 2003. In 2002, KCP&L expensed $16.5 million for the Kansas jurisdictional portion of the January 2002 storm costs.

Discontinued operations in 2003 includes a $7.1 million loss on the June 2003 disposition of HSS' interest in RSAE and continuing losses through the date of disposition of $1.6 million. Additionally, 2002 net income reflects the $3.0 million cumulative effect to January 1, 2002, of a change in accounting principle for the adoption of SFAS No. 142 and the associated write-down of RSAE goodwill.

Consolidated KCP&L's net income is projected to decrease in 2005 primarily due to a significant increase in fuel costs and the absence of the 2004 impact of the lower composite tax rate on deferred tax balances. These factors are projected to more than offset projected retail load growth and operational expense savings at KCP&L.

Consolidated KCP&L Sales Revenues and MWh Sales

	2004	% Change	2003	% Change	2002
Retail revenues			(millions)		
Residential	$ 347.1	(4)	$ 361.5	(2)	$ 367.4
Commercial	421.1	1	417.6	-	418.6
Industrial	96.2	1	95.0	1	93.7
Other retail revenues	8.7	1	8.7	-	8.6
Total retail	873.1	(1)	882.8	(1)	888.3
Wholesale revenues	200.2	27	157.5	46	108.0
Other revenues	16.8	15	14.6	8	13.6
KCP&L electric revenues	1,090.1	3	1,054.9	4	1,009.9
Subsidiary revenues	1.5	(25)	2.1	(28)	2.9
Consolidated KCP&L revenues	$ 1,091.6	3	$ 1,057.0	4	$ 1,012.8

	2004	% Change	2003	% Change	2002
Retail MWh sales			(thousands)		
Residential	4,903	(3)	5,047	1	5,004
Commercial	6,998	1	6,933	-	6,902
Industrial	2,058	1	2,035	3	1,968
Other retail MWh sales	85	-	85	2	83
Total retail	14,044	-	14,100	1	13,957
Wholesale MWh sales	6,603	14	5,777	16	4,969
KCP&L electric MWh sales	20,647	4	19,877	5	18,926

Retail revenues decreased $9.7 million in 2004 compared to 2003 primarily due to a $14.4 million reduction in residential revenues. Residential usage per customer decreased 4% in 2004 compared to 2003 as a result of significantly cooler summer weather in 2004. The Kansas City area experienced one of the coolest summers in the past 30 years, which resulted in cooling degree days 18% below normal. Weather most significantly affects residential customers' usage patterns. The impact of the cooler summer weather was partially offset by continued load growth in 2004. Load growth consists of higher usage per customer and the addition of new customers. The average number of residential and commercial customers continues to grow; both increased 1% to 2% in 2004 and 2003 compared to the respective prior years. Retail revenues decreased $5.5 million in 2003 compared to 2002. The Kansas rate reduction effective January 1, 2003, decreased 2003 retail revenues approximately $12.5 million and was partially offset by load growth in 2003.

Bulk power sales, the major component of wholesale sales, vary with system requirements, generating unit and purchased power availability, fuel costs and requirements of other electric systems. Wholesale revenues increased $42.7 million in 2004. Wholesale MWhs sold increased 14% in 2004 compared to 2003, primarily due to increased generation, bundling transmission with energy and lower than expected retail loads during the summer months, combined with successful marketing efforts. KCP&L's coal fleet equivalent availability factor increased to 84% in 2004 compared to 82% for 2003, which contributed to an increased volume of wholesale MWhs available to sell. Average market prices per MWh increased 13% to $30.72 in 2004 compared to 2003, primarily due to more sales made during periods of higher natural gas prices and bundling transmission with energy to provide a delivered product. Additionally, wholesale revenues were affected by the partial settlements of the Hawthorn No. 5 litigation. Wholesale revenues increased $49.5 million in 2003 compared to 2002, which in 2003 included $2.7 million related to the partial settlements of Hawthorn No. 5 litigation. Wholesale MWhs sold increased 16% in 2003 compared to 2002, primarily due to increased generation and a more focused sales effort. The revenue variance in 2003 compared to 2002 was primarily due to a 33% increase in average market price per MWh of power sold in 2003 to $27.27. The increase was driven by higher natural gas prices. Less than 1% of revenues reflect rates that include an automatic fuel adjustment provision.

Consolidated KCP&L Fuel and Purchased Power
The fuel cost per MWh generated and the purchased power cost per MWh has a significant impact on the results of operations for KCP&L. Generation fuel mix can change the fuel cost per MWh generated substantially. In 2004, KCP&L experienced a record coal base load capacity factor of 80%. The coal fleet achieved a record level of generation of approximately 16 million MWhs, a 5% increase compared to 2003. Nuclear fuel costs per MWh generated remain substantially less than the cost of coal per MWh generated. Coal has a significantly lower cost per MWh generated than natural gas and oil. Fossil plants averaged over 75% of total generation and the nuclear plant the remainder over the last three years. Replacement power costs for planned Wolf Creek outages are accrued evenly over the unit's operating cycle. KCP&L expects its cost of nuclear fuel to remain relatively stable through the year 2009. The cost per MWh for purchased power is still significantly higher than the fuel cost per MWh of coal and nuclear generation. KCP&L continually evaluates its system requirements, the availability of generating units, availability and cost of fuel supply, availability and cost of purchased power and the requirements of other electric systems to provide reliable power economically.

Fuel expense increased $19.1 million in 2004 compared to 2003 primarily due to a 6% increase in MWhs generated, higher coal and coal transportation costs, higher natural gas costs and the net effect of $3.8 million from the Hawthorn No. 5 partial litigation settlements. The increase was partially offset by a lower average fuel cost per MWh generated due to increased coal and nuclear fuel and less natural gas in the fuel mix. The change in fuel mix was primarily due to the 2003 refueling outage at Wolf Creek and the cooler 2004 summer weather, which allowed coal and nuclear capacity to supply a greater percentage of the reduced retail load. Fuel expense increased $0.6 million in 2003 compared to 2002 primarily due to a 3% increase in MWhs generated. This increase was partially offset by a lower average fuel cost per MWh generated due to increased coal and less natural gas in the fuel mix and a $4.0 million decrease related to the partial settlements of Hawthorn No. 5 litigation.

Purchased power expense decreased $0.7 million in 2004 compared to 2003. MWhs purchased decreased 31% in 2004 compared to 2003 primarily due to lower retail customer demand and a 2% increase in the coal fleet equivalent availability factor in 2004 compared to 2003. The decrease in MWhs purchased was partially offset by an 11% increase in the average purchased power price per MWh in 2004 compared to 2003 primarily due to higher natural gas market prices and increased demand in the market area earlier in 2004. Another offset includes the net effect of the Hawthorn No. 5 partial litigation settlements, which impacted purchased power expense by $11.0 million in 2004 compared to 2003. Purchased power expense increased $7.0 million in 2003 compared to 2002 primarily due to a 31% increase in the price per MWh driven primarily by increased natural gas prices. MWhs purchased increased 27% in 2003 compared to 2002 due to increased customer needs. These increases were partially offset by the $11.8 million related to the Hawthorn No. 5 litigation settlements in 2003.

KCP&L expects its fuel expense to increase significantly in 2005 due to projected increases in the cost of coal and coal transportation and in the volume and price of natural gas generation in the fuel mix. KCP&L expects to utilize its natural gas-fired peaking generating capacity more often to serve expected growth in retail customer demand, which will increase natural gas consumption. High natural gas and fuel oil costs are also influencing the price of coal and coal transportation costs, which are also expected to increase. The anticipated increase in delivered coal prices is expected to affect most utilities; therefore, the increase is not expected to materially erode KCP&L's position as a low cost regional electricity generator.

Consolidated KCP&L Other Operating Expenses *(including other operating, maintenance and general taxes)*
Consolidated KCP&L's other operating expenses increased $19.7 million in 2004 compared to 2003 primarily due to the following:

- increased pension expense of $3.5 million primarily due to lower discount rates, the amortization of investment losses from prior years and plan settlement losses,
- increased other employee-related costs of $3.5 million including higher medical costs and incentive compensation costs,
- increased property taxes of $4.3 million primarily due to increases in assessed property valuations and mill levies,
- increased outside services of $4.4 million including costs associated with Sarbanes-Oxley compliance,
- increased transmission and distribution expenses including $2.5 million primarily due to increased transmission usage charges as a result of the increased wholesale MWh sales, $2.3 million related to SPP administration and $1.3 million in storm related expenses and
- increased office expense including a $2.1 million expenditure to buy out computer equipment operating leases.

Partial offsets to the increase in other operating expenses included:

- decreased plant maintenance expense of $1.3 million primarily due to differences in timing and scope of outages and $0.9 million in lower gross receipts taxes as a result of lower retail revenues and
- decreased expenses due to the reversal of an environmental accrual and the establishment of a regulatory asset for the probable recovery in the Kansas jurisdiction of enhanced security costs.

Consolidated KCP&L's other operating expenses increased $11.0 million in 2003 compared to 2002 primarily due to the following:

- amortizing an additional $3.1 million of the Missouri jurisdictional portion of the January 2002 ice storm in 2003,
- increased pension expense of $11.3 million primarily due to a significant decline in the market value of plan assets,
- increased plant maintenance expense of $6.7 million for plant outages,
- increased transmission expenses of $3.3 million primarily due to increased usage charges as a result of the increased wholesale MWh sales and increased MWh of purchased power,
- partially offsetting the increases were lower maintenance expense in 2003 due to expensing in 2002 the $16.5 million of the Kansas jurisdictional portion of the January 2002 ice storm.

Consolidated KCP&L Depreciation and Amortization
Consolidated KCP&L's depreciation and amortization expense increased $4.2 million in 2004 compared to 2003. The increases are primarily due to an increase of $2.6 million related to capital additions and $3.8 million as a result of the consolidation of the Lease Trust. The increase was partially offset by $1.9 million as a result of certain software becoming fully amortized in 2003.

Consolidated KCP&L's depreciation expense decreased $4.5 million in 2003 compared to 2002. Depreciation expense decreased approximately $7.7 million due to the change to a 60-year life for Wolf Creek pursuant to the 2002 KCC stipulation and agreement. See Note 4 to the consolidated financial statements for additional information. This decrease was partially offset by increased depreciation expense of $2.2 million related to capital additions and $1.3 million as a result of the consolidation of the Lease Trust.

Consolidated KCP&L Interest Charges

Consolidated KCP&L's interest charges increased $3.9 million in 2004 compared to 2003. The increase was primarily due to a $10.1 million interest component related to the IRS 1995-1999 audit settlement. Partially offsetting this increase was a $6.3 million decrease primarily due to the 2004 redemption of KCP&L's $154.6 million 8.3% Junior Subordinated Deferred Interest Bonds. See Notes 11 and 19 to the consolidated financial statements for further information.

Consolidated KCP&L's interest charges decreased $10.0 million in 2003 compared to 2002. KCP&L's long-term debt interest expense decreased $9.3 million in 2003 compared to 2002 primarily due to lower levels of outstanding long-term debt as a result of the repayment of $124.0 million of medium-term notes in 2003. Lower average interest rates in 2003 compared to 2002 also contributed to the decrease.

Consolidated KCP&L Income Taxes

Consolidated KCP&L's income taxes decreased $30.7 million in 2004 compared to 2003. Several factors contributed to the decreased taxes including lower income in 2004 compared to 2003. The favorable impact of state tax planning on the composite tax rate decreased income taxes $10.1 million, including $8.6 million reflecting the composite tax rate change on deferred tax balances resulting from book to tax temporary differences. An additional $10.1 million decrease is attributable to the reserves for the interest component of the IRS 1995-1999 audit settlement, which offset interest expense and had no impact on income from continuing operations. Income taxes also decreased by $5.9 million due to the allocation of tax benefits from holding company losses pursuant to the Company's intercompany tax allocation agreement. Income taxes increased $20.6 million in 2003 compared to 2002, primarily due to higher income.

On October 22, 2004, the American Jobs Creation Act of 2004 (AJCA) became law. Most significantly, the AJCA contains a provision that allows for a tax deduction of 9% (3% for 2005-2006; 6% for 2007-2009; 9% thereafter) of qualified production activities income. Income from electric generation activities is included in the definition of qualified production activities. Because of its electric generation activities, KCP&L expects to be favorably impacted by the AJCA. The IRS has recently issued interim guidance on which KCP&L may rely on until regulations are issued. KCP&L is reviewing the recent guidance and has made preliminary estimates of the deduction. For 2005, the deduction is estimated to be approximately $6 million. The regulatory treatment regarding the qualified production deduction is unknown at this time.

STRATEGIC ENERGY RESULTS OF OPERATIONS

The following table summarizes Strategic Energy's comparative results of operations.

	2004	2003	2002
		(millions)	
Operating revenues	$ 1,372.4	$ 1,091.0	$ 789.5
Purchased power	(1,247.5)	(968.9)	(685.4)
Other operating expenses	(51.3)	(42.1)	(37.6)
Depreciation and amortization	(4.8)	(1.7)	(0.9)
Operating income	68.8	78.3	65.6
Non-operating income (expenses)	1.7	1.0	0.4
Interest charges	(0.7)	(0.4)	(0.3)
Income taxes	(24.3)	(30.2)	(25.2)
Minority interest	(3.0)	(9.1)	(10.8)
Net income	$ 42.5	$ 39.6	$ 29.7

Strategic Energy's net income increased $2.9 million in 2004 compared to 2003. Retail MWhs delivered increased 22% in 2004 compared to 2003. Great Plains Energy, through IEC, completed the purchase of an additional 11.45% indirect interest in Strategic Energy resulting in a $1.8 million increase in net income. Income taxes decreased in 2004 primarily due to a $3.1 million allocation of tax benefits from holding company losses pursuant to the Company's intercompany tax allocation agreement and the Company's income tax accounting policies for segment reporting. The increase to net income was partially offset by a 16% decline in the average gross margin per MWh (revenues less purchased power divided by MWhs delivered) to $6.15 in 2004. The decline in gross margin is primarily due to the roll-off of older, higher margin contracts, price discounts driven by a more competitive market and persistently higher commodity prices, and a $4.2 million increase in tax reserves. A continuing environment of higher and less volatile energy prices and flat to higher forward electricity prices continue to negatively impact the average gross margins. The negative impacts on average gross margin per MWh were partially offset by a $1.7 million change in fair value related to energy contracts that do not qualify for hedge accounting and from hedge ineffectiveness.

Strategic Energy's net income increased $9.9 million in 2003 compared to 2002. The increased net income was primarily due to growth in retail electric revenues from the expansion into new markets and continued sales efforts in existing markets. In addition, Great Plains Energy increased its indirect interest in Strategic Energy by 6% in the fourth quarter of 2002. These increases were partially offset by increased general and administrative expenses including employee related expenses. Also, the average gross margin per MWh decreased to $7.34 in 2003 compared to $8.70 in 2002. The decrease in average gross margin per MWh in 2003 compared to 2002 was primarily due to the roll-off of higher margin contracts that were obtained during periods of high market price volatility in late 2000 and early 2001 and to a lesser extent market conditions, including increased competition.

Strategic Energy's net income is projected to decrease in 2005. The projected decrease in average gross margins per MWh to a range of $4.60 to $5.00 in 2005 from $6.15 in 2004 is anticipated to more than offset the expected increase in MWhs delivered from 20.3 million in 2004 to a range of 21 to 23 million in 2005.

Strategic Energy Operating Revenues
Operating revenues from Strategic Energy increased $281.4 million in 2004 compared to 2003 and $301.5 million in 2003 compared to 2002 as shown in the following table.

	2004	% Change	2003	% Change	2002
			(millions)		
Electric - Retail	$ 1,355.3	27	$ 1,063.2	40	$ 759.5
Electric - Wholesale	15.5	(41)	26.5	(8)	28.8
Professional services	1.6	18	1.3	14	1.2
Total operating revenues	$ 1,372.4	26	$ 1,091.0	38	$ 789.5

Retail electric revenues increased $292.1 million in 2004 compared to 2003 primarily due to increased retail MWhs delivered. Retail MWhs delivered increased 22% to 20.3 million in 2004 compared to 2003. The increased MWhs delivered resulted primarily from strong sales efforts in customer retention as well as enrolling new customers primarily in Michigan and Texas where Strategic Energy continued to experience favorable conditions for growth. Strategic Energy's customer accounts totaled over 54,000 accounts at the end of 2004, a 14% increase from approximately 48,000 accounts at the end of 2003. Several factors contribute to changes in the average retail price per MWh, including the underlying electricity price, the nature and type of products offered and the mix of sales by geographic market. Average retail revenues per MWh increased 4% in 2004 compared to 2003 primarily due to a higher underlying electricity price that was driven by higher natural gas prices partially offset by price discounts driven by a more competitive market and persistently higher commodity prices.

Retail electric revenues increased $303.7 million in 2003 compared to 2002 primarily due to increased retail MWhs delivered. Retail MWhs delivered increased 41% to 16.6 million in 2003 from 11.8 million in 2002. The increased MWhs delivered resulted primarily from effective sales efforts in re-signing approximately 80% of existing customers as well as enrolling new customers in markets in which Strategic Energy continued to experience favorable conditions for growth. Customer accounts at the end of 2003 increased 44% from approximately 33,000 accounts at the end of 2002. MWhs delivered in California increased 70% to 5.5 million in 2003 and MWhs delivered in Texas increased 58% to 4.5 million in 2003 compared to 2002.

Strategic Energy Purchased Power
Strategic Energy primarily purchases power under forward physical delivery contracts to supply electricity to its retail energy customers based on projected usage. Strategic Energy sells any excess retail supply of electricity back into the wholesale market. The proceeds from the sale of excess supply of electricity are recorded as a reduction of purchased power. The amount of excess retail supply sales that reduced purchased power was $265.2 million, $160.4 million and $126.4 million in 2004, 2003 and 2002, respectively.

Strategic Energy utilizes derivatives including forward physical delivery contracts in the procurement of electricity. Changes in the fair value of derivative instruments that do not qualify for hedge accounting and cash flow hedge ineffectiveness reduced purchased power expense by $1.7 million in 2004 and were insignificant for 2003 and 2002.

As previously discussed, Strategic Energy operates in several retail choice electricity markets. The cost of supplying electricity to retail customers can vary widely by geographic market. This variability can be affected by many factors including, among other items, geographic differences in the cost per MWh of purchased power and capacity charges due to regional purchased power availability and requirements of other electricity providers and differences in transmission charges.

Purchased power expense increased $278.6 million in 2004 compared to 2003 primarily due to increased MWhs delivered as discussed above. Additionally, average prices per retail MWh purchased increased 7% in 2004 primarily due to the effect of the persistent environment of relatively high natural gas prices, increased competition, increased supply costs on certain contracts caused by customers selecting variable pricing mechanisms and increased tax reserves partially offset by the change in fair value of derivative instruments. Purchased power increased $283.5 million in 2003 compared to 2002 primarily due to increased MWhs delivered.

Strategic Energy Other Operating Expenses
Strategic Energy's other operating expenses as a percentage of operating revenues decreased to 3.7% in 2004 from 3.9% and 4.8% in 2003 and 2002, respectively, due to Strategic Energy's efforts in leveraging its infrastructure and the effects of achieving economies of scale. Strategic Energy's other operating expenses increased $9.2 million in 2004 compared to 2003; a 22% increase driven mainly by higher staffing levels associated with the continued growth of Strategic Energy. Additionally, higher consulting expenses associated with new software development initiatives and higher general tax expenses primarily due to higher capital stock and franchise tax rates increased other operating expenses.

Other operating expenses increased $4.5 million in 2003 compared to 2002 primarily due to higher staffing levels and higher other general and administrative expenses associated with higher sales volumes, geographic market expansion, and regulatory and market development initiatives.

Strategic Energy Income Taxes
Strategic Energy's income taxes decreased $5.9 million in 2004 compared to 2003 reflecting lower income and additional tax benefits. The additional benefits included $3.1 million due to the allocation of tax benefits from holding company losses pursuant to the Company's intercompany tax allocation agreement and a slight decrease due to the favorable impact of state tax planning on the composite tax rate. Strategic Energy's income taxes increased $5.0 million in 2003 compared to 2002 primarily reflecting higher income.

Strategic Energy Minority Interest
Minority interest represents the share of Strategic Energy's net income not attributable to Great Plains Energy's indirect ownership interest in Strategic Energy. Minority interest decreased $6.1 million in 2004 compared to 2003 primarily due to IEC's acquisition of an additional 11.45% indirect interest in Strategic Energy in May 2004. Minority interest decreased $1.7 million in 2003 compared to 2002 primarily due to IEC's acquisition of a 6% indirect ownership interest in Strategic Energy during the fourth quarter of 2002.

OTHER NON REGULATED ACTIVITIES

Investment in Affordable Housing Limited Partnerships - KLT Investments
KLT Investments Inc.'s (KLT Investments) net income in 2004 totaled $11.2 million (including an after tax reduction of $4.6 million in its affordable housing investment) compared to net income of $8.1 million in 2003 (including an after tax reduction of $6.7 million in its affordable housing investment) and net income of $10.4 million in 2002 (including an after tax reduction of $5.7 million in its affordable housing investment).

On a quarterly basis, KLT Investments compares the cost of properties accounted for by the cost method to the total of projected residual value of the properties and remaining tax credits to be received. Based on the latest comparison, KLT Investments reduced its investments in affordable housing limited partnerships by $7.5 million, $11.0 million and $9.0 million in 2004, 2003 and 2002, respectively. Pre-tax reductions in affordable housing investments are estimated to be $10 million, $1 million and $2 million in 2005 through and 2007, respectively. These projections are based on the latest information available but the ultimate amount and timing of actual reductions could be significantly different from the above estimates. The properties underlying the partnership investment are subject to certain risks inherent in real estate ownership and management. Even after these estimated reductions, net income from the investments in affordable housing is expected to be positive for 2005 through 2007.

KLT Investments accrued tax credits related to its investments in affordable housing limited partnerships of $18.3 million, $19.1 million and $19.3 million in 2004, 2003 and 2002, respectively. KLT Investments' estimates tax credits will be $16 million, $10 million and $6 million for 2005 through 2007, respectively, and continue to decline through 2009.

DTI Bankruptcy

On December 31, 2001, a subsidiary of KLT Telecom, DTI Holdings, Inc. and its subsidiaries, Digital Teleport, Inc. and Digital Teleport of Virginia, Inc., filed separate voluntary petitions in the Bankruptcy Court for the Eastern District of Missouri for reorganization under Chapter 11 of the U.S. Bankruptcy Code, which cases were procedurally consolidated. DTI Holdings and its two subsidiaries are collectively called "DTI". In December 2002, Digital Teleport entered into an agreement to sell substantially all of its assets to CenturyTel Fiber Company II, LLC, a nominee of CenturyTel, Inc, which was approved by the Bankruptcy Court, and closed in 2003.

The Company recorded a net gain of $28.1 million or $0.41 per share in 2003 related to the DTI bankruptcy. The impact on 2003 net income was primarily due to the net effect of the Chapter 11 plan confirmation and the resulting distribution, the reversal of a $15.8 million tax valuation allowance and the reversal of $5 million debtor in possession financing previously reserved.

Holding Company Income Taxes

The Company maintains an intercompany tax allocation agreement among the companies that file a consolidated or combined income tax return. Tax benefits from holding company losses are allocated to the subsidiaries based on income and these allocations are reflected in each segment's provision for income taxes. Holding company income taxes increased $6.5 million in 2004 compared to 2003 primarily to reflect the allocation of tax benefits pursuant to the Company's intercompany tax allocation agreement.

KLT GAS DISCONTINUED OPERATIONS

In February 2004, the Great Plains Energy Board of Directors approved management's recommendation to sell the KLT Gas portfolio and exit the gas business. The Company evaluated this business and determined the amount of capital and the length of time required for development of reserves and production, combined with the income volatility of the exploration process, were no longer compatible with the Company's strategic vision.

In 2004, KLT Gas completed sales of substantially all of the KLT Gas portfolio for $23.5 million cash, net of $1.4 million of transaction costs. The gain on the KLT Gas portfolio asset sales totaled $10.3 million, or $0.14 per share. The impact of the gain was partially offset by the loss from the wind down operations of $1.8 million in 2004. Additionally, the 2004 write down of the KLT Gas portfolio to its estimated net realizable value reduced net income by $1.2 million. Loss from discontinued operations in 2003 was $36.1 million including after tax impairments of $33.5 million and after tax operating losses of $2.6 million. See Note 6 to the consolidated financial statements for additional information and see Note 15 to the consolidated financial statements for information regarding a pending arbitration proceeding.

GREAT PLAINS ENERGY AND CONSOLIDATED KCP&L SIGNIFICANT BALANCE SHEET CHANGES (December 31, 2004 compared to December 31, 2003)

- Great Plains Energy's restricted cash and supplier collateral decreased $13.2 million due to a reduction in the collateral provided from suppliers to cover portions of credit exposure as a result of lower market exposure with counterparties posting cash and one counterparty posting a letter of credit rather than cash.
- Great Plains Energy's receivables increased $6.8 million primarily due to a $35.0 million increase in Strategic Energy's receivables, which was primarily the result of increased sales in late 2004 compared to late 2003. This increase was mostly offset by a $32.3 million decrease in consolidated KCP&L's receivables. Consolidated KCP&L's receivables decreased primarily due to KCP&L's receipt of $30.8 million for the Hawthorn No. 5 insurance recovery.
- Great Plains Energy's and consolidated KCP&L's deferred income taxes (current assets) increased $12.4 million and $12.1 million, respectively, to reflect previously non-current deferred income taxes expected to reverse in 2005 and $4.4 million related to the timing of the Wolf Creek refueling outage.
- Great Plains Energy's assets of discontinued operations decreased $27.1 million due to the sale of KLT Gas' assets in 2004.
- Great Plains Energy's goodwill increased $60.7 million due to the purchase of the additional indirect interest in Strategic Energy in May 2004.
- Great Plains Energy's other deferred charges increased $31.5 million primarily due to $36.1 million in intangible assets, net of amortization, recorded as a result of the purchase of the additional indirect interest in Strategic Energy in May 2004.
- Great Plains Energy's notes payable decreased $67.0 million due to the net repayments of short-term borrowings. Consolidated KCP&L's notes payable to Great Plains Energy decreased $22.0 million primarily due to HSS' repayment of an intercompany loan mostly related to the disposition of RSAE.
- Great Plains Energy's and consolidated KCP&L's current maturities of long-term debt increased $193.9 million and $195.5 million, respectively, to reflect KCP&L's $250 million of senior notes scheduled to mature in 2005, partially offset by the retirement of KCP&L's $54.5 million of medium-term notes in 2004.
- Great Plains Energy's and consolidated KCP&L's Environmental Improvement Revenue Refunding (EIRR) bonds classified as current decreased $43.4 million due to scheduled remarketings of EIRR bonds. The new terms changed the classification of certain EIRR bonds to long-term debt.
- Great Plains Energy's other deferred credits and liabilities increased $9.4 million primarily due to an $18.8 million liability for the fair value of acquired retail contracts, net of amortization, partially offset by a $9.0 million reduction in minority interest recorded as a result of the purchase of an additional indirect interest in Strategic Energy in May 2004. An additional increase of $6.7 million was due to recording the FELINE PRIDES℠ long-term forward contract fee, partially offset by a $5.3 million decrease in consolidated KCP&L's other deferred credits and liabilities. Consolidated KCP&L's decrease was primarily due to a $4.6 million decrease in minority interest, which was the result of losses at KCP&L's Lease Trust.
- Great Plains Energy's common stock increased $154.1 million due to the issuance of five million shares of common stock in June 2004 and the issuance of shares for purchases under the Dividend Reinvestment and Direct Stock Purchase Plan plans. Consolidated KCP&L's common stock increased $225.0 million due to equity contributions from Great Plains Energy.

- Great Plains Energy's capital stock premium and expense increased $24.9 million primarily due to recording $19.6 million of FELINE PRIDES purchase contract adjustment, allocated fees and expenses. Additionally, the June 2004 common stock issuance costs totaled $5.4 million.
- Great Plains Energy's and consolidated KCP&L's long-term debt decreased $201.9 million and $362.3 million, respectively, to reflect KCP&L's $250 million of senior notes scheduled to mature in 2005 as current and the 2004 redemption of KCP&L's $154.6 million 8.3% Junior Subordinated Deferred Interest Bonds partially offset by KCP&L's EIRR bonds totaling $43.4 million now classified as long-term following the scheduled remarketing during 2004. Great Plains Energy's decrease was further offset by the issuance of $163.6 million of FELINE PRIDES senior notes in 2004.

CAPITAL REQUIREMENTS AND LIQUIDITY

Great Plains Energy operates through its subsidiaries and has no material assets other than the stock of its subsidiaries. Great Plains Energy's ability to make payments on its debt securities and its ability to pay dividends is dependent on its receipt of dividends or other distributions from its subsidiaries and proceeds from the issuance of its securities.

Great Plains Energy's capital requirements are principally comprised of KCP&L's utility construction and other capital expenditures, debt maturities, pension benefit plan funding requirements discussed below and credit support provided to Strategic Energy. Additional cash and capital requirements for the companies are discussed below.

Great Plains Energy's liquid resources at December 31, 2004, consisted of $127.1 million of cash and cash equivalents on hand, including $51.6 million at KCP&L, and $795.8 million of unused bank lines of credit. The unused lines consisted of $250.0 million from KCP&L's revolving credit facility, $55.8 million from Strategic Energy's revolving credit facility, and $490.0 million from Great Plains Energy's revolving credit facility. See the Debt Agreements section below for more information on these agreements.

Cash Flows From Operations

Great Plains Energy and consolidated KCP&L generated positive cash flows from operating activities for the periods presented. The increase in cash flows from operating activities for Great Plains Energy in 2004 compared to 2003 was primarily due to the changes in working capital detailed in Significant Balance Sheet Changes and in Note 2 to the consolidated financial statements. The individual components of working capital vary with normal business cycles and operations. In addition, the timing of the Wolf Creek outage affects the refueling outage accrual, deferred income taxes and amortization of nuclear fuel. Consolidated KCP&L's cash flow from operations increased in 2004 compared to 2003 partially due to a $17.4 million increase in income from continuing operations and the changes in working capital detailed in Significant Balance Sheet Changes and in Note 2 to the consolidated financial statements.

The increase in cash flows from operating activities for Great Plains Energy in 2003 compared to 2002 is primarily due to a $56.0 million increase in income from continuing operations and the changes in working capital detailed in Significant Balance Sheet Changes and in Note 2 to the consolidated financial statements. Consolidated KCP&L's cash flow from operations increased slightly in 2003 compared to 2002 due to a $26.2 million increase in income from continuing operations and an increase in deferred taxes mostly offset by the changes in working capital detailed in Significant Balance Sheet Changes and in Note 2 to the consolidated financial statements.

Investing Activities

Great Plains Energy's and consolidated KCP&L's cash used for investing activities varies with the timing of utility capital expenditures and purchases of investments and nonutility property. Investing activities are offset by the proceeds from the sale of properties and insurance recoveries. Great Plains Energy's and consolidated KCP&L's utility capital expenditures increased $41.9 million in 2004 compared to 2003 primarily due to the $28.5 million buyout of KCP&L's operating lease for vehicles and heavy equipment in 2004. Insurance recoveries and litigation settlements related to Hawthorn No. 5 in 2004 of $31.9 million, a $10.7 million increase over 2003 recoveries, offset cash used in investing activities. Additionally, Great Plains Energy paid $90.0 million to acquire an additional indirect interest in Strategic Energy during 2004.

Utility capital expenditures and the allowance for borrowed funds used during construction increased $17.9 million in 2003 compared to 2002 primarily due to transmission plant and nuclear fuel additions partially offset by 2002 capital expenditures of $14.7 million related to the January 2002 ice storm and insurance proceeds and partial litigation settlements from Hawthorn No. 5 received in 2003. In 2003, Great Plains Energy received proceeds of $19.2 million as a result of the DTI bankruptcy.

Financing Activities

The change in Great Plains Energy's cash flows from financing activities in 2004 compared to 2003 reflects Great Plains Energy's June 2004 gross proceeds of $150.0 million from the issuance of five million shares of common stock at $30 per share and $163.6 million from the issuance of 6.5 million FELINE PRIDES. Fees related to these issuances were $10.2 million. Great Plains Energy used the proceeds to repay short-term borrowings and to make $225.0 million of equity contributions to KCP&L. In 2004, KCP&L redeemed $154.6 million of 8.3% Junior Subordinated Deferred Interest Bonds from KCPL Financing I. KCPL Financing I used those proceeds to redeem the $4.6 million common securities held by KCP&L and the $150.0 million of 8.3% Trust Preferred Securities. See Note 19 to the consolidated financial statements for additional information. KCP&L also redeemed $54.5 million of its medium-term notes at maturity during 2004.

The change in Great Plains Energy and consolidated KCP&L's cash flows from financing activities in 2003 compared to 2002 reflects the 2003 equity infusion of $100.0 million from Great Plains Energy to KCP&L and KCP&L's subsequent redemption of $104.0 million of medium-term notes. Great Plains Energy essentially funded the infusion with proceeds from its $151.8 million common stock offering in late 2002; however, prior to the infusion, Great Plains Energy used the offering proceeds to repay short-term borrowings in late 2002 and then re-borrowed in early 2003 to make the equity infusion into KCP&L at the time of redemption. An additional $20.0 million of KCP&L's medium-term notes were retired during 2003. The increase in dividends paid by Great Plains Energy is primarily attributable to the public offering of 6.9 million common shares in late 2002.

In November 2002, Great Plains Energy entered into an Agreement and Plan of Merger (Agreement) with Environmental Lighting Concepts, Inc. (ELC), the ELC shareholders and IEC, a wholly owned subsidiary of Great Plains Energy, to acquire ELC's 6% indirect interest in Strategic Energy. The ELC Shareholders received $15.1 million in merger consideration. As part of the merger consideration, on November 7, 2002, Great Plains Energy issued 387,596 additional shares of its common stock to the ELC Shareholders. The Agreement valued such shares at approximately $8 million. The remainder of the merger consideration was in short-term notes, which were paid in January 2003.

KCP&L expects to meet day-to-day operating requirements including interest payments, construction requirements (excluding new generating capacity and environmental compliance on existing generating units) and dividends to Great Plains Energy with internally generated funds. However, it might not be able to meet these requirements with internally generated funds because of the effect of inflation on operating expenses, the level of MWh sales, regulatory actions, compliance with future environmental regulations and the availability of generating units. The funds Great Plains Energy and consolidated KCP&L need to retire maturing debt will be provided from operations, the issuance of long and short-term debt and/or the issuance of equity or equity-linked instruments. In addition, the Company may issue debt, equity and/or equity-linked instruments to finance growth or take advantage of new opportunities.

Strategic Energy expects to meet day-to-day operating requirements including interest payments, credit support fees, capital expenditures and dividends to its indirect interest holders with internally generated funds. However, it might not be able to meet these requirements with internally generated funds because of the effect of inflation on operating expenses, the level of MWh sales, commodity-price volatility and the effects of counterparty non-performance.

Great Plains Energy filed a registration statement, which became effective in April 2004, for the issuance of an aggregate amount up to $500.0 million of any combination of senior debt securities, subordinated debt securities, trust preferred securities and related guarantees, common stock, warrants, stock purchase contracts or stock purchase units. The prospectus filed with this registration statement also included $148.2 million of securities remaining available to be offered under a prior registration statement providing for an aggregate amount of availability of $648.2 million. In June 2004, Great Plains Energy issued $150.0 million of common stock and $163.6 million of FELINE PRIDES. After these issuances, $171.0 million remains available under this registration statement, which reflects the effect of the $163.6 million stock purchase contract component of FELINE PRIDES.

As a registered public utility holding company, Great Plains Energy must receive authorization from the SEC under the 35 Act to issue securities. Great Plains Energy is currently authorized to issue up to $1.2 billion of debt and equity through December 31, 2005. The following table reflects Great Plains Energy's utilization of this amount.

December 31	2004
	(millions)
Preferred stock issued in connection with the October 2001 reorganization	$ 39.0
Five-year credit facility [(a)]	28.0
November 2002 common equity offer	151.8
Common equity issued in connection with IEC's 2002 acquisition of an indirect ownership interest in Strategic Energy	8.0
June 2004 common equity offer	150.0
June 2004 FELINE PRIDES	163.6
June 2004 FELINE PRIDES purchase contracts	163.6
Issuance of common stock under the Dividend Reinvestment and Direct Stock Purchase Plan	3.7
Issuance of restricted stock to executives	2.3
Total utilized	$ 710.0

[(a)] This is a $550 million facility; however, at December 31, 2004, the Company could borrow a maximum of $518 million under the 35 Act authorization of which $28 million was outstanding at December 31, 2004.

Under its current SEC authorization, Great Plains Energy cannot issue securities other than common stock unless (i) the security to be issued, if rated, is rated investment grade by one nationally recognized statistical rating organization, (ii) all of its outstanding securities that are rated (except for its preferred stock) are rated investment grade by one nationally recognized statistical rating organization, and (iii) it has maintained common equity as a percentage of consolidated capitalization (as reflected on its consolidated balance sheets as of the end of each quarter) of at least 30%. Great Plains Energy was in compliance with these conditions as of December 31, 2004.

In 2003, KCP&L filed a shelf registration statement for up to $255 million of senior and subordinated debt securities, trust preferred securities and related guarantees providing KCP&L flexibility to access the capital markets.

KCP&L may issue equity and long-term debt only with the authorization of the MPSC. In June 2004, the MPSC authorized KCP&L to issue up to $600 million of long-term debt through March 31, 2006. The authorization contains the following conditions, among others: (i) no more than $150.0 million of the authorized debt can be used for purposes other than refinancing existing securities and (ii) the proceeds of the authorized debt must be used exclusively for the benefit of KCP&L's regulated operations.

Issuances of short-term debt by KCP&L are subject to SEC authorization under the 35 Act. Under the current authorization, KCP&L may issue and have outstanding at any given time up to $500 million of short-term debt. Under this authorization, KCP&L cannot issue short-term debt (other than commercial paper or short-term bank facilities) unless (i) the short-term debt to be issued, if rated, is rated investment grade by one nationally recognized statistical rating organization, (ii) all of its outstanding securities that are rated are rated investment grade by one nationally recognized statistical rating organization, (iii) all of the outstanding rated securities of Great Plains Energy (except preferred stock) are rated investment grade and (iv) Great Plains Energy and KCP&L have maintained common equity as a percentage of consolidated capitalization (as reflected on their consolidated balance sheets as of the end of each quarter) of at least 30%. KCP&L was in compliance with these conditions as of December 31, 2004.

In 2004, KCP&L remarketed its secured 1994 series EIRR bonds totaling $35.9 million and its unsecured 1998 Series C EIRR bonds totaling $50.0 million. The bonds are classified as current liabilities in the December 31, 2004, balance sheet. The 1994 series bonds were remarketed with a one-year maturity at a fixed interest rate of 2.25%. The 1998 Series C bonds were remarketed with a one-year maturity at a fixed interest rate of 2.38%. KCP&L also remarketed its secured 1993 series EIRR bonds totaling $12.4 million at a fixed rate of 4.0% until maturity at January 2, 2012.

In 2004, KCP&L secured a municipal bond insurance policy as a credit enhancement to its secured 1992 series EIRR bonds totaling $31.0 million. This municipal bond insurance policy replaced a 364-day credit facility with a bank, which expired in August 2004 that previously supported full liquidity of these bonds. These variable-rate secured EIRR bonds with a final maturity in 2017 are remarketed on a weekly basis through a Dutch auction process.

KCP&L had entered into a revolving agreement to sell all of its right, title and interest in the majority of its customer accounts receivable to Kansas City Power & Light Receivables Company, which in turn sold most of the receivables to outside investors. The agreement expired in January 2005 and was not renewed by KCP&L. KCP&L is currently evaluating alternatives to replace this agreement and intends to enter into a new agreement in 2005. See Note 3 to the consolidated financial statements.

Debt Agreements

In December 2004, Great Plains Energy syndicated a $550 million, five-year revolving credit facility with a group of banks replacing a $150.0 million 364-day revolving credit facility and a $150.0 million three-year revolving credit facility with a group of banks that were syndicated earlier in 2004. Those latter two facilities had replaced a prior $225.0 million revolving credit facility with a group of banks. The new facility contains a Material Adverse Change (MAC) clause that requires Great Plains Energy to represent, prior to receiving funding, that no MAC has occurred. The clause does, however, permit the Company to access the facility even in the event of a MAC in order to repay maturing commercial paper. Available liquidity under this facility is not impacted by a decline in credit ratings unless the downgrade results in a MAC or occurs in the context of a merger, consolidation or sale. A default by

Great Plains Energy or any of its significant subsidiaries of other indebtedness totaling more than $25.0 million is a default under the current facility. Under the terms of this agreement, Great Plains Energy is required to maintain a consolidated indebtedness to consolidated capitalization ratio, as defined in the agreement, not greater than 0.65 to 1.00 at all times. At December 31, 2004, the Company was in compliance with this covenant. At December 31, 2004, Great Plains Energy had $20.0 million of outstanding borrowings with an interest rate of 3.04% and had issued letters of credit totaling $8.0 million under the credit facility as credit support for Strategic Energy. At December 31, 2004, Great Plains Energy had $490 million available under this facility due to limitations under its 35 Act authorization.

In December 2004, KCP&L syndicated a $250 million five-year revolving credit facility. This facility replaced $155 million in 364-day bilateral credit lines KCP&L had in place with a group of banks. KCP&L uses this facility to provide support for its issuance of commercial paper and other general purposes. The new facility contains a MAC clause that requires KCP&L to represent, prior to receiving funding, that no MAC has occurred. The clause does, however, permit KCP&L to access the facility even in the event of a MAC in order to repay maturing commercial paper. Available liquidity under this facility is not impacted by a decline in credit ratings unless the downgrade results in a MAC or occurs in the context of a merger, consolidation or sale. A default by KCP&L on other indebtedness totaling more than $25.0 million is a default under the current facility. Under the terms of the agreement, KCP&L is required to maintain a consolidated indebtedness to consolidated capitalization ratio, as defined in the agreement, not greater than 0.65 to 1.00 at all times. At December 31, 2004, KCP&L was in compliance with this covenant. At December 31, 2004, KCP&L had no short-term borrowings outstanding.

During 2004, Strategic Energy syndicated a $125.0 million three-year revolving credit facility with a group of banks. Great Plains Energy has guaranteed $25.0 million of this facility. This facility replaced a $95.0 million revolving credit facility with a group of banks. The existing facility contains a MAC clause that requires Strategic Energy to represent, prior to receiving funding, that no MAC has occurred. A default by Strategic Energy of other indebtedness, as defined in the facility, totaling more than $7.5 million is a default under the facility. Under the terms of this agreement, Strategic Energy is required to maintain a minimum net worth of $62.5 million, a maximum funded indebtedness to EBITDA ratio of 2.25 to 1.00, a minimum fixed charge coverage ratio of at least 1.05 to 1.00 and a minimum debt service coverage ratio of at least 4.00 to 1.00, as those terms are defined in the agreement. In the event of a breach of one or more of these four covenants, so long as no other default has occurred, Great Plains Energy may cure the breach through a cash infusion, a guarantee increase or a combination of the two. At December 31, 2004, Strategic Energy was in compliance with these covenants. At December 31, 2004, $69.2 million in letters of credit had been issued and there were no borrowings under the agreement, leaving $55.8 million of capacity available for loans and additional letters of credit.

Great Plains Energy has agreements with KLT Investments associated with notes KLT Investments issued to acquire its affordable housing investments. Great Plains Energy has agreed not to take certain actions including, but not limited to, merging, dissolving or causing the dissolution of KLT Investments, or withdrawing amounts from KLT Investments if the withdrawals would result in KLT Investments not being in compliance with minimum net worth and cash balance requirements. The agreements also give KLT Investments' lenders the right to have KLT Investments repurchase the notes if Great Plains Energy's senior debt rating falls below investment grade or if Great Plains Energy ceases to own at least 80% of KCP&L's stock. At December 31, 2004, KLT Investments had $5.8 million in outstanding notes, including current maturities.

Under stipulations with the MPSC and the KCC, Great Plains Energy and KCP&L maintain common equity at not less than 30% and 35%, respectively, of total capitalization. Pursuant to an SEC order, Great Plains Energy's and KCP&L's authorization to issue securities is conditioned on maintaining a consolidated common equity capitalization of at least 30% and complying with other conditions described above.

KCP&L Projected Utility Capital Expenditures

Total utility capital expenditures, excluding allowance for funds used to finance construction, were $190.5 million, $148.7 million and $132.0 million in 2004, 2003 and 2002, respectively. Utility capital expenditures projected for the next three years are in the following table.

	2005	2006	2007
		(millions)	
Generating facilities	$ 43.4	$ 61.3	$ 47.7
Nuclear fuel	4.6	18.6	23.7
Distribution and transmission facilities	69.1	76.5	90.4
General facilities	18.2	17.7	13.6
Total	$ 135.3	$ 174.1	$ 175.4

This utility capital expenditure plan is subject to continual review and change and does not reflect utility capital expenditures for new capacity. These projections could be significantly impacted by KCP&L's comprehensive energy plan for environmental investments and new generation, which has the potential to add approximately $1.1 billion in capital investment for KCP&L over the next five years. See Strategic Intent for additional information.

Pensions

The Company maintains defined benefit plans for substantially all employees of KCP&L, Services and WCNOC and incurs significant costs in providing the plans, with the majority incurred by KCP&L. At a minimum, plans are funded on an actuarial basis to provide assets sufficient to meet benefits to be paid to plan participants consistent with the funding requirements of the Employee Retirement Income Security Act of 1974 (ERISA) and further contributions may be made when deemed financially advantageous.

The Company contributed $39.1 million to the plans in 2004, which included $35.0 million of additional funding above the minimum ERISA funding requirements. In 2003, the Company contributed $41.2 million to the plans, which included $26.8 million to cover the 2003 and a portion of the 2004 minimum funding requirements. KCP&L contributed $32.7 million and $39.3 million of the contributions in 2004 and 2003, respectively.

The ERISA funding requirement for 2005 is projected to be $4.7 million, all of which will be paid by KCP&L. Management believes the Company has adequate access to capital resources through cash flows from operations or through existing lines of credit to support the funding requirement. Participants in the plans may request a lump-sum cash payment upon termination of their employment. A change in payment assumptions could result in increased cash requirements from pension plan assets with the Company being required to accelerate future funding.

Under the terms of the pension plans, the Company reserves the right to amend or terminate the plans, and from time to time benefits have changed. See Note 9 to the consolidated financial statements for additional information.

Credit Ratings

At December 31, 2004, the major credit rating agencies rated the companies' securities as detailed in the following table.

	Moody's Investors Service	Standard and Poor's
Great Plains Energy		
Outlook	Negative	Stable
Corporate Credit Rating	-	BBB
Preferred Stock	Ba1	BB+
Senior Unsecured Debt	Baa2	BBB-
KCP&L		
Outlook	Stable	Stable
Senior Secured Debt	A2	BBB
Senior Unsecured Debt	A3	BBB
Commercial Paper	P-2	A-2

The ratings presented reflect the current views of these rating agencies and are subject to change. The companies view maintenance of strong credit ratings as being extremely important and to that end an active and ongoing dialogue is maintained with the agencies with respect to the companies' results of operations, financial position, and future prospects.

None of the companies' outstanding debt, except for the notes associated with affordable housing investments, requires the acceleration of interest and/or principal payments in the event of a ratings downgrade, unless the downgrade occurs in the context of a merger, consolidation, or sale. In the event of a downgrade the companies and/or their subsidiaries may be subject to increased interest costs on their credit facilities. Additionally, in KCP&L's bond insurance policies on its secured 1992 series EIRR bonds totaling $31.0 million and its Series 1993A and 1993B EIRR bonds totaling $79.5 million, KCP&L has agreed to limits on its ability to issue additional mortgage bonds based on the mortgage bond's credit ratings. See Note 19 to the consolidated financial statements.

Supplemental Capital Requirements and Liquidity Information

The information in the following tables is provided to summarize cash obligations and commercial commitments.

Great Plains Energy Contractual Obligations

Payment due by period	2005	2006	2007	2008	2009	After 2009	Total
Long-term debt				(millions)			
Principal	$ 253.2	$ 147.0	$ 389.6	$ 0.3	$ -	$ 505.3	$ 1,295.4
Interest	70.5	53.9	25.9	21.3	21.2	101.9	294.7
Lease obligations	21.4	21.7	13.4	11.1	8.7	85.2	161.5
Pension plans	4.7	-	-	-	-	-	4.7
Purchase obligations							
Fuel	74.2	80.7	63.7	30.9	7.3	43.2	300.0
Purchased capacity	10.9	5.4	5.5	5.6	4.4	24.8	56.6
Purchased power	697.2	201.5	65.6	10.3	3.7	3.7	982.0
Other	32.9	5.2	4.0	4.7	-	-	46.8
Total contractual obligations	$ 1,165.0	$ 515.4	$ 567.7	$ 84.2	$ 45.3	$ 764.1	$ 3,141.7

Consolidated KCP&L Contractual Obligations

Payment due by period	2005	2006	2007	2008	2009	After 2009	Total
Long-term debt				(millions)			
Principal	$ 250.0	$ 145.2	$ 225.5	$ -	$ -	$ 505.3	$ 1,126.0
Interest	57.1	40.6	24.0	21.2	21.2	101.9	266.0
Lease obligations	20.1	20.5	12.4	10.3	8.7	85.2	157.2
Pension plans	4.7	-	-	-	-	-	4.7
Purchase obligations							
Fuel	74.2	80.7	63.7	30.9	7.3	43.2	300.0
Purchased capacity	10.9	5.4	5.5	5.6	4.4	24.8	56.6
Other	32.9	5.2	4.0	4.7	-	-	46.8
Total contractual obligations	$ 449.9	$ 297.6	$ 335.1	$ 72.7	$ 41.6	$ 760.4	$ 1,957.3

Long-term debt includes current maturities. Long-term debt principal excludes $0.5 million discount on senior notes and the $0.7 million fair value adjustment to the EIRR bonds related to SFAS No. 133. EIRR bonds classified as current liabilities of $85.9 million due at various dates during the years 2015 through 2018 are included here on their final maturity date. Variable rate interest obligations are based on rates as of January 1, 2005. See Note 19 to the consolidated financial statements for additional information.

Lease obligations include capital and operating lease obligations; capital lease obligations are $0.2 million per year for the years 2005 through 2009 and total $4.1 million after 2009. Lease obligations also include leases for railcars to serve jointly-owned generating units where KCP&L is the managing partner. KCP&L will be reimbursed by the other owners for about $2.0 million per year ($21.9 million total) of the amounts included in the table above. See Note 13, contractual commitments, to the consolidated financial statements for additional information regarding leases.

Pension plans represent only the minimum funding requirements under ERISA. Minimum funding requirements for future periods are not yet known. The Company's 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 9 to the consolidated financial statements for additional information regarding pensions.

Fuel represents KCP&L's 47% share of Wolf Creek nuclear fuel commitments, KCP&L's share of coal purchase commitments based on estimated prices to supply coal for generating plants and KCP&L's share of rail transportation commitments for moving coal to KCP&L's generating units.

KCP&L purchases capacity from other utilities and nonutility suppliers. Purchasing capacity provides the option to purchase energy if needed or when market prices are favorable. This can be a cost-effective alternative to new construction. KCP&L has capacity sales agreements not included above that total $11.7 million for 2005, $11.4 million for 2006, $11.2 million per year for 2007 through 2009 and $23.5 million after 2009.

Purchased power represents Strategic Energy's agreements to purchase electricity at various fixed prices to meet estimated supply requirements. Strategic Energy has energy sales contracts not included above for 2005 through 2007 totaling $69.1 million, $8.7 million and $0.6 million, respectively.

Other purchase obligations represent individual commitments entered into in the ordinary course of business.

Great Plains Energy and consolidated KCP&L have long-term liabilities recorded on their consolidated balance sheets at December 31, 2004, under GAAP that do not have a definitive cash payout date and are not included in the table above.

Off-Balance Sheet Arrangements

In the normal course of business, Great Plains Energy and certain of its subsidiaries enter into various agreements providing financial or performance assurance to third parties on behalf of certain subsidiaries. Such agreements include, for example, guarantees, stand-by letters of credit and surety bonds. These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to a subsidiary on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended business purposes.

As a registered public utility holding company system, Great Plains Energy must receive authorization from the SEC, under the 35 Act, to issue guarantees on behalf of its subsidiaries. Under its current SEC authorization, guarantees cannot be issued unless (i) all of its outstanding securities that are rated (except for its preferred stock) are rated investment grade and (ii) it has maintained common equity as a percentage of consolidated capitalization (as reflected on its consolidated balance sheets as of the end of each quarter) of at least 30%. Great Plains Energy was in compliance with these conditions as of December 31, 2004. Great Plains Energy is currently authorized to issue up to $600 million of guarantees on behalf of its subsidiaries and the nonutility subsidiaries have $300 million of authorization for guarantees they can issue on behalf of other nonutility subsidiaries. The nonutility subsidiaries cannot issue guarantees unless Great Plains Energy is in compliance with its conditions to issue guarantees.

Other Commercial Commitments Outstanding

	Amount of commitment expiration per period						
	2005	**2006**	**2007**	**2008**	**2009**	**After 2009**	**Total**
				(millions)			
Consolidated KCP&L Guarantees	$ 1.4	$ 1.0	$ 1.0	$ 1.0	$ 1.0	$ 1.0	$ 6.4
Great Plains Energy Guarantees, including consolidated KCP&L	$ 117.6	$ 1.0	$ 1.0	$ 1.0	$ 1.0	$ 1.1	$ 122.7

KCP&L is contingently liable for guaranteed energy savings under agreements with several customers. KCP&L has entered agreements guaranteeing an aggregate value of approximately $6.4 million over the next six years. In most cases, a subcontractor would indemnify KCP&L for any payments made by KCP&L under these guarantees.

Great Plains Energy and KLT Inc. have provided $116.3 million of guarantees to support certain Strategic Energy power purchases and regulatory requirements. At December 31, 2004, guarantees related to Strategic Energy are as follows:

- Great Plains Energy direct guarantees to counterparties totaling $53.3 million and KLT Inc. direct guarantees to counterparties totaling $0.1 million, with varying expiration dates,
- Great Plains Energy provides indemnifications to the issuers of surety bonds totaling $29.9 million which expire in 2005,
- Great Plains Energy guarantees related to letters of credit totaling $25.0 million, which expire in 2005 and 2006 and
- Great Plains Energy letters of credit totaling $8.0 million.

The table above does not include guarantees related to bond insurance policies that KCP&L has as a credit enhancement to its secured 1992 series EIRR bonds totaling $31.0 million and its Series 1993A and 1993B EIRR bonds totaling $79.5 million. The insurance agreement between KCP&L and the issuer of the bond insurance policies provides for reimbursement by KCP&L for any amounts the insurer pays under the bond insurance policies.

RISK FACTORS

Actual results in future periods for Great Plains Energy and consolidated KCP&L could differ materially from historical results and the forward-looking statements contained in this report. Factors that might cause or contribute to such differences include, but are not limited to, those discussed below. These and many other factors described in this report, including the factors listed in the "Cautionary Statements Regarding Certain Forward-Looking Information" and "Quantitative and Qualitative Disclosures About Market Risks" sections of this report, could adversely affect the results of operations and financial position of Great Plains Energy and consolidated KCP&L. Risk factors of consolidated KCP&L are also risk factors for Great Plains Energy.

KCP&L Has Operations Risks

The operation of KCP&L's electric generation, transmission and distribution systems involves many risks, including breakdown or failure of equipment or processes; operating limitations that may be imposed by equipment conditions, environmental or other regulatory requirements; fuel supply or fuel transportation reductions or interruptions; and catastrophic events such as fires, explosions, severe weather or other similar occurrences. These events may reduce revenues or increase costs, or both, at KCP&L, and may materially affect KCP&L's results of operations and financial position.

KCP&L And Strategic Energy Are Affected By Demand, Seasonality And Weather

The results of operations of KCP&L and Strategic Energy can be materially affected by changes in weather and customer demand. KCP&L and Strategic Energy estimate customer demand based on historical trends, to procure fuel and purchased power. Differences in customer usage from these estimates due to weather or other factors could materially affect KCP&L's and Strategic Energy's results of operations.

Weather conditions directly influence the demand for electricity and natural gas and affect the price of energy commodities. KCP&L is significantly impacted by seasonality with approximately one-third of its retail revenues recorded in the third quarter. Strategic Energy is impacted by seasonality, but to a much lesser extent. In addition, severe weather, including but not limited to tornados, snow, rain and ice storms can be destructive causing outages and property damage that can potentially result in additional expenses and lower revenues. KCP&L's Iatan and Hawthorn power plants use water from the Missouri River for cooling purposes. A continuing drought in the north central United States has led to record low river levels in the Missouri River reservoir system, resulting in lower water and flow levels in the Missouri River. Low water and flow levels can increase KCP&L's maintenance costs and, if these levels are low enough, could cause KCP&L to modify plant operations.

KCP&L Has Nuclear Exposure

KCP&L owns 47% (548 MW) of Wolf Creek. The NRC has broad authority under Federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities, including Wolf Creek. In the event of non-compliance, the NRC has the authority to impose fines, shutdown the facilities, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. Any revised safety requirements promulgated by the NRC could result in substantial capital expenditures at Wolf Creek.

Wolf Creek has the lowest fuel cost per MWh of any of KCP&L's generating units. Although not expected, an extended shut-down of Wolf Creek, whether resulting from NRC action, an incident at the plant or otherwise, could have a substantial adverse effect on KCP&L's results of operations and financial position in the event KCP&L incurs higher replacement power and other costs that are not recovered through rates. If a long-term shut down occurred, the state regulatory commissions could reduce rates by excluding the Wolf Creek investment from rate base.

Ownership and operation of a nuclear generating unit exposes KCP&L to risks regarding decommissioning costs at the end of the unit's life. KCP&L contributes annually to a tax-qualified trust fund to be used to decommission Wolf Creek. The funding level assumes a projected level of return on trust assets. If the actual return on trust assets is below the anticipated level, KCP&L could be responsible for the balance of funds required. If returns are lower than the expected level, KCP&L believes a rate increase would be allowed ensuring full recovery of decommissioning costs over the remaining life of the unit.

KCP&L is also exposed to other risks associated with the ownership and operation of a nuclear generating unit, including but not limited to potential liability associated with the potential harmful effects on the environment and human health resulting from the operation of a nuclear generating unit and the storage, handling and disposal of radioactive materials, and to potential retrospective assessments and losses in excess of insurance coverage.

The Company Is Subject to Environmental Laws and the Incurrence of Environmental Liabilities
The Company is subject to regulation by federal, state and local authorities with regard to air and other environmental matters primarily through KCP&L's operations. The generation, transmission and distribution of electricity produces and requires disposal of certain hazardous products, which are subject to these laws and regulations. In addition to imposing continuing compliance obligations, these laws and regulations authorize the imposition of substantial penalties for noncompliance, including fines, injunctive relief and other sanctions. Failure to comply with these laws and regulations could have a material adverse effect on Great Plains Energy and consolidated KCP&L results of operations and financial position. KCP&L regularly conducts environmental audits designed to ensure compliance with governmental regulations and to detect contamination.

New environmental laws and regulations affecting KCP&L's operations may be adopted, and new interpretations of existing laws and regulations could be adopted or become applicable to KCP&L or its facilities, which may substantially increase its environmental expenditures in the future. New facilities, or modifications of existing facilities, may require new environmental permits or amendments to existing permits. Delays in the environmental permitting process, denials of permit applications or conditions imposed in permits may materially affect KCP&L's results of operations and financial position. In addition, KCP&L may not be able to recover all of its costs for environmental expenditures through rates at current levels in the future. Under current law, KCP&L is also generally responsible for any on-site liabilities associated with the environmental condition of its facilities that it has previously owned or operated, regardless of whether the liabilities arose before, during or after the time it owned or operated the facilities. The incurrence of material environmental costs or liabilities, without related rate recovery, could have a material adverse effect on KCP&L's results of operations and financial position. See Note 13 to the consolidated financial statements for additional information regarding environmental matters.

KCP&L and Strategic Energy Have Commodity Price Risks
KCP&L and Strategic Energy engage in the wholesale and retail marketing of electricity and, accordingly, are exposed to risks associated with the price of electricity. Strategic Energy routinely enters into contracts to purchase and sell electricity in the normal course of business. KCP&L generates, purchases and sells electricity in the retail and wholesale markets.

Fossil Fuel and Transportation Prices Impact KCP&L's Costs

The majority of KCP&L's rates do not contain an automatic fuel adjustment provision, exposing KCP&L to risk from changes in the market prices of coal and natural gas used to generate power and in the cost of coal and natural gas transportation. Changes in KCP&L's fuel mix due to electricity demand, plant availability, transportation issues, fuel prices and other factors can also adversely affect KCP&L's fuel costs. KCP&L's net income may be adversely affected until increased costs are recovered in rates.

KCP&L manages its exposure to coal and coal rail transportation prices through the structure of commercial contracts. KCP&L enters into coal purchase contracts with various suppliers in Wyoming's Powder River Basin to hedge significant portions of its projected coal requirements for upcoming years consistent with KCP&L risk management policies. The remainder of KCP&L's coal requirements are generally insignificant and are fulfilled through additional contracts or spot market purchases. About half of KCP&L's delivered cost of coal is for rail transportation. KCP&L enters into rail transportation contracts to reduce the degree of variability in the delivered cost of coal. Coal rail transportation prices are generally trending upwards, primarily due to rail transportation companies moving away from contract rates to tariff rates, which could impact KCP&L as it renegotiates rail contracts expiring at the end of 2005. KCP&L also hedges its expected natural gas usage for retail load and firm MWh sales consistent with its risk management policies.

KCP&L does not hedge its entire exposure from fossil fuel and transportation price volatility. As a consequence, its results of operations and financial position may be materially impacted by changes in these prices.

Wholesale Electricity Prices Affect Costs and Revenues

KCP&L's ability to maintain or increase its level of wholesale sales depends on the wholesale market price, transmission availability and the availability of KCP&L's generation for wholesale sales, among other factors. A substantial portion of KCP&L's wholesale sales are made in the spot market, and thus KCP&L has immediate exposure to wholesale price changes. Declines in wholesale market price or availability of generation or transmission constraints in the wholesale markets, could reduce KCP&L's wholesale sales and adversely affect KCP&L's results of operations and financial position.

KCP&L is also exposed to risk because at times it purchases power to meet its customers' needs. The cost of these purchases may be affected by the timing of customer demand and/or unavailability of KCP&L's lower-priced generating units. Wholesale power prices can be volatile and generally increase in times of high regional demand and high natural gas prices.

As described below, Strategic Energy operates in competitive retail electricity markets, competing against the host utilities and other retail suppliers. Wholesale electricity costs, which account for a significant portion of its operating expenses, can materially affect Strategic Energy's ability to attract and retain retail electricity customers at profitable prices. There is also a regulatory lag that slows the adjustment of host public utility rates in response to changes in wholesale prices. This lag can negatively affect Strategic Energy's ability to compete in a rising wholesale price environment, which is the current environment. Strategic Energy manages wholesale electricity risk by establishing risk limits and entering into contracts to offset some of its positions to balance energy supply and demand; however, Strategic Energy does not hedge its entire exposure to electricity price volatility. As a consequence, its results of operations and financial position may be materially impacted by changes in the wholesale price of electricity.

Strategic Energy Operates in Competitive Retail Electricity Markets

Strategic Energy has several competitors that operate in most or all of the same states in which Strategic Energy serves customers. Some of these competitors also operate in states other than where Strategic Energy has operations. It also faces competition in certain markets from regional suppliers and deregulated utility affiliates formed by holding companies affiliated with regulated utilities to provide retail load in their home market territories. Strategic Energy's competitors vary in size from small companies to large corporations, some of which have significantly greater financial, marketing and procurement resources than Strategic Energy. Additionally, Strategic Energy, as well as its other competitors, must compete with the host utility in order to convince customers to switch from the host utility. Strategic Energy's results of operations and financial position are impacted by the success Strategic Energy has in attracting and retaining customers in these markets.

Strategic Energy has Wholesale Electricity Supplier Concentration and Credit Risk
Credit risk represents the loss that Strategic Energy could incur if a counterparty failed to perform under its contractual obligations. To reduce its credit exposure, Strategic Energy enters into payment netting agreements with certain counterparties that permit Strategic Energy to offset receivables and payables with such counterparties. Strategic Energy further reduces credit risk with certain counterparties by entering into agreements that enable Strategic Energy to terminate the transaction or modify collateral thresholds upon the occurrence of credit-related events.

Based on guidelines set by Strategic Energy's Exposure Management Committee, counterparty credit risk is monitored by routinely evaluating the credit quality and performance of its suppliers. Among other things, Strategic Energy monitors counterparty credit ratings, liquidity and results of operations. As a result of these evaluations, Strategic Energy establishes counterparty credit limits and adjusts the amount of collateral required from its suppliers, among other measures.

Strategic Energy enters into forward contracts with multiple suppliers. At December 31, 2004, Strategic Energy's five largest suppliers under forward supply contracts represented 70% of the total future committed purchases. Four of Strategic Energy's five largest suppliers, or their guarantors, are rated investment grade and the non-investment grade rated supplier collateralizes its position with Strategic Energy. In the event of supplier non-delivery or default, Strategic Energy's results of operations could be affected to the extent the cost of replacement power exceeded the combination of the contracted price with the supplier and the amount of collateral held by Strategic Energy to mitigate its credit risk with the supplier. In addition to the collateral, if any, that the supplier provides, Strategic Energy's risk is further mitigated by the obligation of the supplier to make a default payment equal to the shortfall and to pay liquidated damages in the event of a failure to deliver power. Strategic Energy's results of operations could also be affected, in a given period, if it was required to make a payment upon termination of a supplier contract to the extent that the contracted price with the supplier exceeded the market value of the contract at the time of termination.

The following table provides information on Strategic Energy's credit exposure to suppliers, net of collateral, as of December 31, 2004. It further delineates the exposure by the credit rating of counterparties and provides guidance on the concentration of credit risk and an indication of the maturity of the credit risk by credit rating of the counterparties.

Rating	Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number Of Counterparties Greater Than 10% Of Net Exposure	Net Exposure Of Counterparties Greater Than 10% of Net Exposure
External rating		(millions)			(millions)
Investment Grade	$ 49.4	$ -	$ 49.4	2	$ 43.9
Non-Investment Grade	18.0	14.0	4.0	-	-
Internal rating					
Investment Grade	3.9	-	3.9	-	-
Non-Investment Grade	5.6	5.5	0.1	-	-
Total	$ 76.9	$ 19.5	$ 57.4	2	$ 43.9

Maturity Of Credit Risk Exposure Before Credit Collateral				
Rating	Less Than 2 Years	2 - 5 Years	Exposure Greater Than 5 Years	Total Exposure
External rating			(millions)	
Investment Grade	$ 46.1	$ 3.3	$ -	$ 49.4
Non-Investment Grade	13.5	3.8	0.7	18.0
Internal rating				
Investment Grade	3.8	0.1	-	3.9
Non-Investment Grade	4.2	1.1	0.3	5.6
Total	$ 67.6	$ 8.3	$ 1.0	$ 76.9

External ratings are determined by using publicly available credit ratings of the counterparty. If a counterparty has provided a guarantee by a higher rated entity, the determination has been based on the rating of its guarantor. Internal ratings are determined by, among other things, an analysis of the counterparty's financial statements and consideration of publicly available credit ratings of the counterparty's parent. Investment grade counterparties are those with a minimum senior unsecured debt rating of BBB- from Standard & Poor's or Baa3 from Moody's. Exposure before credit collateral has been calculated considering all netting agreements in place, netting accounts payable and receivable exposure with net mark-to-market exposure. Exposure before credit collateral, after consideration of all netting agreements, is impacted significantly by the power supply volume under contract with a given counterparty and the relationship between current market prices and contracted power supply prices. Credit collateral includes the amount of cash deposits and letters of credit received from counterparties. Net exposure has only been calculated for those counterparties to which Strategic Energy is exposed and excludes counterparties exposed to Strategic Energy.

At December 31, 2004, Strategic Energy had exposure before collateral to non-investment grade counterparties totaling $23.6 million, of which 75% is scheduled to mature in less than two years. In addition, Strategic Energy held collateral totaling $19.5 million limiting its exposure to these non-investment grade counterparties to $4.1 million.

Strategic Energy is continuing to pursue a strategy of contracting with national and regional counterparties that have direct supplies and assets in the region of demand. Strategic Energy is also continuing to manage its counterparty portfolio through strict margining, collateral requirements and contract based netting of credit exposures against payable balances.

Great Plains Energy's Ability to Pay Dividends and Meet Financial Obligations Depends on its Subsidiaries

Great Plains Energy is a holding company with no significant operations of its own. The primary source of funds for payment of dividends to its shareholders and its financial obligations is dividends paid to it by its subsidiaries. The ability of Great Plains Energy's subsidiaries to pay dividends or make other distributions, and, accordingly, Great Plains Energy's ability to pay dividends on its common stock and meet its financial obligations, will depend on the actual and projected earnings and cash flow, capital requirements and general financial position of its subsidiaries, as well as on regulatory factors, financial covenants, general business conditions and other matters.

The Company has Regulatory Risks

The Company is subject to extensive regulation under the 35 Act and Federal and state utility regulation, as described below. Failure to obtain in a timely manner adequate rates or regulatory approvals, adoption of new regulations by Federal or State agencies, or changes to current regulations and interpretations of such regulations may materially affect the Company's business and its results of operations and financial position.

The Company is a Registered Holding Company Under the 35 Act

Great Plains Energy and its subsidiaries comprise a registered holding company system under the 35 Act, and are subject to certain limitations and approval requirements with respect to matters such as the structure of the holding company system, payment of dividends out of capital, transactions among affiliates, acquisitions, business combinations, the issuance, sale and acquisition of securities and engaging in business activities not directly related to the utility or energy business.

KCP&L and Strategic Energy are Impacted by Federal and State Utility Regulation

KCP&L is also regulated by the MPSC and KCC with respect to retail rates, accounting matters, standards of service and, in certain cases, the issuance of securities and certification of facilities and service territories. Pursuant to a stipulation entered into in 2002, KCP&L has agreed to file a rate case with the KCC by May 15, 2006. KCP&L currently is engaged in discussions with interested participants, seeking an agreement on a proposed comprehensive energy plan relating to generation additions, environmental and infrastructure improvements, rate recovery and other matters. KCP&L is also subject to regulation by the FERC with respect to wholesale electricity sales and transmission matters and the NRC as to nuclear operations.

Strategic Energy is a participant in the wholesale electricity and transmission markets, and is subject to FERC regulation with respect to wholesale electricity sales. Additionally, Strategic Energy is subject to regulation by state regulatory agencies in states where it has retail customers. Each state has a public utility commission and rules related to retail choice. Each state's rules are distinct and may conflict. These rules do not restrict the amount Strategic Energy can charge for its services, but can have an impact on Strategic Energy's ability to provide retail electricity services in each state. Additionally, each state regulates the rates of the host public utility, and the timing and amount of changes in host public utility rates can materially affect Strategic Energy's results of operations and financial position.

The Company has Financial Market and Ratings Risks

The Company relies on access to both short-term money markets and longer-term capital markets as a significant source of liquidity for capital requirements not satisfied by cash flows from operations. KCP&L's capital requirements are expected to increase substantially over the next several years if its regulatory plan, which includes environmental and generation investments, is approved. The Company believes that it will maintain sufficient access to these financial markets based upon current credit ratings and market conditions. However, changes in market conditions or credit ratings could adversely affect the companies' ability to access financial markets and could materially affect their results of operations and financial position.

Great Plains Energy, KCP&L and certain of their securities are rated by Moody's and Standard & Poor's. These ratings impact the Company's cost of funds and Great Plains Energy's ability to provide credit support for its subsidiaries. Additionally, Great Plains Energy and KCP&L must maintain investment-grade ratings from at least one nationally recognized rating agency as a condition of their 35 Act authorization to issue securities.

The Company's Financial Statements Reflect the Application of Critical Accounting Policies
The application of the Company's critical accounting policies reflects complex judgments and estimates. These policies include industry-specific accounting applicable to regulated public utilities, accounting for pensions, long-lived assets, derivative instruments and goodwill. The adoption of new GAAP or changes to current accounting policies or interpretations of such policies may materially affect the Company's results of operations and financial position.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

In the normal course of business, Great Plains Energy and consolidated KCP&L face risks that are either non-financial or non-quantifiable. Such risks principally include business, legal, operations and credit risks and are not represented in the following analysis. See Item 7. Management's Discussion and Analysis for further discussion of the companies' risk factors.

Great Plains Energy and consolidated KCP&L are exposed to market risks associated with commodity price and supply, interest rates and equity prices. Management has established risk management policies and strategies to reduce the potentially adverse effects that the volatility of the markets may have on its operating results. During the normal course of business, under the direction and control of internal risk management committees, the companies' hedging strategies are reviewed to determine the hedging approach deemed appropriate based upon the circumstances of each situation. Derivative instruments are frequently utilized to execute risk management and hedging strategies. Derivative instruments are instruments, such as futures, forward contracts, swaps or options that derive their value from underlying assets, indices, reference rates or a combination of these factors. These derivative instruments include negotiated contracts, which are referred to as over-the-counter derivatives and instruments that are listed and traded on an exchange. The companies maintain commodity-price risk management strategies that use derivative instruments to minimize significant, unanticipated net income fluctuations caused by commodity price volatility.

Interest Rate Risk
Great Plains Energy manages interest expense and short and long-term liquidity through a combination of fixed rate and variable rate debt. Generally, the amount of each type of debt is managed through market issuance, but interest rate swap and cap agreements with highly rated financial institutions may be used to achieve the desired combination. Using outstanding balances and annualized interest rates as of December 31, 2004, a hypothetical 10% increase in the interest rates associated with variable rate debt would result in an increase of less than $1.0 million in interest expense for 2005. Additionally, interest rates impact the fair value of long-term debt. A change in interest rates would impact the Company to the extent it redeemed any of its outstanding long-term debt. Great Plains Energy's and consolidated KCP&L's book values of long-term debt were between 3% and 4% below fair values at December 31, 2004.

Commodity Risk
KCP&L and Strategic Energy engage in the wholesale and retail marketing of electricity and are exposed to risk associated with the price of electricity.

KCP&L's wholesale operations include the physical delivery and marketing of power obtained through its generation capacity and long, intermediate and short-term capacity or power purchase agreements. The agreements contain penalties for non-performance to limit KCP&L's energy price risk on the contracted energy. KCP&L also enters into additional power purchase agreements with the objective of obtaining the most economical energy to meet its physical delivery obligations to its customers. KCP&L is required to maintain a capacity margin of at least 12% of its peak summer demand. This net positive supply of capacity and energy is maintained through its generation assets and capacity and power purchase agreements to protect it from the potential operational failure of one of its owned or contracted power generating units. KCP&L continually evaluates the need for additional risk mitigation measures in order to minimize its financial exposure to, among other things, spikes in wholesale power prices during periods of high demand.

KCP&L's sales include the sales of electricity to its retail customers and bulk power sales of electricity in the wholesale market. KCP&L continually evaluates its system requirements, the availability of generating units, availability and cost of fuel supply, the availability and cost of purchased power and the requirements of other electric systems; therefore, the impact of the hypothetical amounts that follow could be significantly reduced depending on the system requirements and market prices at the time of the increases. A hypothetical 10% decrease in the market price of power could result in a $3.5 million decrease in operating income for 2005 related to wholesale sales of electricity and purchased power. In 2005, approximately 77% of KCP&L's net MWhs generated are expected to be coal fired. KCP&L currently has almost all of its coal requirements for 2005 under contract. A hypothetical 10% increase in the market price of coal could result in less than a $1.0 million increase in fuel expense for 2005. KCP&L has also implemented price risk mitigation measures to reduce its exposure to high natural gas prices. A hypothetical 10% increase in natural gas and oil market prices could result in an increase of less than $1.0 million in fuel expense for 2005. As of December 31, 2004, KCP&L had slightly under half of its 2005 projected natural gas usage for retail load and firm MWh sales hedged, which is less than the percentages for 2004 hedged as of December 31, 2003.

Strategic Energy maintains a commodity-price risk management strategy that uses forward physical energy purchases and derivative instruments to minimize significant, unanticipated net income fluctuations caused by commodity-price volatility. In certain markets where Strategic Energy operates, entering into forward fixed price contracts is cost prohibitive. Derivative instruments, primarily swaps, are used to limit the unfavorable effect that price increases will have on electricity purchases, effectively fixing the future purchase price of electricity for the applicable forecasted usage and protecting Strategic Energy from significant price volatility. A hypothetical 10% increase in the cost of purchased power could result in less than $1.0 million increase in purchased power expense for 2005.

The effectiveness of the companies' policies and procedures for managing risk exposure can never be completely estimated or fully assured. The Company could experience losses, which could have a material adverse effect on its results of operations or financial position, from unexpectedly large or rapid movements or disruptions in the energy markets, from regulatory-driven market rule changes and/or bankruptcy of customers or counterparties.

Equity Price Risk

KCP&L maintains trust funds, as required by the NRC, to fund certain costs of decommissioning its Wolf Creek nuclear power plant. KCP&L does not expect Wolf Creek decommissioning to start before 2025. As of December 31, 2004, these funds were invested primarily in domestic equity securities and fixed income securities and are reflected at fair value on KCP&L's balance sheets. The mix of securities is designed to provide returns to be used to fund decommissioning and to compensate for inflationary increases in decommissioning costs; however, the equity securities in the trusts are exposed to price fluctuations in equity markets and the value of fixed rate fixed income securities are exposed to changes in interest rates. Investment performance and asset allocation are periodically reviewed. A hypothetical increase in interest rates resulting in a hypothetical 10% decrease in the value of the fixed income securities would have resulted in a $4.2 million reduction in the value of the decommissioning trust funds at December 31, 2004. A hypothetical 10% decrease in equity prices would have resulted in a $3.9 million reduction in the fair value of the equity securities at December 31, 2004. KCP&L's exposure to equity price market risk associated with the decommissioning trust funds is in large part mitigated due to the fact that KCP&L is currently allowed to recover its decommissioning costs in its rates.

KLT Investments has affordable housing notes that require the greater of 15% of the outstanding note balances or the next annual installment to be held as cash, cash equivalents or marketable securities. A hypothetical 10% decrease in market prices of the securities held as collateral could result in a decrease of less than $1.0 million in pre-tax net income for 2005.

GREAT PLAINS ENERGY
Consolidated Statements of Income

Year Ended December 31	2004	2003	2002
Operating Revenues	(thousands, except per share amounts)		
Electric revenues - KCP&L	$ 1,090,067	$ 1,054,900	$ 1,009,868
Electric revenues - Strategic Energy	1,370,760	1,089,663	788,278
Other revenues	3,191	3,482	4,147
Total	2,464,018	2,148,045	1,802,293
Operating Expenses			
Fuel	179,362	160,327	159,666
Purchased power - KCP&L	52,533	53,163	46,214
Purchased power - Strategic Energy	1,247,522	968,967	685,370
Other	324,237	295,383	276,632
Maintenance	83,603	85,416	91,419
Depreciation and amortization	150,071	142,763	146,757
General taxes	102,756	98,461	97,146
(Gain) loss on property	5,133	(23,703)	(1,376)
Total	2,145,217	1,780,777	1,501,828
Operating income	318,801	367,268	300,465
Non-operating income	6,799	7,414	5,839
Non-operating expenses	(15,184)	(20,462)	(18,948)
Interest charges	(83,030)	(76,171)	(87,380)
Income from continuing operations before income taxes, minority interest in subsidiaries and loss from equity investments	227,386	278,049	199,976
Income taxes	(54,451)	(78,565)	(51,348)
Minority interest in subsidiaries	2,131	(7,764)	(10,753)
Loss from equity investments	(1,531)	(2,018)	(1,173)
Income from continuing operations	173,535	189,702	136,702
Discontinued operations, net of income taxes (Notes 6 and 7)	7,276	(44,779)	(7,514)
Cumulative effect of a change in accounting principle (Note 5)	-	-	(3,000)
Net income	180,811	144,923	126,188
Preferred stock dividend requirements	1,646	1,646	1,646
Earnings available for common stock	$ 179,165	$ 143,277	$ 124,542
Average number of common shares outstanding	72,028	69,206	62,623
Basic and diluted earnings (loss) per common share			
Continuing operations	$ 2.39	$ 2.72	$ 2.16
Discontinued operations	0.10	(0.65)	(0.12)
Cumulative effect	-	-	(0.05)
Basic and diluted earnings per common share	$ 2.49	$ 2.07	$ 1.99
Cash dividends per common share	$ 1.66	$ 1.66	$ 1.66

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

GREAT PLAINS ENERGY
Consolidated Balance Sheets

	December 31 2004	2003
ASSETS	(thousands)	
Current Assets		
Cash and cash equivalents	$ 127,129	$ 114,227
Restricted cash	7,700	20,850
Receivables, net	247,184	240,344
Fuel inventories, at average cost	21,121	22,543
Materials and supplies, at average cost	54,432	56,599
Deferred income taxes	13,065	686
Assets of discontinued operations	749	27,830
Other	20,857	14,293
Total	492,237	497,372
Nonutility Property and Investments		
Affordable housing limited partnerships	41,317	52,644
Nuclear decommissioning trust fund	84,148	74,965
Other	32,739	44,428
Total	158,204	172,037
Utility Plant, at Original Cost		
Electric	4,841,355	4,700,983
Less-accumulated depreciation	2,196,835	2,082,419
Net utility plant in service	2,644,520	2,618,564
Construction work in progress	53,821	53,250
Nuclear fuel, net of amortization of $127,631 and $113,472	36,109	29,120
Total	2,734,450	2,700,934
Deferred Charges		
Regulatory assets	144,345	145,627
Prepaid pension costs	119,811	108,247
Goodwill	86,767	26,105
Other deferred charges	63,087	31,628
Total	414,010	311,607
Total	$ 3,798,901	$ 3,681,950

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

GREAT PLAINS ENERGY
Consolidated Balance Sheets

	December 31 2004	December 31 2003
LIABILITIES AND CAPITALIZATION	(thousands)	
Current Liabilities		
Notes payable	$ 20,000	$ 87,000
Current maturities of long-term debt	253,230	59,303
EIRR bonds classified as current	85,922	129,288
Accounts payable	199,952	186,747
Accrued taxes	46,993	39,886
Accrued interest	11,598	11,937
Accrued payroll and vacations	32,462	34,762
Accrued refueling outage costs	13,180	1,760
Supplier collateral	7,700	20,850
Liabilities of discontinued operations	2,129	4,607
Other	24,931	28,944
Total	698,097	605,084
Deferred Credits and Other Liabilities		
Deferred income taxes	632,160	609,333
Deferred investment tax credits	33,587	37,571
Asset retirement obligations	113,674	106,694
Pension liability	95,805	89,488
Other	88,524	79,141
Total	963,750	922,227
Capitalization		
Common stock equity		
Common stock-150,000,000 shares authorized without par value 74,394,423 and 69,259,203 shares issued, stated value	765,482	611,424
Unearned compensation	(1,393)	(1,633)
Capital stock premium and expense	(32,112)	(7,240)
Retained earnings	451,491	391,750
Treasury stock-28,488 and 3,265 shares, at cost	(856)	(121)
Accumulated other comprehensive loss	(41,018)	(36,886)
Total	1,141,594	957,294
Cumulative preferred stock $100 par value		
3.80% - 100,000 shares issued	10,000	10,000
4.50% - 100,000 shares issued	10,000	10,000
4.20% - 70,000 shares issued	7,000	7,000
4.35% - 120,000 shares issued	12,000	12,000
Total	39,000	39,000
Long-term debt (Note 19)	956,460	1,158,345
Total	2,137,054	2,154,639
Commitments and Contingencies (Note 13)		
Total	$ 3,798,901	$ 3,681,950

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

GREAT PLAINS ENERGY
Consolidated Statements of Cash Flows

Year Ended December 31	2004	2003	2002
Cash Flows from Operating Activities		(thousands)	
Net income	$ 180,811	$ 144,923	$ 126,188
Less: Discontinued operations, net of income taxes	7,276	(44,779)	(7,514)
Income from continuing operations	173,535	189,702	133,702
Adjustments to reconcile income to net cash from operating activities:			
Cumulative effect of a change in accounting principles	-	-	3,000
Depreciation and amortization	150,071	142,763	146,757
Amortization of:			
Nuclear fuel	14,159	12,334	13,109
Other	11,827	11,626	12,461
Deferred income taxes, net	20,286	30,471	12,009
Investment tax credit amortization	(3,984)	(3,994)	(4,183)
Loss from equity investments	1,531	2,018	1,173
(Gain) loss on property	5,133	(23,703)	(1,376)
Deferred storm costs	-	-	(20,149)
Minority interest in subsidiaries	(2,131)	7,764	10,753
Other operating activities (Note 2)	6,693	(2,254)	25,067
Net cash from operating activities	377,120	366,727	332,323
Cash Flows from Investing Activities			
Utility capital expenditures	(190,548)	(148,675)	(131,158)
Allowance for borrowed funds used during construction	(1,498)	(1,368)	(979)
Purchases of investments	(38,556)	(3,520)	(7,134)
Purchases of nonutility property	(6,108)	(3,256)	(2,788)
Proceeds from sale of assets and investments	43,949	32,556	7,821
Purchase of additional indirect interest in Strategic Energy	(90,033)	-	-
Hawthorn No. 5 partial insurance recovery	30,810	3,940	-
Hawthorn No. 5 partial litigation settlements	1,139	17,263	-
Other investing activities	(7,081)	(1,220)	(3,748)
Net cash from investing activities	(257,926)	(104,280)	(137,986)
Cash Flows from Financing Activities			
Issuance of common stock	153,662	-	151,800
Issuance of long-term debt	163,600	-	224,539
Issuance costs	(14,496)	(266)	(9,962)
Repayment of long-term debt	(213,943)	(133,181)	(238,384)
Net change in short-term borrowings	(67,000)	43,846	(172,001)
Dividends paid	(120,806)	(116,527)	(107,424)
Other financing activities	(7,309)	(7,598)	(5,517)
Net cash from financing activities	(106,292)	(213,726)	(156,949)
Net Change in Cash and Cash Equivalents	12,902	48,721	37,388
Cash and Cash Equivalents from Continuing Operations at Beginning of Year	114,227	65,506	28,118
Cash and Cash Equivalents from Continuing Operations at End of Year	$ 127,129	$ 114,227	$ 65,506
Net Change in Cash and Cash Equivalents from Discontinued Operations	$ 458	$ 73	$ (821)
Cash and Cash Equivalents from Discontinued Operations at Beginning of Year	168	95	916
Cash and Cash Equivalents from Discontinued Operations at End of Year	$ 626	$ 168	$ 95

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

GREAT PLAINS ENERGY
Consolidated Statements of Common Stock Equity

	2004		2003		2002	
	Shares	**Amount**	Shares	Amount	Shares	Amount
Common Stock			(thousands, except share amounts)			
Beginning balance	**69,259,203**	**$ 611,424**	69,196,322	$ 609,497	61,908,726	$ 449,697
Issuance of common stock	**5,121,887**	**153,662**	-	-	7,287,596	159,800
Issuance of restricted common stock	**13,333**	**396**	62,881	1,927	-	-
Ending balance	**74,394,423**	**765,482**	69,259,203	611,424	69,196,322	609,497
Unearned Compensation						
Beginning balance		**(1,633)**		-		-
Issuance of restricted common stock		**(396)**		(1,927)		-
Compensation expense recognized		**636**		294		-
Ending balance		**(1,393)**		(1,633)		-
Capital Stock Premium and Expense						
Beginning balance		**(7,240)**		(7,744)		(1,656)
Issuance of common stock		**(5,434)**		-		(6,096)
FELINE PRIDES℠ purchase contract adjustment, allocated fees and expenses		**(19,603)**		-		-
Other		**165**		504		8
Ending balance		**(32,112)**		(7,240)		(7,744)
Retained Earnings						
Beginning balance		**391,750**		363,579		344,815
Net income		**180,811**		144,923		126,188
Loss on reissuance of treasury stock		**(193)**		-		-
Dividends:						
Common stock		**(119,160)**		(114,881)		(105,778)
Preferred stock - at required rates		**(1,646)**		(1,646)		(1,646)
Options		**(71)**		(225)		-
Ending balance		**451,491**		391,750		363,579
Treasury Stock						
Beginning balance	**(3,265)**	**(121)**	(152)	(4)	(35,916)	(903)
Treasury shares acquired	**(54,683)**	**(1,645)**	(85,000)	(2,332)	(17,000)	(435)
Treasury shares reissued	**29,460**	**910**	81,887	2,215	52,764	1,334
Ending balance	**(28,488)**	**(856)**	(3,265)	(121)	(152)	(4)
Accumulated Other Comprehensive Loss						
Beginning balance		**(36,886)**		(25,858)		(13,141)
Derivative hedging activity, net of tax		**931**		(598)		13,037
Minimum pension obligation, net of tax		**(5,063)**		(10,430)		(25,754)
Ending balance		**(41,018)**		(36,886)		(25,858)
Total Common Stock Equity		**$ 1,141,594**		$ 957,294		$ 939,470

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

GREAT PLAINS ENERGY
Consolidated Statements of Comprehensive Income

Year Ended December 31	2004	2003	2002
		(thousands)	
Net income	**$ 180,811**	$ 144,923	$ 126,188
Other comprehensive income			
Gain on derivative hedging instruments	**2,649**	7,712	17,584
Income taxes	**(1,126)**	(3,359)	(7,138)
Net gain on derivative hedging instruments	**1,523**	4,353	10,446
Reclassification to revenues and expenses, net of tax	**(592)**	(4,951)	2,591
Derivative hedging activity, net of tax	**931**	(598)	13,037
Change in minimum pension obligation	**(7,624)**	(17,100)	(42,218)
Income taxes	**2,561**	6,670	16,464
Net change in minimum pension obligation	**(5,063)**	(10,430)	(25,754)
Comprehensive income	**$ 176,679**	$ 133,895	$ 113,471

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

KANSAS CITY POWER & LIGHT COMPANY
Consolidated Statements of Income

Year Ended December 31	2004	2003	2002
Operating Revenues		(thousands)	
Electric revenues	$ 1,090,067	$ 1,054,900	$ 1,009,868
Other revenues	1,568	2,101	2,918
Total	1,091,635	1,057,001	1,012,786
Operating Expenses			
Fuel	179,362	160,327	159,666
Purchased power	52,533	53,163	46,214
Other	259,699	241,701	224,618
Maintenance	83,535	85,391	91,333
Depreciation and amortization	145,246	140,955	145,569
General taxes	98,984	95,590	95,546
(Gain) loss on property	5,133	(1,603)	(178)
Total	824,492	775,524	762,768
Operating income	267,143	281,477	250,018
Non-operating income	5,402	5,251	4,641
Non-operating expenses	(7,407)	(8,280)	(8,830)
Interest charges	(74,170)	(70,294)	(80,306)
Income from continuing operations before income taxes and minority interest in subsidiaries	190,968	208,154	165,523
Income taxes	(52,763)	(83,572)	(62,857)
Minority interest in subsidiaries	5,087	1,263	-
Income from continuing operations	143,292	125,845	102,666
Discontinued operations, net of income taxes (Note 7)	-	(8,690)	(3,967)
Cumulative effect of a change in accounting principle (Note 5)	-	-	(3,000)
Net income	$ 143,292	$ 117,155	$ 95,699

The disclosures regarding KCP&L included in the accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

KANSAS CITY POWER & LIGHT COMPANY
Consolidated Balance Sheets

	December 31 2004	2003
ASSETS	(thousands)	
Current Assets		
Cash and cash equivalents	$ 51,619	$ 26,520
Receivables, net	63,366	95,635
Fuel inventories, at average cost	21,121	22,543
Materials and supplies, at average cost	54,432	56,599
Deferred income taxes	12,818	686
Other	12,874	8,611
Total	216,230	210,594
Nonutility Property and Investments		
Nuclear decommissioning trust fund	84,148	74,965
Other	20,576	34,255
Total	104,724	109,220
Utility Plant, at Original Cost		
Electric	4,841,355	4,700,983
Less-accumulated depreciation	2,196,835	2,082,419
Net utility plant in service	2,644,520	2,618,564
Construction work in progress	53,821	53,046
Nuclear fuel, net of amortization of $127,631 and $113,472	36,109	29,120
Total	2,734,450	2,700,730
Deferred Charges		
Regulatory assets	144,345	145,627
Prepaid pension costs	116,024	106,888
Other deferred charges	21,621	29,517
Total	281,990	282,032
Total	$ 3,337,394	$ 3,302,576

The disclosures regarding KCP&L included in the accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

KANSAS CITY POWER & LIGHT COMPANY
Consolidated Balance Sheets

	December 31 2004	2003
LIABILITIES AND CAPITALIZATION	(thousands)	
Current Liabilities		
Notes payable to Great Plains Energy	$ 24	$ 21,983
Current maturities of long-term debt	250,000	54,500
EIRR bonds classified as current	85,922	129,288
Accounts payable	84,105	82,353
Accrued taxes	34,497	41,114
Accrued interest	9,800	11,763
Accrued payroll and vacations	22,870	20,486
Accrued refueling outage costs	13,180	1,760
Other	8,327	8,619
Total	508,725	371,866
Deferred Credits and Other Liabilities		
Deferred income taxes	654,055	641,673
Deferred investment tax credits	33,587	37,571
Asset retirement obligations	113,674	106,694
Pension liability	90,491	84,434
Other	46,933	52,196
Total	938,740	922,568
Capitalization		
Common stock equity		
Common stock-1,000 shares authorized without par value 1 share issued, stated value	887,041	662,041
Retained earnings	252,893	228,761
Accumulated other comprehensive loss	(40,334)	(35,244)
Total	1,099,600	855,558
Long-term debt (Note 19)	790,329	1,152,584
Total	1,889,929	2,008,142
Commitments and Contingencies (Note 13)		
Total	$ 3,337,394	$ 3,302,576

The disclosures regarding KCP&L included in the accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

KANSAS CITY POWER & LIGHT COMPANY
Consolidated Statements of Cash Flows

Year Ended December 31	2004	2003	2002
Cash Flows from Operating Activities		(thousands)	
Net income	**$ 143,292**	$ 117,155	$ 95,699
Less: Discontinued operations, net of income taxes	**-**	(8,690)	(3,967)
Income from continuing operations	**143,292**	125,845	99,666
Adjustments to reconcile income to net cash from operating activities:			
Cumulative effect of a change in accounting principles	**-**	-	3,000
Depreciation and amortization	**145,246**	140,955	145,569
Amortization of:			
Nuclear fuel	**14,159**	12,334	13,109
Other	**7,719**	9,350	9,546
Deferred income taxes, net	**10,861**	34,285	11,355
Investment tax credit amortization	**(3,984)**	(3,994)	(4,183)
(Gain) loss on property	**5,133**	(1,603)	(178)
Deferred storm costs	**-**	-	(20,149)
Minority interest in subsidiaries	**(5,087)**	(1,263)	-
Other operating activities (Note 2)	**(1,080)**	(34,536)	21,178
Net cash from operating activities	**316,259**	281,373	278,913
Cash Flows from Investing Activities			
Utility capital expenditures	**(190,548)**	(148,675)	(132,039)
Allowance for borrowed funds used during construction	**(1,498)**	(1,368)	(979)
Purchases of investments	**(3,553)**	(3,520)	(3,421)
Purchases of nonutility property	**(254)**	(147)	(225)
Proceeds from sale of assets	**7,465**	4,135	-
Hawthorn No. 5 partial insurance recovery	**30,810**	3,940	-
Hawthorn No. 5 partial litigation settlements	**1,139**	17,263	-
Other investing activities	**(7,100)**	(4,045)	(4,084)
Net cash from investing activities	**(163,539)**	(132,417)	(140,748)
Cash Flows from Financing Activities			
Issuance of long-term debt	**-**	-	224,539
Repayment of long-term debt	**(209,140)**	(124,000)	(227,000)
Net change in short-term borrowings	**(21,959)**	(341)	(61,750)
Dividends paid to Great Plains Energy	**(119,160)**	(98,000)	(105,617)
Equity contribution from Great Plains Energy	**225,000**	100,000	36,000
Issuance costs	**(2,362)**	(266)	(4,269)
Net cash from financing activities	**(127,621)**	(122,607)	(138,097)
Net Change in Cash and Cash Equivalents	**25,099**	26,349	68
Cash and Cash Equivalents from Continuing Operations at Beginning of Year	**26,520**	171	103
Cash and Cash Equivalents from Continuing Operations at End of Year	**$ 51,619**	$ 26,520	$ 171
Net Change in Cash and Cash Equivalents from Discontinued Operations	**$ -**	$ (307)	$ (552)
Cash and Cash Equivalents from Discontinued Operations at Beginning of Year	**-**	307	859
Cash and Cash Equivalents from Discontinued Operations at End of Year	**$ -**	$ -	$ 307

The disclosures regarding KCP&L included in the accompanying Notes to Consolidated Financial Statements are an integral par of these statements.

KANSAS CITY POWER & LIGHT COMPANY
Consolidated Statements of Common Stock Equity

	2004		2003		2002	
	Shares	Amount	Shares	Amount	Shares	Amount
Common Stock	(thousands, except share amounts)					
Beginning balance	1	$ 662,041	1	$ 562,041	1	$ 526,041
Equity contribution from Great Plains Energy	-	225,000	-	100,000	-	36,000
Ending balance	1	887,041	1	662,041	1	562,041
Retained Earnings						
Beginning balance		228,761		209,606		219,524
Net income		143,292		117,155		95,699
Dividends:						
Common stock held by Great Plains Energy		(119,160)		(98,000)		(105,617)
Ending balance		252,893		228,761		209,606
Accumulated Other Comprehensive Loss						
Beginning balance		(35,244)		(26,614)		(1,182)
Derivative hedging activity, net of tax		(233)		(83)		322
Minimum pension obligation, net of tax		(4,857)		(8,547)		(25,754)
Ending balance		(40,334)		(35,244)		(26,614)
Total Common Stock Equity		$ 1,099,600		$ 855,558		$ 745,033

The disclosures regarding KCP&L included in the accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

KANSAS CITY POWER & LIGHT COMPANY
Consolidated Statements of Comprehensive Income

Year Ended December 31	2004	2003	2002
		(thousands)	
Net income	**$ 143,292**	$ 117,155	$ 95,699
Other comprehensive income			
Gain on derivative hedging instruments	**280**	657	702
Income taxes	**(111)**	(256)	(274)
Net gain on derivative hedging instruments	**169**	401	428
Reclassification to revenues and expenses, net of tax	**(402)**	(484)	(106)
Derivative hedging activity, net of tax	**(233)**	(83)	322
Change in minimum pension obligation	**(7,321)**	(14,012)	(42,218)
Income taxes	**2,464**	5,465	16,464
Net change in minimum pension obligation	**(4,857)**	(8,547)	(25,754)
Comprehensive income	**$ 138,202**	$ 108,525	$ 70,267

The disclosures regarding KCP&L included in the accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

GREAT PLAINS ENERGY INCORPORATED
KANSAS CITY POWER & LIGHT COMPANY
Notes to Consolidated Financial Statements

The notes to consolidated financial statements that follow are a combined presentation for Great Plains Energy Incorporated and Kansas City Power & Light Company, both registrants under this filing. The terms "Great Plains Energy," "Company," "KCP&L" and "consolidated KCP&L" are used throughout this report. "Great Plains Energy" and the "Company" refer to Great Plains Energy Incorporated and its consolidated subsidiaries, unless otherwise indicated. "KCP&L" refers to Kansas City Power & Light Company, and "consolidated KCP&L" refers to KCP&L and its consolidated subsidiaries.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization

Great Plains Energy, a Missouri corporation incorporated in 2001, is a public utility holding company registered with and subject to the regulation of the Securities and Exchange Commission (SEC) under the Public Utility Holding Company Act of 1935, as amended (35 Act). Great Plains Energy does not own or operate any significant assets other than the stock of its subsidiaries.

Great Plains Energy has five direct subsidiaries:

- KCP&L is an integrated, regulated electric utility, which provides electricity to customers primarily in the states of Missouri and Kansas. KCP&L's wholly owned subsidiary, Home Service Solutions Inc. (HSS) has invested in Worry Free Service, Inc. (Worry Free). HSS entered into a letter of intent to sell Worry Free in December 2004 and closed the sale in February 2005. Prior to the June 2003 disposition of R.S. Andrews Enterprises, Inc. (RSAE), HSS held an investment in RSAE. See Note 7 for additional information concerning the June 2003 disposition of RSAE.
- KLT Inc. is an intermediate holding company that primarily holds, directly or indirectly, interests in Strategic Energy, L.L.C. (Strategic Energy) and affordable housing limited partnerships. Strategic Energy provides competitive electricity supply services in several electricity markets offering retail choice. KLT Inc. wholly owns KLT Gas Inc. (KLT Gas). In February 2004, the Board of Directors approved the sale of the KLT Gas natural gas properties (KLT Gas portfolio) and discontinuation of the gas business. KLT Gas completed sales of substantially all of the KLT Gas portfolio in 2004. See Note 6 for additional information.
- Great Plains Power Incorporated (GPP) focuses on the development of wholesale generation. Management decided during 2002 to limit the operations of GPP to the siting and permitting process that began in 2001 for potential new generation. GPP has made no significant investments to date.
- Innovative Energy Consultants Inc. (IEC) is an intermediate holding company that holds an indirect interest in Strategic Energy. IEC does not own or operate any assets other than its indirect interest in Strategic Energy. When combined with KLT Inc.'s indirect interest in Strategic Energy, the Company owns just under 100% of the indirect interest in Strategic Energy.
- Great Plains Energy Services Incorporated (Services) was formed to provide services at cost to Great Plains Energy and its subsidiaries, including consolidated KCP&L, as a service company under the 35 Act.

The operations of Great Plains Energy and its subsidiaries are divided into two reportable segments, KCP&L and Strategic Energy. Great Plains Energy's legal structure differs from the functional management and financial reporting of its reportable segments. Other activities not considered a reportable segment include the operations of HSS, GPP, Services, all KLT Inc. operations other than Strategic Energy, and holding company operations.

Financial Statement Presentation
Certain prior year amounts have been reclassified to conform to current year presentation.

Cash and Cash Equivalents
Cash equivalents consist of highly liquid investments with original maturities of three months or less. For Great Plains Energy this includes Strategic Energy's cash held in trust of $21.0 million and $16.1 million at December 31, 2004 and 2003, respectively.

Strategic Energy has entered into collateral arrangements with selected electricity power suppliers that require selected customers to remit payment to lockboxes that are held in trust and managed by a Trustee. As part of the trust administration, the Trustee remits payment to the supplier of electricity purchased by Strategic Energy. On a monthly basis, any remittances into the lockboxes in excess of disbursements to the supplier are remitted back to Strategic Energy.

Restricted Cash
Strategic Energy has entered into Master Power Purchase and Sale Agreements with its power suppliers. Certain of these agreements contain provisions whereby, to the extent Strategic Energy has a net exposure to the purchased power supplier, collateral requirements are to be maintained. Collateral posted in the form of cash to Strategic Energy is restricted by agreement, but would become unrestricted in the event of a default by the purchased power supplier. Restricted cash collateral at December 31, 2004 and 2003, was $7.7 million and $20.9 million, respectively.

Fair Value of Financial Instruments
The following methods and assumptions were used to estimate the fair value of each class of financial instruments for which it is practicable to estimate that value.

Nonutility Property and Investments – Consolidated KCP&L's investments and nonutility property includes the nuclear decommissioning trust fund recorded at fair value. Fair value is based on quoted market prices of the investments held by the fund. In addition to consolidated KCP&L's investments, Great Plains Energy's investments and nonutility property include KLT Investments Inc.'s (KLT Investments) affordable housing limited partnerships. The fair value of KLT Investments' affordable housing limited partnership total portfolio, based on the discounted cash flows generated by tax credits, tax deductions and sale of properties, approximates book value. The fair values of other various investments are not readily determinable and the investments are therefore stated at cost.

Long-term Debt – The incremental borrowing rate for similar debt was used to determine fair value if quoted market prices were not available. Great Plains Energy's and consolidated KCP&L's book values of long-term debt were between 3% and 4% below fair values at December 31, 2004.

Derivative Instruments
The Company accounts for derivative instruments in accordance with Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended. This statement generally requires derivative instruments to be recorded on the balance sheet at fair value and establishes criteria for designation and effectiveness of hedging relationships. The Company enters into derivative contracts to manage its exposure to commodity price fluctuations and interest rate risk. All derivative instruments are used solely for hedging purposes and are not issued or held for speculative reasons.

The Company's policy is to elect normal purchases and normal sales exception (NPNS), in accordance with SFAS No. 133, for derivative contracts that qualify for this accounting treatment. The appropriate accounting treatment for NPNS designation for derivative contracts is accrual accounting, which requires the effects of the derivative to be recorded when the derivative contract settles.

The Company records derivative instruments that are not accounted for as NPNS as assets or liabilities on the consolidated balance sheets at fair value. The fair value of derivative instruments is estimated using market quotes, over-the-counter forward price and volatility curves and correlation among power and fuel prices, net of estimated credit risk. Changes in the fair value of derivatives are recorded each period in net income unless specific hedge accounting criteria are met. Changes in the fair value of derivative instruments recorded to other comprehensive income (OCI) are reclassified to revenues and expenses in the period when the forecasted transaction occurs. The portion of the change in fair value of a derivative instrument determined to be ineffective is immediately recognized in net income. See Note 21 for additional information regarding derivative financial instruments and hedging activities.

Investments in Affordable Housing Limited Partnerships
At December 31, 2004, KLT Investments had $41.3 million in affordable housing limited partnerships. Approximately 65% of these investments were recorded at cost; the equity method was used for the remainder. Tax expense is reduced in the year tax credits are generated. The investments generate future cash flows from tax credits and tax losses of the partnerships. The investments also generate cash flows from the sales of the properties. For most investments, tax credits are received over ten years. A change in accounting principle relating to investments made after May 19, 1995, requires the use of the equity method when a company owns more than 5% in a limited partnership investment. Of the investments recorded at cost, $26.0 million exceed this 5% level but were made before May 19, 1995. Management does not anticipate making additional investments in affordable housing limited partnerships at this time.

On a quarterly basis, KLT Investments compares the cost of those properties accounted for by the cost method to the total of projected residual value of the properties and remaining tax credits to be received. Based on the latest comparison, KLT Investments reduced its investments in affordable housing limited partnerships by $7.5 million, $11.0 million and $9.0 million in 2004, 2003 and 2002, respectively. These amounts are included in Non-operating expenses on Great Plains Energy's consolidated statements of income. The properties underlying the partnership investments are subject to certain risks inherent in real estate ownership and management.

Natural Gas Properties Included in Assets of Discontinued Operations
During 2004, KLT Gas completed sales of substantially all of the KLT Gas portfolio, and natural gas properties had a zero-balance at December 31, 2004. At December 31, 2003, natural gas property and equipment included in Assets of Discontinued Operations on Great Plains Energy's consolidated balance sheets totaled $9.8 million, net of $63.8 million of accumulated depreciation and impairments. See Note 6 for information regarding the impairment and sale of KLT Gas assets and discontinued operations.

Other Nonutility Property
Great Plains Energy's and consolidated KCP&L's other nonutility property includes land, buildings, vehicles, general office equipment and software and is recorded at historical cost, net of accumulated depreciation, and has a range of estimated useful lives of 3 to 50 years.

Utility Plant
KCP&L's utility plant is stated at historical costs of construction. These costs include taxes, an allowance for the cost of borrowed and equity funds used to finance construction and payroll-related costs, including pensions and other fringe benefits. Replacements, improvements and additions to

units of property are capitalized. Repairs of property and replacements of items not considered to be units of property are expensed as incurred (except as discussed under Wolf Creek Refueling Outage Costs). When property units are retired or otherwise disposed, the original cost, net of salvage, is charged to accumulated depreciation. Substantially all utility plant is pledged as collateral for KCP&L's mortgage bonds under the General Mortgage Indenture and Deed of Trust dated December 1, 1986, as supplemented.

The balances of utility plant in service with a range of estimated useful lives are listed in the following table.

December 31	2004	2003
Utility Plant In Service	(millions)	
Production (23 - 42 years)	$ 2,938.5	$ 2,913.9
Transmission (27 - 76 years)	315.5	308.3
Distribution (8 - 75 years)	1,320.0	1,261.6
General (5 - 50 years)	267.4	217.2
Total [a]	$ 4,841.4	$ 4,701.0

[a] Includes $89.1 million and $66.7 million of land and other assets for which depreciation was not recorded in 2004 and 2003, respectively.

Through December 31, 2004, KCP&L had received $194.8 million in insurance recoveries related to property destroyed in the 1999 explosion at the Hawthorn No. 5 generating unit. An additional $10.0 million in insurance recoveries was received in early 2005. Additionally, KCP&L filed suit against multiple defendants who are alleged to have responsibility for the explosion. Various defendants have settled with KCP&L for a total of $38.2 million through December 31, 2004, of which $18.5 million was recorded as a recovery of capital expenditures. Recoveries received related to property destroyed and subrogation settlements recorded as a recovery of capital expenditures have been recorded as an increase in accumulated depreciation.

As prescribed by the Federal Energy Regulatory Commission (FERC), Allowance for Funds used During Construction (AFDC) is charged to the cost of the plant. AFDC is included in the rates charged to customers by KCP&L over the service life of the property. AFDC equity funds are included as a non-cash item in non-operating income and AFDC borrowed funds are a reduction of interest charges. The rates used to compute gross AFDC are compounded semi-annually and averaged 8.6% in 2004, 8.2% in 2003 and 4.4% in 2002.

In 2001, the American Institute of Certified Public Accountants issued an exposure draft on a proposed Statement of Position (SOP) "Accounting for Certain Costs and Activities Related to Property, Plant, and Equipment." In 2004, the Financial Accounting Standards Board (FASB) objected to final clearance of the proposed SOP and removed the project from its agenda. No further discussion or action related to this SOP is expected.

Depreciation, Depletion and Amortization

Depreciation and amortization of KCP&L's utility plant other than nuclear fuel is computed using the straight-line method over the estimated lives of depreciable property based on rates approved by state regulatory authorities. Annual depreciation rates average about 3%. Nuclear fuel is amortized to fuel expense based on the quantity of heat produced during the generation of electricity.

Depreciation of nonutility property is computed using the straight-line method. Consolidated KCP&L's nonutility property annual depreciation rates for 2004, 2003 and 2002 were 12.3%, 11.5% and 10.7%, respectively. Other Great Plains Energy nonutility property annual depreciation rates for 2004, 2003 and 2002 were 24.2%, 21.2% and 15.7%, respectively. Other Great Plains Energy's nonutility property includes Strategic Energy's depreciable assets, which are primarily software costs and are amortized over a shorter time period, three years, resulting in a higher annual depreciation rate.

As part of the acquisition of additional interest in Strategic Energy, IEC recorded intangible assets that have finite lives and are subject to amortization. These intangible assets include the fair value of acquired supply contracts, customer relationships and asset information systems, which are being amortized over 28, 72 and 44 months, respectively. See Note 8 for additional discussion of the May 2004 acquisition of an additional indirect interest in Strategic Energy.

Natural gas properties sold in 2004 were included in Assets of Discontinued Operations in 2003. Depletion, depreciation and amortization of natural gas properties were calculated using the units of production method. After deciding to exit the gas business, the Company ceased recording depletion and as such, there was no significant depletion recorded in 2004. The depletion per mmBtu was $2.78 in 2003 and $4.61 in 2002. The depletion per mmBtu in 2002 reflected downward revisions in reserve estimates. Unproved gas properties were not amortized but were assessed for impairment either individually or on an aggregated basis.

Spent Nuclear Fuel and Radioactive Waste

Under the Nuclear Waste Policy Act of 1982, the Department of Energy (DOE) is responsible for the permanent disposal of spent nuclear fuel. KCP&L pays the DOE a quarterly fee of one-tenth of a cent for each kilowatt-hour of net nuclear generation delivered and sold for the future disposal of spent nuclear fuel. These disposal costs are charged to fuel expense. In 2002, the U.S. Senate approved Yucca Mountain, Nevada as a long-term geologic repository. The DOE is currently in the process of preparing an application to obtain the Nuclear Regulatory Commission (NRC) license to proceed with construction of the repository. Management cannot predict when this site may be available. Under current DOE policy, once a permanent site is available, the DOE will accept spent nuclear fuel first from the owners with the oldest spent fuel. Wolf Creek Generating Station (Wolf Creek) has completed an on-site storage facility that is designed to hold all spent fuel generated at the plant through the end of its 40-year licensed life in 2025.

In January 2004, KCP&L and the other two Wolf Creek owners filed suit against the United States in the U.S. Court of Federal Claims seeking an unspecified amount of monetary damages resulting from the government's failure to begin accepting spent fuel for disposal in January 1998, as the government was required to do by the Nuclear Waste Policy Act of 1982. About sixty other similar cases are pending before that court, four of which went to trial in 2004. Another federal court already has determined that the government breached its obligation to begin accepting spent fuel for disposal. The questions now before the court in the pending cases are whether and to what extent the utilities are entitled to monetary damages for that breach. KCP&L cannot predict the outcome of the Wolf Creek case.

Wolf Creek Refueling Outage Costs

KCP&L accrues forecasted incremental costs to be incurred during scheduled Wolf Creek refueling outages monthly over the unit's operating cycle, normally about 18 months. Estimated incremental costs, which include operating, maintenance and replacement power expenses, are based on budgeted outage costs and the estimated outage duration. Changes to or variances from those estimates are recorded when known or are probable.

Nuclear Plant Decommissioning Costs

The Missouri Public Service Commission (MPSC) and The State Corporation Commission of the State of Kansas (KCC) require KCP&L and the other owners of Wolf Creek to submit an updated decommissioning cost study every three years. The most recent study was submitted to the MPSC and the KCC on August 30, 2002, and is the basis for the decommissioning cost estimates in the following table. Both the MPSC and the KCC have accepted the 2002 cost estimate as filed and have approved funding schedules for this cost estimate. The MPSC-approved schedule assumes funding through the expiration of Wolf Creek's current NRC operating license (2025). The KCC-approved schedule assumes that Wolf Creek will be granted a 20-year license extension and, thus, assumes funding through 2045. At this time, the owners of Wolf Creek have neither sought nor received a license extension from the NRC. The escalation rates and return on assets assumptions shown in the following table are those that were last explicitly approved by the MPSC and the KCC. The decommissioning cost estimates are based on the immediate dismantlement method and include the costs of decontamination, dismantlement and site restoration. KCP&L does not expect plant decommissioning to start before 2025.

	KCC	MPSC
Current cost of decommissioning (in 2002 dollars):	(millions)	
Total Station	$ 468	$ 468
47% share	220	220
Future cost of decommissioning (in 2025 dollars):		
Total Station		$ 1,288
47% share		606
Future cost of decommissioning (in 2045 dollars):		
Total Station	$ 2,527	
47% share	1,188	
Annual escalation factor	4.00%	4.50%
Annual return on trust assets [a]	6.02%	7.66%

[a] The 6.02% rate of return in Kansas is thru 2025. The rate systematically decreases to 3.99% from 2025 to decommissioning at the end of the extended 60-year life of 2045.

KCP&L currently contributes about $3.6 million annually to a tax-qualified trust fund to be used to decommission Wolf Creek. These costs are charged to other operating expense and recovered in billings to customers. If the actual return on trust assets is below the anticipated level, KCP&L believes a rate increase would be allowed ensuring full recovery of decommissioning costs over the remaining life of the station.

The trust fund balance, including reinvested earnings, was $84.1 million and $75.0 million at December 31, 2004 and 2003, respectively. The related liabilities for decommissioning are included in Asset Retirement Obligations (ARO).

The Company adopted SFAS No. 143, "Accounting for Asset Retirement Obligations" on January 1, 2003. See Note 16 for discussion of ARO including those associated with nuclear plant decommissioning costs.

Regulatory Matters

KCP&L is subject to the provisions of SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." Pursuant to SFAS No. 71, KCP&L defers items on the balance sheet resulting from the effects of the ratemaking process, which would not be recorded in accordance with Generally Accepted Accounting Principles (GAAP) if KCP&L were not regulated. See Note 4 for additional information concerning regulatory matters.

Revenue Recognition

KCP&L and Strategic Energy recognize revenues on sales of electricity when the service is provided. Receivables recorded at December 31, 2004 and 2003, include $31.2 million and $28.4 million, respectively, for electric services provided but not yet billed by KCP&L, and $103.0 million and $81.2 million, respectively, for electric services provided, but not yet billed by Strategic Energy. See Note 3 for additional information on receivables.

Strategic Energy primarily purchases power under forward physical delivery contracts to supply electricity to its retail energy customers. Strategic Energy sells any excess retail supply of electricity back into the wholesale market. The proceeds from the sale of excess supply of electricity are recorded as a reduction of purchased power. The amount of excess retail supply sales that reduced purchased power was $265.2 million, $160.4 million and $126.4 million in 2004, 2003 and 2002, respectively.

Allowance for Doubtful Accounts
This reserve represents estimated uncollectible accounts receivable and is based on management's judgment considering historical loss experience and the characteristics of existing accounts. Provisions for losses on receivables are charged to income to maintain the allowance at a level considered adequate to cover losses. Receivables are charged off against the reserve when they are deemed to be uncollectible.

Property Gains and Losses
Net gains and losses from the sales of assets, businesses and asset impairments are recorded in operating expenses. See Note 2 for information regarding the sale of RSAE.

Asset Impairments
Long-lived assets and finite lived intangible assets subject to amortization are periodically reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable as prescribed under SFAS No. 144 "Accounting for the Impairment or Disposal of Long-lived Assets." SFAS No. 144 requires that if the sum of the undiscounted expected future cash flows from an asset to be held and used is less than the carrying value of the asset, an asset impairment must be recognized in the financial statements. The amount of impairment recognized is the excess of the carrying value of the asset over its fair value. In December 2004, HSS entered into a letter of intent to sell Worry Free and recorded an asset impairment based on the valuation performed in connection with the sale.

Goodwill and indefinite lived intangible assets are tested for impairment at least annually and more frequently when indicators of impairment exist as prescribed under SFAS No. 142. SFAS No. 142 requires that if the fair value of a reporting unit is less than its carrying value including goodwill, an impairment charge for goodwill must be recognized in the financial statements. To measure the amount of the impairment loss to recognize, the implied fair value of the reporting unit goodwill would be compared with its carrying value. See Note 5 for additional information.

Income Taxes
In accordance with SFAS No. 109, "Accounting for Income Taxes," Great Plains Energy has recognized deferred taxes for all temporary book to tax differences using the liability method. The liability method requires that deferred tax balances be adjusted to reflect enacted tax rates that are anticipated to be in effect when the temporary differences reverse. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion of the deferred tax assets will not be realized.

Great Plains Energy and its subsidiaries file consolidated federal and combined and separate state income tax returns. Income taxes for consolidated or combined subsidiaries are allocated to the subsidiaries based on separate company computations of income or loss. In accordance with 35 Act requirements and the Company's intercompany tax allocation agreement, the holding company also allocates its own net income tax benefits to its direct subsidiaries based on the positive income of each company in the consolidated federal or combined state returns. Consistent with the ratemaking treatment, KCP&L uses the separate return method, adjusted for the allocation of parent company tax benefits, to compute its income tax provision.

KCP&L has established a regulatory asset for the additional future revenues to be collected from customers for deferred income taxes. Tax credits are recognized in the year generated except for certain KCP&L investment tax credits that have been deferred and amortized over the remaining service lives of the related properties.

Environmental Matters
Environmental costs are accrued when it is probable a liability has been incurred and the amount of the liability can be reasonably estimated.

Stock Options
The Company has an equity compensation plan, which is described more fully in Note 10. The Company adopted the fair value recognition provisions of SFAS No. 123, "Accounting for Stock-Based Compensation," for its stock options as of January 1, 2003. The Company has elected to use the modified prospective method of adoption as prescribed under SFAS No. 148, "Accounting for Stock-Based Compensation-Transition and Disclosure." Under the modified prospective method of adoption, stock option compensation cost recognized beginning January 1, 2003, is the same as if the fair value recognition provisions of SFAS No. 123 had been applied to all stock options granted after October 1, 1995.

In December 2004, FASB issued SFAS No. 123 (revised 2004) "Share-Based Payment," effective for reporting periods beginning after June 15, 2005. Management has determined that this statement will not have a significant impact on the Company's results of operations and financial position.

The following table illustrates the effect on net income and earnings per common share (EPS) for Great Plains Energy as if the fair value method had been applied in preparing the 2002 financial statements.

	2002
(thousands, except per share amounts)	
Net income, as reported	$ 126,188
Add: Stock-based employee compensation expense included in net income as reported, net of income taxes	57
Less: Total stock-based employee compensation expense determined under fair value based method for all awards, net of income taxes	255
Pro forma net income as if fair value method were applied	$ 125,990
Basic and diluted EPS, as reported	$ 1.99
Basic and diluted EPS, pro forma	$ 1.99

Basic and Diluted Earnings per Common Share Calculation
There was no significant dilutive effect on Great Plains Energy's EPS from other securities in 2004, 2003 and 2002. To determine basic EPS, preferred stock dividend requirements are deducted from income from continuing operations and net income before dividing by average number of common shares outstanding. The earnings (loss) per share impact of discontinued operations, net of income taxes, is determined by dividing discontinued operations, net of income taxes, by the average number of common shares outstanding. Diluted EPS assumes the issuance of common shares applicable to

stock options, performance shares, restricted stock and FELINE PRIDES calculated using the treasury stock method.

The following table reconciles Great Plains Energy's basic and diluted EPS from continuing operations.

	2004	2003	2002
Income	(thousands, except per share amounts)		
Income from continuing operations	$ 173,535	$ 189,702	$ 136,702
Less: preferred stock dividend requirements	1,646	1,646	1,646
Income available to common stockholders	$ 171,889	$ 188,056	$ 135,056
Common Shares Outstanding			
Average number of common shares outstanding	72,028	69,206	62,623
Add: effect of dilutive securities	64	42	1
Diluted average number of common shares outstanding	72,092	69,248	62,624
Basic EPS from continuing operations	$ 2.39	$ 2.72	$ 2.16
Diluted EPS from continuing operations	$ 2.39	$ 2.72	$ 2.16

As of December 31, 2004 and 2003, there were no anti-dilutive shares applicable to stock options, performance shares or restricted stock. As of December 31, 2004, 6.5 million FELINE PRIDES had no dilutive effect because the number of common shares to be issued in accordance with the settlement rate described in Note 19, assuming applicable market value equal to the average price during the period, would be equal to the number of shares Great Plains Energy could re-purchase in the market at the average price during the period. Options to purchase 394,723 shares of common stock as of December 31, 2002, were excluded from the computation of diluted EPS because they were anti-dilutive due to the option exercise prices being greater than the average market price of the common shares during the period.

In February 2005, the Board of Directors declared a quarterly dividend of $0.415 per share on Great Plains Energy's common stock. The common dividend is payable March 21, 2005, to shareholders of record as of February 28, 2005. The Board of Directors also declared regular dividends on the preferred stock, payable June 1, 2005, to shareholders of record on May 10, 2005.

2. SUPPLEMENTAL CASH FLOW INFORMATION

Great Plains Energy Other Operating Activities

	2004	2003	2002
Cash flows affected by changes in:		(thousands)	
Receivables	$ (36,517)	$ (13,077)	$ (50,200)
Fuel inventories	1,840	(821)	1,339
Materials and supplies	2,167	(5,799)	(104)
Accounts payable	43,261	6,331	(2,982)
Accrued taxes	7,107	21,777	48,756
Accrued interest	(1,006)	(4,184)	3,117
Wolf Creek refueling outage accrual	11,420	(6,532)	(4,687)
Pension and postretirement benefit assets and obligations	(10,387)	(20,545)	3,774
Allowance for equity funds used during construction	(2,087)	(1,424)	(299)
Other	(9,105)	22,020	26,353
Total other operating activities	$ 6,693	$ (2,254)	$ 25,067
Cash paid during the period:			
Interest	$ 84,082	$ 78,049	$ 82,132
Income taxes	$ 38,611	$ 42,440	$ 17,709

Consolidated KCP&L Other Operating Activities

	2004	2003	2002
Cash flows affected by changes in:		(thousands)	
Receivables	$ 1,649	$ (1,444)	$ (8,565)
Fuel inventories	1,840	(821)	1,339
Materials and supplies	2,167	(5,799)	(104)
Accounts payable	1,752	7,735	(35,963)
Accrued taxes	(6,617)	(2,792)	49,584
Accrued interest	(1,963)	(3,413)	4,107
Wolf Creek refueling outage accrual	11,420	(6,532)	(4,687)
Pension and postretirement benefit assets and obligations	(8,059)	(20,272)	3,774
Allowance for equity funds used during construction	(2,087)	(1,424)	(299)
Other	(1,182)	226	11,992
Total other operating activities	$ (1,080)	$ (34,536)	$ 21,178
Cash paid during the period:			
Interest	$ 73,840	$ 71,399	$ 74,068
Income taxes	$ 64,878	$ 68,112	$ 11,897

Significant Non-Cash Items

Asset Retirement Obligations

KCP&L adopted SFAS No. 143 on January 1, 2003, and recorded a liability for ARO of $99.2 million and increased property and equipment, net of accumulated depreciation, by $18.3 million. KCP&L is a regulated utility subject to the provisions of SFAS No. 71, and management believes it is probable that any differences between expenses under SFAS No. 143 and expenses recovered currently in rates will be recoverable in future rates. As a result, the $16.3 million net cumulative effect of the adoption of SFAS No. 143 was recorded as a regulatory asset; therefore, it had no impact on net income. The adoption of SFAS No. 143 had no effect on Great Plains Energy and consolidated KCP&L's cash flows.

FIN 46

KCP&L consolidated the Lease Trust and de-consolidated KCPL Financing I in 2003, as required by FASB Interpretation (FIN) No. 46, "Consolidation of Variable Interest Entities," as amended. As a result of the consolidation of the Lease Trust, Great Plains Energy's and consolidated KCP&L's long-term debt increased $143.8 million. The consolidation of the Lease Trust had no effect on Great Plains Energy's and consolidated KCP&L's cash flows. See Note 13 for additional information concerning the consolidation of the Lease Trust.

Prior to the de-consolidation of KCPL Financing I, Great Plains Energy and consolidated KCP&L reflected $150 million of 8.3% preferred securities issued by KCPL Financing I on their respective balance sheets. As a result of the de-consolidation, Great Plains Energy's and consolidated KCP&L's other nonutility property and investments increased $4.6 million representing the investment in the common securities of KCPL Financing I, and long-term debt increased $154.6 million representing the 8.3% Junior Subordinated Deferrable Interest Debentures issued by KCP&L and held by KCPL Financing I. The de-consolidation of KCPL Financing I had no effect on Great Plains Energy's and consolidated KCP&L's cash flows.

Minimum Pension Liability

Primarily as a result of lower discount rates and historical losses in the market value of plan assets, the Company recorded a minimum pension liability of $84.2 million offset by an intangible asset of $15.6 million and OCI of $68.6 million ($42.3 million net of tax) in 2004. In 2003, the Company's minimum pension liability was $78.4 million offset by an intangible asset of $17.4 million and OCI of $61.0 million ($37.2 million net of tax). Recording the minimum pension liabilities had no effect on Great Plains Energy's and consolidated KCP&L's cash flows.

RSAE Disposition

In 2003, HSS completed the disposition of its interest in RSAE. See Note 7 for additional information concerning the disposition of RSAE. The following table summarizes Great Plains Energy's and consolidated KCP&L's loss from discontinued operations as a result of this transaction.

Year to Date June 30	**2003**
	(thousands)
Cash repayment of supported bank line	$ (22,074)
Write-off of intercompany balance and investment	4,760
Accrued transaction costs	(1,550)
Income tax benefit	11,793
Loss on disposition	(7,071)
Pre-disposition operating losses	(1,619)
Discontinued operations	$ (8,690)

DTI Bankruptcy

On December 31, 2001, a subsidiary of KLT Telecom Inc. (KLT Telecom), DTI Holdings, Inc. and its subsidiaries, Digital Teleport, Inc. and Digital Teleport of Virginia, Inc., filed separate voluntary petitions in the Bankruptcy Court for the Eastern District of Missouri for reorganization under Chapter 11 of the U.S. Bankruptcy Code, which cases were procedurally consolidated. DTI Holdings and its two subsidiaries are collectively called "DTI." In December 2002, Digital Teleport entered into an agreement to sell substantially all of its assets to CenturyTel Fiber Company II, LLC, a nominee of CenturyTel, Inc., which was approved by the Bankruptcy Court and closed in 2003.

KLT Telecom received $19.2 million in 2003 related to the confirmation of the DTI bankruptcy. Pending final resolution of the MODOR Claim and the litigation regarding the put option of a minority shareholder, the effect of the DTI bankruptcy on the Company has been resolved. See Note 15 for information regarding the MODOR Claim and the put option.

The following table summarizes Great Plains Energy's gain on the sale of DTI assets.

DTI	2003
	(thousands)
Cash proceeds from bankruptcy estates	$ 19,234
Cash proceeds from sale of office building	1,186
Receivables	1,300
Total proceeds	21,720
Book basis of office building sold	(2,720)
DIP financing accrual reversal	5,000
Accounts payable	(1,900)
Income tax	(9,810)
Reversal of tax valuation allowance	15,779
Gain on sale of assets	$ 28,069

Strategic Energy Acquisition

During November 2002, Great Plains Energy indirectly acquired an additional 6% ownership in Strategic Energy through its subsidiary IEC. The $15.1 million consideration paid for the 6% ownership consisted of $8.0 million in Great Plains Energy common stock and promissory notes of $4.7 million (issued by Great Plains Energy) and $2.4 million (issued by IEC). The promissory notes were paid in January 2003. This transaction had no effect on Great Plains Energy's cash flows for the year ended December 31, 2002. See Note 8 for information regarding the purchase of an additional indirect interest in Strategic Energy in 2004.

3. RECEIVABLES

The Company's receivables are detailed in the following table.

December 31	2004	2003
	(thousands)	
Customer accounts receivable sold to Receivables Company	$ 19,866	$ 17,902
Consolidated KCP&L other receivables	43,500	77,733
Consolidated KCP&L receivables	63,366	95,635
Great Plains Energy other receivables	183,818	144,709
Great Plains Energy receivables	$ 247,184	$ 240,344

KCP&L entered into a revolving agreement to sell all of its right, title and interest in the majority of its customer accounts receivable to Kansas City Power & Light Receivables Company (Receivables Company), which in turn sold most of the receivables to outside investors. Accounts receivable sold under this revolving agreement totaled $84.9 million and $87.9 million at December 31, 2004 and 2003, respectively. These sales included unbilled receivables of $31.2 million and $28.4 million at December 31, 2004 and 2003, respectively. As a result of the sale to outside investors, Receivables Company received up to $70 million in cash, which was forwarded to KCP&L as consideration for its sale. At December 31, 2004 and 2003, Receivables Company had received $65.0 million and $70.0 million in cash, respectively. The agreement was structured as a true sale under which the creditors of Receivables Company were entitled to be satisfied out of the assets of Receivables Company prior to any value being returned to KCP&L or its creditors. The agreement expired in January 2005 and was not renewed by KCP&L. KCP&L is currently evaluating alternatives to replace this agreement and intends to enter into a new agreement in 2005.

Under the agreement, KCP&L sold its receivables at a fixed price based upon the expected cost of funds and charge-offs. These costs comprised KCP&L's loss on the sale of accounts receivable.

KCP&L serviced the receivables and received an annual servicing fee of 0.25% of the outstanding principal amount of the receivables sold and retained any late fees charged to customers.

Information regarding KCP&L's sale of accounts receivable is reflected in the following table.

	2004	2003	2002
		(thousands)	
Gross proceeds on sale of accounts receivable	$ 929,122	$ 939,498	$ 957,222
Collections	927,986	949,484	974,669
Loss on sale of accounts receivable	2,529	3,714	4,558
Late fees	2,210	2,256	2,572

Consolidated KCP&L's other receivables at December 31, 2004 and 2003, consist primarily of receivables from partners in jointly owned electric utility plants, wholesale sales receivables and accounts receivable held by Worry Free. The December 31, 2003, amounts also included insurance recoveries. Great Plains Energy's other receivables at December 31, 2004 and 2003, are primarily the accounts receivable held by Strategic Energy including unbilled receivables of $103.0 million and $81.2 million, respectively.

4. REGULATORY MATTERS

Regulatory Assets and Liabilities

KCP&L is subject to the provisions of SFAS No. 71. Accordingly, KCP&L has recorded assets and liabilities on its balance sheet resulting from the effects of the ratemaking process, which would not be recorded under GAAP for non-regulated entities. Regulatory assets represent costs incurred that have been deferred because future recovery in customer rates is probable. Regulatory liabilities generally represent probable future reductions in revenue or refunds to customers. KCP&L's continued ability to meet the criteria for application of SFAS No. 71 may be affected in the future by competitive forces and restructuring in the electric industry. In the event that SFAS No. 71 no longer applied to all, or a separable portion, of KCP&L's operations, the related regulatory assets and liabilities would be written off unless an appropriate regulatory recovery mechanism is provided. Additionally, these factors could result in an impairment of utility plant assets if the cost of the assets could not be expected to be recovered in customer rates. Whether an asset has been impaired is determined pursuant to SFAS No. 144.

	Amortization ending period	December 31 2004	2003
Regulatory Assets		(millions)	
Taxes recoverable through future rates		$ 81.0	$ 89.0
Decommission and decontaminate federal uranium enrichment facilities	2007	2.0	2.6
Loss on reacquired debt	2023	7.7	4.3
January 2002 incremental ice storm costs (Missouri)	2007	9.5	14.1
Change in depreciable life of Wolf Creek (Kansas)	2045	15.5	7.7
Cost of removal		13.9	14.5
Asset retirement obligations		11.4	12.9
Other [(a)]	Various	3.3	0.5
Total Regulatory Assets		$ 144.3	$ 145.6
Regulatory Liabilities			
Emission allowances [(b)]		$ (4.1)	$ (3.8)
Total Regulatory Liabilities		$ (4.1)	$ (3.8)

(a) An insignificant amount at December 31, 2004 and 2003, respectively, earns a return on investment in the rate making process.

(b) Consistent with the MPSC order establishing regulatory treatment, no amortization is being recorded.

The Company adopted SFAS No. 143 on January 1, 2003, and recorded liabilities for legal obligations to retire assets. In conjunction with the adoption of SFAS No. 143, non-legal costs of removal were reclassified for all periods presented from accumulated depreciation to a regulatory asset. See Note 16 for discussion of ARO. The change in the depreciable life of Wolf Creek in 2003 was the result of the KCC stipulation and agreement discussed below.

Retail Rate Matters

At the end of January 2002, a severe ice storm occurred throughout large portions of the Midwest, including the greater Kansas City metropolitan area. In 2002, the KCC approved a stipulation and agreement regarding the treatment of the $16.5 million Kansas jurisdictional portion of the ice storm costs. Pursuant to the stipulation and agreement, KCP&L implemented a retail rate reduction January 1, 2003, and began calculating depreciation expense on Wolf Creek using a 60-year life instead of a 40-year life. As a result of the stipulation and agreement, KCP&L's retail revenues decreased approximately $12.5 million and depreciation expense decreased approximately $7.7 million annually beginning in 2003. The reduction in depreciation expense has been recorded as a regulatory asset, as discussed above. KCP&L also agreed to file a rate case by May 15, 2006.

In 2002, the MPSC approved KCP&L's application for an accounting authority order related to the Missouri jurisdictional portion of the storm costs. The order allows KCP&L to defer and amortize $20.1 million, representing the Missouri portion of the storm costs, through January 2007. The amortization, which began in September 2002, is approximately $4.6 million annually for the remainder of the amortization period. The amortization totaled $1.5 million in 2002.

5. GOODWILL AND INTANGIBLE PROPERTY

In accordance with SFAS No. 142, goodwill is tested for impairment upon adoption and at least annually thereafter. The annual test must be performed at the same time each year.

Strategic Energy's annual impairment tests, conducted September 1, have been completed and there were no impairments of the Strategic Energy goodwill in 2004, 2003 or 2002. Goodwill reported on Great Plains Energy's consolidated balance sheets associated with the Company's ownership in Strategic Energy was $86.8 million and $26.1 million at December 31, 2004 and 2003, respectively.

See Note 8 for additional information concerning the acquisition of an additional indirect interest in Strategic Energy in 2004.

As a result of the transition impairment test of RSAE goodwill related to the adoption of SFAS No. 142 in 2002, the Company recorded a $3.0 million write-down of goodwill as a cumulative effect of a change in accounting principle. See Note 7 for additional information concerning the June 2003 disposition of RSAE.

Other Intangible Assets and Liabilities
KCP&L's electric utility plant on the consolidated balance sheets included intangible computer software of $27.4 million, net of accumulated amortization of $61.3 million, in 2004 and $33.6 million, net of accumulated amortization of $52.5 million, in 2003.

Other intangible assets on Great Plains Energy's consolidated balance sheets include other intangible computer software of $2.0 million, net of accumulated amortization of $3.4 million, in 2004 and $2.7 million, net of accumulated amortization of $1.8 million, in 2003. See Note 8 for information concerning the intangible assets and liabilities recorded as a result of the acquisition of an additional indirect interest in Strategic Energy.

Assets of Discontinued Operations on Great Plains Energy's consolidated balance sheets included no intangible assets at December 31, 2004, and included gross intangible drilling costs, before impairments, of $32.0 million at December 31, 2003. Assets of Discontinued Operations, including intangible drilling costs, were significantly written down at the end of 2003 in aggregate at the property level. See Note 6 for additional information.

6. KLT GAS DISCONTINUED OPERATIONS

In February 2004, the Board of Directors approved the sale of the KLT Gas portfolio and discontinuation of the gas business. Consequently, in 2004, the KLT Gas portfolio was reported as discontinued operations and KLT Gas' historical activities were reclassified in accordance with SFAS No. 144 for all periods presented.

In 2004, KLT Gas completed sales of substantially all of the KLT Gas portfolio for $23.5 million cash, net of $1.4 million of transaction costs. During 2003, the Company recorded a loss of $33.5 million in Discontinued Operations, net of income taxes, as a result of impairments recognized in accordance with SFAS No. 144. The following table summarizes the discontinued operations.

	2004	2003	2002
		(millions)	
Revenues	$ 1.6	$ 1.5	$ 1.1
Loss from operations, including impairments, before income taxes	(4.5)	(59.1)	(6.6)
Gain on sales of assets	16.8	-	-
Discontinued operations before income taxes	12.3	(59.1)	(6.6)
Income taxes	(5.0)	23.0	3.1
Discontinued operations, net of income taxes	$ 7.3	$ (36.1)	$ (3.5)

Assets and liabilities of the discontinued operations are summarized in the following table.

December 31	2004	2003
	(millions)	
Current assets	$ 0.7	$ 1.0
Gas property and investments	-	9.8
Other nonutility property and investments	-	0.3
Accrued taxes	-	6.7
Deferred income taxes	-	10.0
Total assets of discontinued operations	$ 0.7	$ 27.8
Current liabilities	$ 2.1	$ 2.8
Asset retirement obligations	-	1.8
Total liabilities of discontinued operations	$ 2.1	$ 4.6

7. DISPOSITION OF OWNERSHIP INTEREST IN R.S. ANDREWS ENTERPRISES, INC.

On June 13, 2003, HSS' board of directors approved a plan to dispose of its interest in residential services provider RSAE. On June 30, 2003, HSS completed the disposition of its interest in RSAE. The financial statements reflect RSAE as discontinued operations for all periods presented as prescribed under SFAS No. 144. The following table summarizes the discontinued operations.

	2003	2002
	(millions)	
Revenues	$ 31.8	$ 58.5
Loss from operations before income taxes	(1.6)	(4.0)
Loss on disposal before income taxes	(18.9)	-
Total loss on discontinued operations before income taxes	(20.5)	(4.0)
Income tax benefit [a]	11.8	-
Discontinued operations, net of income taxes	$ (8.7)	$ (4.0)

[a] Since RSAE was not included in Great Plains Energy's consolidated income tax returns, an income tax benefit was not recognized on RSAE's 2002 losses. RSAE had continual losses and therefore did not recognize tax benefits. The 2003 tax benefit reflects the tax effect of Great Plains Energy's disposition of its interest in RSAE. See Note 11 on income taxes.

8. ACQUISITION OF ADDITIONAL INDIRECT INTEREST IN STRATEGIC ENERGY

Effective May 6, 2004, Great Plains Energy, through IEC, completed its purchase of an additional 11.45% indirect interest in Strategic Energy bringing Great Plains Energy's indirect ownership interest in Strategic Energy to just under 100%. The Company paid cash of $90.0 million, including $1.2 million of transaction costs. In accordance with the purchase terms, the Company also recorded a $0.9 million liability for 2004 fractional dividends to the previous owner for its share of 2004 budgeted Strategic Energy dividends. See Notes 12 and 15 for additional discussion of the acquisition.

The purchase price allocation for the net assets acquired is detailed in the following table.

	2004
	(millions)
Other non-utility property and investments	$ 10.6
Goodwill	60.7
Other deferred charges	46.1
Total assets	117.4
Accounts payable	0.9
Other deferred credits and liabilities	26.5
Net assets acquired	$ 90.0

A third party valuation was prepared to assist in the Company's determination of the purchase price allocation. The acquired share of identifiable intangible assets and liabilities were recorded by IEC at fair value as part of the purchase price allocation. The acquired share of the fair value of the identifiable intangibles was a net asset of $19.6 million. The fair value of acquired supply (intangible asset) and retail (liability) contracts is being amortized over approximately 28 months. Other intangible assets recorded that have finite lives and are subject to amortization include customer relationships and asset information systems, which are being amortized over 72 and 44 months, respectively. Net amortization for 2004 was $2.2 million. A $0.7 million intangible asset for the Strategic Energy trade name was also recorded and deemed to have an indefinite life, and as such, is not being amortized.

9. PENSION PLANS AND OTHER EMPLOYEE BENEFITS

Pension Plans and Other Employee Benefits

The Company maintains defined benefit pension plans for substantially all employees, including officers, of KCP&L, Services and Wolf Creek Nuclear Operating Corporation (WCNOC). Pension benefits under these plans reflect the employees' compensation, years of service and age at retirement. The funding policy for the pension plans is to contribute amounts sufficient to meet the minimum funding requirements under the Employee Retirement Security Act of 1974 (ERISA) plus additional amounts as considered appropriate.

For defined benefit pension plans sponsored by Great Plains Energy, contributions and expense are allocated to KCP&L and Services based on labor costs of plan participants. Any additional minimum pension liability is allocated based on each companies' funded status per plan. The Company recognizes gains and losses incurred by the pension plans by amortizing over a five-year period the rolling five-year average of unamortized actuarial gains and losses.

In addition to providing pension benefits, the Company provides certain postretirement health care and life insurance benefits for substantially all retired employees of KCP&L, Services and WCNOC. The cost of postretirement benefits charged to KCP&L are accrued during an employee's years of service and recovered through rates. The Company funds the portion of net periodic postretirement benefit costs that are tax deductible. For post-retirement health care plans sponsored by Great Plains Energy, contributions and expense are allocated to KCP&L and Services based upon the number of plan participants.

In December 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Medicare Act) was signed into law. The Medicare Act, among other things, provides a federal subsidy to sponsors of retiree health care benefit plans. In 2004, the Company adopted FASB Staff Position No. FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003." The 2004 actuarial measurements include the effects of the Medicare Act. The Medicare Act did not materially impact plan obligations and it is not expected to materially impact future health care costs and participation rates.

The following pension benefits tables provide information relating to the funded status of all defined benefit pension plans on an aggregate basis. The plan measurement date for the majority of plans is September 30. In 2004, contributions of $20.7 million were made to the pension plans after the measurement date and in 2003, contributions of $32.0 million and $4.8 million were made to the pension and postretirement benefit plans, respectively, after the measurement date. Net periodic benefit costs reflect total plan benefit costs prior to the effects of capitalization and sharing with joint-owners of power plants.

	Pension Benefits		Other Benefits	
	2004	2003	2004	2003
	(thousands)			
Change in projected benefit obligation (PBO)				
PBO at beginning of year	$ 501,497	$ 450,800	$ 52,119	$ 48,936
Service cost	16,695	14,969	948	851
Interest cost	30,137	29,892	3,094	3,210
Contribution by participants	-	-	1,082	858
Amendments	-	34	-	230
Actuarial loss (gain)	25,117	42,496	(3,193)	2,176
Benefits paid	(54,702)	(36,122)	(4,331)	(3,655)
Benefits paid by Company	(348)	(572)	(585)	(487)
Settlements	(2,660)	-	-	-
PBO at end of plan year	$ 515,736	$ 501,497	$ 49,134	$ 52,119
Change in plan assets				
Fair value of plan assets at beginning of year	$ 340,986	$ 324,169	$ 8,353	$ 11,054
Actual return on plan assets	33,893	43,663	287	122
Contributions by employer and participants	50,345	9,276	10,424	970
Benefits paid	(54,702)	(36,122)	(4,331)	(3,793)
Fair value of plan assets at end of plan year	$ 370,522	$ 340,986	$ 14,733	$ 8,353
Prepaid (accrued) benefit cost				
Funded status	$(145,214)	$(160,511)	$(34,401)	$(43,766)
Unrecognized actuarial loss	195,978	182,555	10,467	13,984
Unrecognized prior service cost	36,271	40,556	1,045	1,282
Unrecognized transition obligation	398	455	9,395	10,570
Net prepaid (accrued) benefit cost	$ 87,433	$ 63,055	$(13,494)	$(17,930)
Amounts recognized in the consolidated balance sheets				
Prepaid benefit cost	$ 89,229	$ 80,881	$ -	$ -
Accrued benefit cost	(1,796)	(17,826)	(13,494)	(17,930)
Minimum pension liability adjustment	(84,245)	(78,435)	-	-
Intangible asset	15,613	17,426	-	-
Accumulated other comprehensive income	68,632	61,009	-	-
Net amount recognized in balance sheets	87,433	63,055	(13,494)	(17,930)
Contributions and changes after measurement date	20,740	34,139	-	4,790
Net amount recognized at December 31	$ 108,173	$ 97,194	$(13,494)	$(13,140)

	Pension Benefits			Other Benefits		
	2004	2003	2002	2004	2003	2002
Components of net periodic benefit cost			(thousands)			
Service cost	$ 16,695	$ 14,969	$ 13,360	$ 948	$ 851	$ 757
Interest cost	30,137	29,892	30,272	3,094	3,210	2,951
Expected return on plan assets	(31,701)	(27,702)	(34,144)	(669)	(572)	(503)
Amortization of prior service cost	4,285	4,286	4,313	237	216	194
Recognized net actuarial loss (gain)	7,746	1,377	(7,237)	737	574	100
Transition obligation	57	57	(742)	1,175	1,175	1,174
Amendment	-	-	-	-	110	-
Net settlements	1,798	-	284	-	-	-
Net periodic benefit cost	$ 29,017	$ 22,879	$ 6,106	$ 5,522	$ 5,564	$ 4,673

The accumulated benefit obligation (ABO) for all defined benefit pension plans was $445.4 million and $429.9 million at December 31, 2004 and 2003, respectively. The projected benefit obligation, accumulated benefit obligation and the fair value of plan assets at plan year-end are aggregated by funded and underfunded plans in the following table.

	2004	2003
Pension plans with the ABO in excess of plan assets	(thousands)	
Projected benefit obligation	$ 309,799	$ 297,392
Accumulated benefit obligation	266,081	252,209
Fair value of plan assets	179,980	156,389
Pension plans with plan assets in excess of the ABO		
Projected benefit obligation	$ 205,937	$ 204,105
Accumulated benefit obligation	179,327	177,725
Fair value of plan assets	190,542	184,597

Pension plan assets are managed in accordance with "prudent investor" guidelines contained in the ERISA requirements. The investment strategy supports the objective of the fund, which is to earn the highest possible return on plan assets within a reasonable and prudent level of risk. Investments are diversified across classes and within each class to minimize risks. At December 31, 2004 and 2003, the fair value of plan assets was $370.5 million, not including a $20.7 million contribution made after the plan year-end, and $341.0 million, not including a $32.0 million subsequent contribution, respectively. The asset allocation for the Company's pension plans at the end of 2004 and 2003, and the target allocation for 2005 are reported in the following table. The portfolio is rebalanced when the targets are exceeded.

Asset Category	Target Allocation	Plan Assets at December 31 2004	2003
Equity securities	59%	59%	62%
Debt securities	30%	31%	34%
Real estate	6%	8%	4%
Other	5%	2%	0%
Total	100%	100%	100%

The expected long-term rate of return on plan assets is based on historical and projected rates of return for current and planned asset classes in the plan's investment portfolio. Assumed projected rates of return for each asset class were selected after analyzing historical experience and future expectations of the returns of various asset classes. Based on the target asset allocation for each asset class, the overall expected rate of return for the portfolio was developed and adjusted for the effect of projected benefits paid from plan assets and future plan contributions.

The following tables provide the weighted-average assumptions used to determine benefit obligations and net costs.

Weighted average assumptions used to determine the benefit obligation at plan year-end	**Pension Benefits 2004**	**Pension Benefits 2003**	**Other Benefits 2004**	**Other Benefits 2003**
Discount rate	5.82%	6.00%	5.82%	6.00%
Rate of compensation increase	3.06%	3.30%	3.05%	3.25%

Weighted average assumptions used to determine net costs for years ended at December 31	**Pension Benefits 2004**	**Pension Benefits 2003**	**Other Benefits 2004**	**Other Benefits 2003**
Discount rate	6.00%	6.75%	6.00%	6.75%
Expected long-term return on plan assets	9.00%	9.00%	9.00%	9.00%
Rate of compensation increase	3.30%	4.10%	3.25%	4.00%

Primarily as a result of lower discount rates and historical losses in the market value of plan assets, the Company recorded a minimum pension liability offset by an intangible asset and OCI. The amounts recognized in Great Plains Energy's and consolidated KCP&L's balance sheets related to the minimum pension liability are detailed in the following table.

	Great Plains Energy December 31		**Consolidated KCP&L December 31**	
	2004	**2003**	**2004**	**2003**
		(millions)		
Additional minimum pension liability	$ 84.2	$ 78.4	$ 79.8	$ 74.4
Intangible asset	15.6	17.4	14.6	16.5
Deferred taxes	26.3	23.8	25.0	22.6
OCI, net of tax	42.3	37.2	40.2	35.3

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. The health care plan requires retirees to share in the cost when premiums exceed a certain amount. The following table provides information on the assumed health care rate trends.

Assumed Health Care Cost Trends at December 31	**2004**	**2003**
Health care cost trend rate assumed for next year	10%	9%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	5%	5%
Year that the rate reaches the ultimate trend rate	2010	2008

The effects of a one-percentage point change in the medical cost trend rates, holding all other assumptions constant, as of December 31, 2004, are detailed in the following table.

	Increase	Decrease
	(thousands)	
Effect on total service and interest component	$ 73	$ (62)
Effect on postretirement benefit obligation	$ 732	$ (647)

The Company expects to contribute $4.7 million to its pension plans and $4.3 million to its other postretirement benefit plans in 2005. The Company's funding policy is to contribute amounts sufficient to meet the minimum funding requirements of employee benefit and tax regulations plus additional amounts as deemed fiscally appropriate, therefore actual contributions may differ from expected contributions.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid through fiscal 2014.

	Pension Benefits	Other Benefits
	(thousands)	
2005	$ 32,934	$ 5,479
2006	35,827	5,984
2007	36,532	6,739
2008	37,262	7,497
2009	39,358	8,205
2010-2014	238,915	51,370

Employee Savings Plans

Great Plains Energy has defined contribution savings plans that cover substantially all employees. The Company matches employee contributions, subject to limits. The annual cost of the plans was $4.3 million in 2004 and $4.1 million in 2003 and 2002.

Strategic Energy Phantom Stock Plan

Strategic Energy had a phantom stock plan that provided incentive in the form of deferred compensation based upon the award of performance units, the value of which was related to the increase in profitability of Strategic Energy. The plan was terminated and an insignificant amount of costs were recorded in 2004. Strategic Energy's annual cost for the plan was $4.6 million and $5.9 million in 2003 and 2002, respectively.

10. EQUITY COMPENSATION

The Company's Long-Term Incentive Plan is an equity compensation plan approved by its shareholders. The Long-Term Incentive Plan permits the grant of restricted stock, stock options, limited stock appreciation rights and performance shares to officers and other employees of the Company and its subsidiaries. The maximum number of shares of Great Plains Energy common stock that can be issued under the plan is 3.0 million. At December 31, 2004, 2.2 million shares remained available for future issuance.

Stock Options Granted 1995

The exercise price of stock options granted equaled the market price of the Company's common stock on the grant date. An amount equal to the quarterly dividends paid on Great Plains Energy common stock shares (dividend equivalents) accrues on the options for the benefit of option holders. The option holders are entitled to stock for their accumulated dividend equivalents only if the options are exercised when the market price is above the exercise price. At December 31, 2004, the market price of Great Plains Energy common stock was $30.28, which exceeded the grant price for all such options still outstanding. Unexercised options expire ten years after the grant date. For options outstanding at December 31, 2004, the grant price was $23.0625 and the remaining contractual life was 0.4 years.

Prior to the adoption of SFAS No. 123 on January 1, 2003, Great Plains Energy followed Accounting Principles Board (APB) Opinion 25, "Accounting for Stock Issued to Employees" and related interpretations in accounting for these options. Great Plains Energy recognized annual compensation expense equal to accumulated and reinvested dividends plus the impact of the change in stock price since the grant date. Great Plains Energy recognized compensation expense of $0.1 million in 2002. These options were fully vested prior to the adoption of SFAS No. 123; therefore, no compensation expense was recognized in 2003 or 2004.

Stock Options Granted 2001 – 2003

Stock options were granted under the plan at the fair market value of the shares on the grant date. The options vest three years after the grant date and expire in ten years if not exercised. Exercise prices range from $24.90 to $27.73 and the weighted-average remaining contractual life at December 31, 2004 was 6.9 years.

In accordance with the provisions of SFAS No. 123, the Company recognized an insignificant amount of compensation expense in 2004 and 2003. Under the provisions of APB Opinion 25, no compensation expense was recognized in 2002 because the option exercise price was equal to the market price of the underlying stock on the date of grant.

The fair value for the stock options granted in 2001 – 2003 was estimated at the date of grant using the Black-Scholes option-pricing model. The option valuation model requires the input of highly subjective assumptions, primarily stock price volatility, changes in which can materially affect the fair value estimate. The weighted-average assumptions used are detailed in the following table.

	2003	2002	2001
Risk-free interest rate	4.77 %	4.57 %	5.53 %
Dividend yield	6.88 %	7.68 %	6.37 %
Stock volatility	22.650 %	27.503 %	25.879 %
Expected option life (in years)	10	10	10

All stock option activity for the last three years is summarized in the following table.

	2004		2003		2002	
	Shares	Price*	Shares	Price*	Shares	Price*
Outstanding at January 1	241,898	$ 25.41	397,000	$ 25.21	250,375	$ 25.14
Granted	-	-	27,898	27.73	181,000	24.90
Exercised	(26,000)	24.79	(16,000)	26.19	(34,375)	23.00
Forfeited	(19,925)	25.50	(167,000)	25.26	-	-
Outstanding at December 31	195,973	$ 25.48	241,898	$ 25.41	397,000	$ 25.21
Exercisable as of December 31	75,000	$ 25.43	7,000	$ 21.67	23,000	$ 24.81

* weighted-average price

Performance Shares

The number of performance shares granted may increase or decrease depending on company performance goals as compared to a peer group of utilities, over a three-year vesting period. The issuance of performance shares is contingent upon achievement of these goals. Performance shares have a value equal to the fair market value of the shares on the grant date with accruing dividends. During 2004, 1,431 of the 20,744 performance shares granted in 2003 were forfeited, and at December 31, 2004, 19,313 shares were outstanding. No additional shares were granted in 2004. In accordance with the provisions of SFAS No. 123, compensation expense and accrued dividends are recognized over the vesting period based on the Company's estimate of the number of shares to be issued. The Company recognized an insignificant amount of compensation expense in 2004 and $0.4 million in 2003.

During 2003, all 144,500 performance shares granted in 2001 were canceled. No compensation expense had been recorded related to these performance shares.

Restricted Stock

Restricted stock cannot be sold or otherwise transferred by the recipient prior to vesting and has a value equal to the fair market value of the shares on the grant date. Restricted stock granted in 2004 and 2003 totaled 13,333 and 120,196, respectively. Restricted stock shares issued in 2003 totaling 57,315 vested in 2003 and were issued out of treasury stock; however, 54,436 of these shares were restricted as to transfer until December 31, 2004, but were considered vested under SFAS No. 123 because the employee's right to retain the shares of stock was not contingent upon remaining in the service of the Company and was not contingent upon achievement of performance conditions. The remaining restricted stock shares issued in 2004 and 2003, totaling 76,214, vest on a graded schedule over a three-year period with accruing reinvested dividends. The Company recognized compensation expense of $0.6 million and $1.8 million in 2004 and 2003, respectively.

11. INCOME TAXES

Components of income tax expense (benefit) are detailed in the following tables.

Great Plains Energy	2004	2003	2002
Current income taxes		(thousands)	
Federal	$ 19,898	$ 12,024	$ 27,505
State	13,255	8,896	9,369
Total	33,153	20,920	36,874
Deferred income taxes			
Federal	45,811	23,299	13,915
State	(15,492)	3,497	1,679
Total	30,319	26,796	15,594
Investment tax credit amortization	(3,984)	(3,994)	(4,183)
Total income tax expense	59,488	43,722	48,285
Less: taxes on discontinued operations (Notes 6 and 7)			
Current tax benefit	(4,996)	(31,167)	(6,648)
Deferred tax (benefit) expense	10,033	(3,676)	3,585
Income taxes on continuing operations	$ 54,451	$ 78,565	$ 51,348

Consolidated KCP&L	2004	2003	2002
Current income taxes		(thousands)	
Federal	$ 39,232	$ 26,063	$ 47,027
State	6,654	5,688	8,668
Total	45,886	31,751	55,695
Deferred income taxes			
Federal	22,226	37,140	9,391
State	(11,365)	6,883	1,964
Total	10,861	44,023	11,355
Investment tax credit amortization	(3,984)	(3,994)	(4,183)
Total income tax expense	52,763	71,780	62,867
Less: taxes on discontinued operations (Notes 6 and 7)			
Current tax (benefit) expense	-	(21,530)	10
Deferred tax expense	-	9,738	-
Income taxes on continuing operations	$ 52,763	$ 83,572	$ 62,857

Effective Income Tax Rates

The effective income tax rates reflected in the financial statements and the reasons for their differences from the statutory federal rates are in the following tables.

Great Plains Energy	2004	2003	2002
Federal statutory income tax rate	35.0 %	35.0 %	35.0 %
Differences between book and tax depreciation not normalized	0.6	2.1	1.9
Amortization of investment tax credits	(1.7)	(2.1)	(2.4)
Federal income tax credits	(5.3)	(7.7)	(11.3)
State income taxes	3.3	4.8	4.1
State effective rate change on deferred taxes	(3.6)	-	-
Valuation allowance	0.2	(8.4)	-
RSAE [a]	-	(1.9)	1.4
Other	(3.5)	1.5	(1.0)
Effective income tax rate	25.0 %	23.3 %	27.7 %

Consolidated KCP&L	2004	2003	2002
Federal statutory income tax rate	35.0 %	35.0 %	35.0 %
Differences between book and tax depreciation not normalized	0.7	2.1	2.1
Amortization of investment tax credits	(2.0)	(2.1)	(2.6)
State income taxes	3.4	4.3	4.4
State effective rate change on deferred taxes	(4.4)	-	-
Allocation of parent company tax benefits	(3.0)	-	-
RSAE [a]	-	(1.9)	1.5
Other	(2.7)	0.6	(0.8)
Effective income tax rate	27.0 %	38.0 %	39.6 %

[a] Amounts reflect the tax effect of operations in 2002 and the effect of the disposition in 2003.

Great Plains Energy and consolidated KCP&L's income tax expense decreased by $10.8 million and $10.1 million, respectively, due to the favorable impact of state tax planning on the companies' composite tax rates. SFAS No. 109, "Accounting for Income Taxes" requires the companies to adjust deferred tax balances to reflect tax rates that are anticipated to be in effect when the differences reverse. The largest component of the companies' decreases in income taxes was the result of adjusting KCP&L's deferred tax balance to its lower composite tax rate. The impact of the composite tax rate reductions on KCP&L's deferred tax balances resulted in an $8.6 million tax benefit for both the Company and consolidated KCP&L. The change in the deferred tax balances reduced the Company's and consolidated KCP&L's 2004 effective tax rates by 3.6% and 4.4%, respectively.

Deferred Income Taxes

The tax effects of major temporary differences resulting in deferred tax assets and liabilities in the balance sheets are in the following table.

	Great Plains Energy		Consolidated KCP&L	
December 31	**2004**	**2003**	**2004**	**2003**
	(thousands)			
Plant related	$ 556,543	$ 543,840	$ 556,543	$ 543,840
Future income taxes	81,000	89,000	81,000	89,000
Pension and postretirement benefits	9,047	6,838	9,239	7,768
Tax credit carryforwards	(23,661)	(22,393)	-	-
Gas properties related	3,356	(6,640)	-	-
Nuclear fuel outage	(5,061)	(686)	(5,061)	(686)
Alternative minimum tax credit carryforward	(4,093)	(4,093)	-	-
State net operating loss carryforward	(476)	-	-	-
Other	1,964	(7,252)	(484)	1,065
Net deferred tax liability before valuation allowance	618,619	598,614	641,237	640,987
Valuation allowance	476	-	-	-
Less deferred taxes in discontinued operations (Notes 6 and 7)	-	10,033	-	-
Net deferred tax liability	$ 619,095	$ 608,647	$ 641,237	$ 640,987

The net deferred income tax liability is detailed in the following table.

	Great Plains Energy		Consolidated KCP&L	
December 31	**2004**	**2003**	**2004**	**2003**
	(thousands)			
Gross deferred income tax assets	$ (144,324)	$ (131,968)	$ (120,739)	$ (99,936)
Gross deferred income tax liabilities	763,419	740,615	761,976	740,923
Net deferred income tax liability	$ 619,095	$ 608,647	$ 641,237	$ 640,987

Tax Credit Carryforwards

At December 31, 2004, the Company had $7.3 million and $16.4 million of federal and Missouri state income tax credit carryforwards, respectively. These credits relate primarily to the Company's low-income housing investment portfolio, and the carryforwards expire in years 2006 to 2024. Management believes the credits will be fully utilized within the carryforward period.

Net Operating Loss Carryforwards

At December 31, 2004, KLT Inc. and subsidiaries had Kansas state net operating loss carryforwards of $10.0 million primarily resulting from losses associated with DTI. KLT Inc. and subsidiaries moved its corporate headquarters to Missouri in 2003, and as a result, will not have sufficient presence in Kansas to utilize the losses. The Kansas state net operating loss carryforwards expire in years 2011 to 2012.

In 2004, management determined that the loss carryforwards will more likely than not expire unutilized and has provided a valuation allowance against the entire deferred tax benefit.

Reserve for Contingent Tax Liabilities

Management evaluates and records contingent tax liabilities based on the probability of ultimately sustaining the tax deductions or income positions. Management assesses the probabilities of successfully defending the tax deductions or income positions based upon statutory, judicial or administrative authority.

At December 31, 2004 and 2003, the Company had $13.4 million and $16.8 million, respectively, of liabilities for contingencies related to tax deductions or income positions taken on the Company's tax returns. Consolidated KCP&L had liabilities of $3.7 million and $6.4 million at December 31, 2004 and 2003, respectively. Management believes the tax deductions or income positions are properly treated on such tax returns, but has recorded reserves based upon its assessment of the probabilities that certain deductions or income positions may not be sustained when the returns are audited. The tax returns containing these tax deductions or income positions are currently under audit or will likely be audited. The timing of the resolution of these audits is uncertain. If the positions are ultimately sustained, the Company will reverse these tax provisions to income. If the positions are not ultimately sustained, the Company may be required to make cash payments plus interest and/or utilize the Company's federal and state credit carryforwards.

Internal Revenue Service Settlement

In November 2002, KCP&L accepted a settlement offer related to the proposed disallowance of interest deductions on corporate-owned life insurance (COLI) loans. The offer allowed 20% of the interest originally deducted and taxed only 20% of the gain on surrender of the COLI policies. KCP&L surrendered the policies in February 2003. KCP&L paid $1.3 million to the IRS in 2003 to satisfy the liability associated with the surrender. In December 2004, KCP&L settled the 1995-1999 IRS audit and paid tax of $7.3 million and interest of $4.2 million related to the disallowed COLI interest deduction. KCP&L accrued for these payments in 2000.

In addition to COLI, as part of the settlement of the 1995-1999 IRS audit, consolidated KCP&L agreed to additional tax of $6.9 million and interest of $5.9 million related primarily to timing differences. This settlement did not have a significant impact on consolidated KCP&L's net income because the liability had been previously recorded in the liabilities for tax contingencies or had offsetting impacts on deferred taxes.

12. RELATED PARTY TRANSACTIONS AND RELATIONSHIPS

In May 2004, Great Plains Energy, through IEC, completed its purchase from SE Holdings, L.L.C. (SE Holdings) of an additional 11.45% indirect interest in Strategic Energy. The purchase increased Great Plains Energy's indirect ownership of Strategic Energy to just under 100%. See Note 8 for additional information regarding the purchase transaction. Richard Zomnir, who resigned as Chief Executive Officer of Strategic Energy in November 2004, and certain other current and former employees of Strategic Energy held direct or indirect interests in SE Holdings. Mr. Zomnir has disclosed that he held an approximate 25% interest in SE Holdings. In connection with the transaction, Mr. Zomnir and other direct and indirect owners of SE Holdings entered into an agreement with IEC and Strategic Energy, providing for certain indemnification rights related to the litigation described in Note 15.

SE Holdings remains a member of Custom Energy Holdings, L.L.C. (Custom Energy Holdings) and is represented on the Management Committees of Custom Energy Holdings and Strategic Energy. Custom Energy Holdings' business and affairs are controlled and managed by a three member Management Committee composed of one representative designated by KLT Energy Services Inc.

(KLT Energy Services), one representative designated by IEC, and one representative designated by SE Holdings. Certain actions (including amendment of Custom Energy Holdings' operating agreement, approval of actions in contravention of the operating agreement, approval of a dissolution of Custom Energy Holdings, additional capital contributions and assumption of recourse indebtedness) require the unanimous consent of all the members of Custom Energy Holdings.

Strategic Energy's business and affairs are controlled and managed by a four member Management Committee composed of two representatives designated by KLT Energy Services, one representative designated by IEC and one representative designated by SE Holdings. Certain actions (including amendment of Strategic Energy's operating agreement, approval of actions in contravention of the operating agreement, approval of transactions between Strategic Energy and affiliates of its members, approval of a dissolution of Strategic Energy, and assumption of recourse indebtedness) require the unanimous consent of all the Management Committee members.

Pursuant to a service agreement approved by the SEC under the 35 Act, consolidated KCP&L began receiving various support and administrative services from Services. These services are billed to consolidated KCP&L at cost based on payroll and other expenses incurred by Services for the benefit of consolidated KCP&L. These costs totaled $62.7 million and $45.2 million for 2004 and 2003, respectively, and consisted primarily of employee compensation, benefits and fees associated with various professional services. At December 31, 2004 and 2003, consolidated KCP&L had a net intercompany payable to Services of $9.2 million and $10.9 million, respectively.

13. COMMITMENTS AND CONTINGENCIES

Nuclear Liability and Insurance

The owners of Wolf Creek, a nuclear generating station, (Owners) 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 of, as defined by the Terrorism Risk Insurance Act, of terrorism-related losses, including replacement power costs. An industry aggregate limit of $0.3 billion 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 $3.2 billion plus any reinsurance recoverable by Nuclear Electric Insurance Limited (NEIL), the Owners 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.

Liability Insurance

Pursuant to the Price-Anderson Act, the Owners are required to insure against public liability claims resulting from nuclear incidents to the full limit of public liability, which is currently $10.8 billion. This limit of liability consists of the maximum available commercial insurance of $0.3 billion, and the remaining $10.5 billion is provided through an industry-wide retrospective assessment program mandated by the NRC. Under this retrospective assessment program, the Owners can be assessed up to $100.6 million ($47.3 million, KCP&L's 47% share) per incident at any commercial reactor in the country, payable at no more than $10 million ($4.7 million, KCP&L's 47% share) per incident per year. This assessment is subject to an inflation adjustment based on the Consumer Price Index and applicable premium taxes. This assessment also applies in excess of our worker radiation claims insurance. In addition, the U.S. Congress could impose additional revenue-raising measures to pay claims. If the $10.8 billion liability limitation is insufficient, management believes the U.S. Congress will consider taking whatever action is necessary to compensate the public for valid claims.

The Price-Anderson Act expired in August 2002 and was extended until December 31, 2003 for Licensees. Licensees such as Wolf Creek continue to be grandfathered under the Act. A current version of a comprehensive energy bill pending before Congress contains provisions that would amend the Price-Anderson Act addressing public liability from nuclear energy hazards in ways that would increase the annual limit on retrospective assessments from $10 million to $15 million per reactor per incident.

Property, Decontamination, Premature Decommissioning and Extra Expense Insurance
The Owners carry decontamination liability, premature decommissioning liability and property damage insurance for Wolf Creek totaling approximately $2.8 billion ($1.3 billion, KCP&L's 47% share). NEIL provides this insurance.

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. KCP&L's share of any remaining proceeds can be used for further decontamination, property damage restoration and premature decommissioning costs. Premature decommissioning coverage applies only if an accident at Wolf Creek exceeds $500 million in property damage and decontamination expenses, and only after trust funds have been exhausted.

Accidental Nuclear Outage Insurance
The Owners also carry additional insurance from NEIL to cover costs of replacement power and other extra expenses incurred in the event of a prolonged outage resulting from accidental property damage at Wolf Creek.

Under all NEIL policies, the Owners are subject to retrospective assessments if NEIL losses, for each policy year, exceed the accumulated funds available to the insurer under that policy. The estimated maximum amount of retrospective assessments under the current policies could total about $26.0 million ($12.2 million, KCP&L's 47% share) per policy year.

In the event of a catastrophic loss at Wolf Creek, the insurance coverage may not be adequate to cover property damage and extra expenses incurred. Uninsured losses, to the extent not recovered through rates, would be assumed by KCP&L and could have a material, adverse effect on its financial condition, results of operations and cash flows.

Low-Level Waste
The Low-Level Radioactive Waste Policy Amendments Act of 1985 mandated that the various states, individually or through interstate compacts, develop alternative low-level radioactive waste disposal facilities. The states of Kansas, Nebraska, Arkansas, Louisiana and Oklahoma formed the Central Interstate Low-Level Radioactive Waste Compact (Compact) and selected a site in northern Nebraska to locate a disposal facility. WCNOC and the owners of the other five nuclear units in the Compact provided most of the pre-construction financing for this project. KCP&L's net investment in the Compact was $7.4 million at December 31, 2004, and December 31, 2003.

On December 18, 1998, the application for a license to construct this project was denied. After the license denial, WCNOC, the Compact Commission (Commission) and others filed a lawsuit in federal court contending Nebraska officials acted in bad faith while handling the license application. In September 2002, the U.S. District Court Judge presiding over the lawsuit issued his decision in the case finding that the State of Nebraska acted in bad faith in processing the license application for a low-level radioactive waste disposal site in Nebraska and rendered a judgment on behalf of the Commission in the amount of $151.4 million against the state. After the U.S. Court of Appeals affirmed the decision, Nebraska and the Commission settled the case by Nebraska agreeing to pay the Commission either a one-time amount of $140.5 million or four annual installments of $38.5 million each beginning on August 1, 2005. All related litigation and appeals have been dismissed. Upon final payment, Nebraska will be relieved of its responsibility to host a disposal facility. The Commission has begun seeking alternative long-term waste disposal capability elsewhere. WCNOC intends to pursue with the Commission the possibility of recovering from the settlement proceeds some of WCNOC's contributions to the Nebraska facility's pre-licensing effort. Based on the contribution of the respective utilities in relation to the total settlement amount, management believes the settlement proceeds would be sufficient to recover KCP&L's $7.4 million net investment in the Compact.

Wolf Creek continues to dispose of its low-level radioactive waste at the reopened disposal facility at Barnwell, South Carolina. South Carolina intends to gradually decrease the amount of waste it allows from outside its compact until around 2008 when it intends to no longer accept waste from generators outside its compact. Wolf Creek remains able to dispose of some of its radioactive waste at a facility in Utah. Although management is unable to predict when a permanent disposal facility for Wolf Creek low-level radioactive waste might become available, this issue is not expected to affect continued operation of Wolf Creek.

Environmental Matters
The Company is subject to regulation by federal, state and local authorities with regard to air and other environmental matters primarily through KCP&L's operations. The generation, transmission and distribution of electricity produces and requires disposal of certain hazardous products that are subject to these laws and regulations. In addition to imposing continuing compliance obligations, these laws and regulations authorize the imposition of substantial penalties for noncompliance, including fines, injunctive relief and other sanctions. Failure to comply with these laws and regulations could have a material adverse effect on consolidated KCP&L and Great Plains Energy.

KCP&L operates in an environmentally responsible manner and seeks to use current technology to avoid and treat contamination. KCP&L regularly conducts environmental audits designed to ensure compliance with governmental regulations and to detect contamination. Governmental bodies, however, may impose additional or more restrictive environmental regulations that could require substantial changes to operations or facilities at a significant cost. At December 31, 2004 and 2003, KCP&L had $0.3 million and $1.8 million, respectively, accrued for environmental remediation expenses. The remaining accrual covers water monitoring at one site. The amounts accrued were established on an undiscounted basis and KCP&L does not currently have an estimated time frame over which the accrued amounts may be paid out.

On April 15, 2004, the EPA issued to KCP&L a notice of violation of Hawthorn No. 5 permit limits on sulfur dioxide (SO_2) emissions. SO_2 emissions from Hawthorn No. 5 exceeded the applicable thirty-day rolling average emission limit on certain days in the third and fourth quarters of 2003 and also exceeded the applicable 24-hour emission limit on one day in the fourth quarter of 2003. These exceedances occurred while the unit was operating in compliance with an exception protocol that had been accepted by the issuer of the air permit. The equipment issues that caused these violations have been addressed by KCP&L. In September 2004, KCP&L finalized a consent order with the EPA, agreeing to pay a civil penalty and fund certain Kansas City metro environmental projects at an aggregate cost of $0.4 million.

Discussed below are issues that may require material expenditures to comply with environmental laws and regulations. KCP&L's expectation is that any such expenditures will be recovered through rates.

Clean Air Legislation

Congress is currently debating numerous bills that could make significant changes to the Clean Air Act Amendments of 1990 (Clean Air Act) including potential establishment of nationwide limits on power plant emissions for several specific pollutants. Some of these bills address oxides of sulfur and nitrogen (SO_x and NO_x), mercury and carbon dioxide (CO_2), while other bills address SO_x, NO_x and mercury, and some legislative bills address CO_2 by itself. There are various compliance dates and compliance limits stipulated in the numerous legislative bills being debated. These bills have the potential for a significant financial impact on KCP&L through the installation of new pollution control equipment to achieve compliance if new nationwide limits are enacted. The financial consequences to KCP&L cannot be accurately determined until the final legislation is passed. However, KCP&L would seek recovery of capital costs and expenses for such compliance through rates. KCP&L will continue to monitor the progress of these bills.

EPA Phase II NO_x SIP Call

On April 1, 2004, the Environmental Protection Agency (EPA) issued final Phase II NO_x State Implementation Plan (SIP) Call regulation, which specifically excludes coal-fired power plants in the western part of Missouri, including all of KCP&L's Missouri coal-fired plants, from the NO_x SIP Call. The final Phase II NO_x SIP Call was contained in the April 21, 2004, Federal Register with an effective date of June 7, 2004. This action completes the EPA's response to several decisions from the U.S. Court of Appeals for the District of Columbia.

NO_x and SO_2 Regulations-Proposed Clean Air Interstate Rule

The EPA published a proposed regulation in the January 30, 2004, Federal Register titled the Interstate Air Quality Rule, which addresses SO_2 and NO_x emissions. This title was subsequently changed to the Clean Air Interstate Rule (CAIR). A supplemental proposal for the CAIR was published in the June 10, 2004, Federal Register. The proposed CAIR is designed to reduce NO_x and SO_2 emissions 65% and 70%, respectively, below current levels in a two-phased program between 2010 and 2015.

If coal-fired plants in Missouri and Kansas are required to implement reductions under the proposed CAIR, KCP&L would need to incur significant capital costs, purchase power or purchase emission allowances. Preliminary analysis of the proposed regulation indicates that selective catalytic reduction technology for NO_x control and scrubbers for SO_2 control may be required for some of the KCP&L units. Currently, KCP&L estimates that additional capital expenditures could range from $385 million to $555 million. The timing of the installation of such control equipment is uncertain pending the final regulation being issued. The final regulation is expected to contain specific compliance dates and compliance levels, final determination of whether Kansas and/or Missouri are included (as they are in the proposed rules), as well as the applicability of accumulated SO_2 allowances for future compliance. KCP&L is currently allocated approximately 50,000 tons of SO_2 allowances per year to support its emissions of approximately 50,000 tons per year. KCP&L has accumulated over 190,000 tons of allocated SO_2 allowances; however, the disposition of such credits is subject to regulatory approvals from both Kansas and Missouri. KCP&L continues to refine these preliminary estimates and explore alternatives. The ultimate cost of these regulations, if any, could be significantly different from the amounts estimated above. The CAIR is scheduled to be finalized in March 2005. As discussed below, certain of the control technology for SO_2 and NO_x will also aid in the control of mercury. If mercury controls, as discussed below, are required to be implemented prior to the CAIR, the above estimates could be reduced by $100 million to $144 million.

In the May 5, 2004, Federal Register, the EPA published proposed regulations on best available retrofit technology (BART) that would amend its July 1999 regional haze regulations regarding emission controls for industrial facilities emitting air pollutants that reduce visibility. The BART requirement would direct state air quality agencies to identify whether emissions from sources subject to BART are below limits set by the state, or whether retrofit measures are needed to reduce the emissions below those limits. If the proposed BART regulations are adopted, they will apply to KCP&L units Montrose No. 3, LaCygne No. 1, LaCygne No. 2 and Iatan. Based on the results of the state air quality studies, KCP&L could be required to achieve compliance by making capital expenditures that would be similar to those required for the proposed CAIR. The EPA is scheduled to adopt final regulations by April 15, 2005; however, if the proposed CAIR is adopted, management believes the EPA will reevaluate the need for the proposed BART regulation.

Mercury Emissions

In July 2000, the National Research Council published its findings of a study under the Clean Air Act, which stated that power plants that burn fossil fuels, particularly coal, generate the greatest amount of mercury emissions from man-made sources. As a result, in the January 30, 2004, and March 16, 2004, Federal Registers, the EPA published proposed regulations for controlling mercury emissions from coal-fired power plants that contained three options. Two of the options, the EPA's preferred approaches, call for regulating mercury via emission trading regimes under section 111 or section 112 of the Clean Air Act (cap and trade options), and the third option would require utilities to install controls known as maximum achievable control technology (MACT). The EPA is scheduled to issue final rules by March 2005.

Under either of the cap and trade options, both of which would become applicable in 2010, the EPA would establish a mechanism by which mercury emissions from new and existing coal-fired plants would be capped at specified, nationwide levels. A first phase cap of 34 tons would become effective on January 1, 2010, and a second phase cap of 15 tons would become effective on January 1, 2018. Facilities would demonstrate compliance with the standard by holding one allowance for each ounce of mercury emitted in any given year and allowances would be readily transferable among all regulated facilities nationwide. Under the cap and trade options, KCP&L would be able to purchase mercury allowances that would be available nationwide or elect to install pollution control equipment to achieve compliance. While it is expected that mercury allowances would be available in sufficient quantities for purchase in the 2010-2018 timeframe, the significant reduction in the nationwide cap in 2018 may hamper KCP&L's ability to obtain reasonably priced allowances beyond 2018. Therefore, capital expenditures may be required in the 2016-2018 timeframe to install mercury pollution control equipment.

Under the MACT option, KCP&L could incur capital expenses prior to the 2007-2008 timeframe when the regulation would be applicable. This option would require compliance on a facility basis and therefore the option of trading nationwide mercury allowances would not be available. The EPA stated in the preamble that there are no adequately demonstrated control technologies specifically designed to reduce mercury emissions from coal-fired plants. However, the EPA also stated it is confident such technologies will be commercially available by 2007. There is currently considerable debate at the EPA and within the utility industry whether the installation of pollution control equipment for the control of NO_x and SO_2 under the CAIR might simultaneously remove mercury to the specified MACT regulatory levels, which is referred to as the co-benefit approach. If this approach is correct, and if the CAIR became final and all of KCP&L's units were subject to the final regulation, KCP&L would not be required to install additional mercury control equipment to achieve compliance with this regulation. However, if the co-benefit approach is not correct, or if KCP&L units located in Missouri and/or Kansas were not included in the final CAIR regulation, KCP&L would be required to install mercury control equipment prior to 2007. If KCP&L were required to install mercury control equipment on all of its coal-fired plants, it is anticipated that activated carbon injection or comparable technology in conjunction with a baghouse would need to be installed at a projected cost to KCP&L ranging from $170 million to $245 million.

KCP&L is a participant in the DOE project at the Sunflower Electric Holcomb plant to investigate control technology options for mercury removal from coal-fired plants burning sub bituminous coal.

Carbon Dioxide

At a December 1997 meeting in Kyoto, Japan, delegates from 167 nations, including the U.S., agreed to a treaty (Kyoto Protocol) that would require a 7% reduction in U.S. CO_2 emissions below 1990 levels, a nearly 30% cut from current levels. On March 28, 2001, the Bush administration announced it will not negotiate implementation of the Kyoto Protocol and it will not send the Kyoto Protocol to the U.S. Senate for ratification.

There are several bills being debated in the U.S. Congress that address the CO_2 issue, including establishing a nationwide cap on CO_2 levels. There are various compliance dates and nationwide caps stipulated in the numerous legislative bills being debated. These bills have the potential for a significant financial impact on KCP&L in conjunction with achieving compliance with the proposed new nationwide limits. However, the financial consequences to KCP&L cannot be determined until final legislation is passed. KCP&L will continue to monitor the progress of these bills.

On February 14, 2002, President Bush unveiled his Clear Skies Initiative, which included a climate change policy. The climate change policy is a voluntary program that relies heavily on incentives to encourage industry to voluntarily limit emissions. The strategy includes tax credits, energy conservation programs, funding for research into new technologies, and a plan to encourage companies to track and report their emissions so that companies could gain credits for use in any future emissions trading program. The greenhouse strategy links growth in emissions of greenhouse gases to economic output. The administration's strategy is intended to reduce the greenhouse gas intensity of the U.S. economy by 18% over the next 10 years. Greenhouse gas intensity measures the ratio of greenhouse gas emissions to economic output as measured by Gross Domestic Product (GDP). Under this plan, as the economy grows, greenhouse gases also would continue to grow, although at a slower rate than they would have without these policies in place. When viewed per unit of economic output, the rate of emissions would drop. The plan projects that the U.S. will lower its rate of greenhouse gas emissions from an estimated 183 metric tons per $1 million of GDP in 2002 to 151 metric tons per $1 million of GDP by 2012.

On December 19, 2002, Great Plains Energy joined the Power Partners through Edison Electric Institute (EEI). Power Partners is a voluntary program with the DOE under which utilities commit to undertake measures to reduce, avoid or sequester CO_2 emissions. Eventually, industry sectors and individual companies are expected to enter into an umbrella memorandum of understanding (MOU) that will set forth programs for industries and individual companies to reduce greenhouse gas emissions.

On January 17, 2003, the EEI sent a letter to numerous Administration officials, in which the EEI committed to work with the government over the next decade to reduce the power sector's CO_2 emissions per kWh generated (carbon intensity) by the equivalent of 3% to 5% of the current level.

On December 13, 2004, Power Partners entered into a cooperative umbrella MOU with the DOE. This MOU contains supply and demand-side actions as well as offset projects that will be undertaken to reduce the power sector's CO_2 emissions per kWh generated over the next decade consistent with the EEI commitment of 3% to 5%. Individual companies, including KCP&L, will now begin entering into agreements with the DOE that set forth quantitative, concrete and specific activities to reduce, avoid or sequester greenhouse gases.

EPA New Source Review

The EPA is conducting an enforcement initiative under Section 114(a) of the Clean Air Act to determine whether modifications at selected coal-fired plants across the U.S. may have been subject to New Source Performance Standards (NSPS) or New Source Review (NSR) requirements. After an operator has received a Section 114 letter, the EPA requests data and reviews all expenditures at the plants to determine if they were routine maintenance or whether the expenditures were for substantial modifications or resulted in improved operations. If a plant, subject to a Section 114 letter, is determined to have been subject to NSPS or NSR, the plant could be required to install best available control technology or lowest achievable emission rate technology. KCP&L has not received a Section 114 letter to date.

Air Particulate Matter and Ozone
In July 1997, the EPA revised ozone and particulate matter air quality standards creating a new eight-hour ozone standard and establishing a new standard for particulate matter less than 2.5 microns (PM-2.5) in diameter. These standards were challenged in Federal court. However, the courts ultimately denied all state, industry and environmental groups petitions for review and thus upheld as valid the EPA's new eight-hour ozone and PM-2.5 National Ambient Air Quality Standards (NAAQS). In so doing, the court held that the EPA acted consistently with the Clean Air Act in setting the standards at the levels it chose and the EPA's actions were reasonable and not arbitrary and capricious, and cited the deference given the EPA's decision-making authority. The court stated that the extensive records established for each rule supported the EPA's actions in both rulemakings. This removed the last major hurdle to the EPA's implementation of stricter ambient air quality standards for ozone and fine particles. On December 17, 2004, the EPA designated the Kansas City area as attainment with respect to the PM-2.5 NAAQS.

On April 15, 2004, the EPA designated the Kansas City area as unclassifiable with respect to the eight-hour ozone NAAQS based on 2003 ozone season data. In the February 10, 2005, Federal Register, the EPA issued a proposed rule to redesignate Johnson, Linn, Miami and Wyandotte Counties in Kansas and Cass, Clay, Jackson and Platte Counties in Missouri to attainment for the eight-hour ozone standard. The EPA is scheduled to designate attainment areas for the eight-hour ozone NAAQS by April 15, 2005.

Water Use Regulations
On February 16, 2004, the EPA finalized the Phase II rule implementing Section 316(b) of the Clean Water Act establishing standards for cooling water intake structures at existing facilities. The final rule was published in the July 9, 2004, Federal Register with an effective date of September 7, 2004. This final regulation is applicable to certain existing power producing facilities that employ cooling water intake structures that withdraw 50 million gallons or more per day and use 25% or more of that water for cooling purposes. KCP&L is required to complete a Section 316(b) comprehensive demonstration study on each of its generating facilities' intake structures by the end of 2007. KCP&L plans to complete the comprehensive demonstration studies by the end of 2006 at an expected cost of $0.3 million to $0.5 million per facility. Depending on the outcome of the comprehensive demonstration studies, facilities may be required to implement technological, operational or restoration measures to achieve compliance. Compliance with the final rule is expected to be achieved between 2011 and 2014. Until the Section 316(b) comprehensive demonstration studies are completed, the impact of this final rule cannot be quantified.

Southwest Power Pool Regional Transmission Organization
Under the FERC Order 2000, KCP&L, as an investor-owned utility, is strongly encouraged to join a FERC approved Regional Transmission Organization (RTO). RTOs combine transmission operations of utility businesses into regional organizations that schedule transmission services and monitor the energy market to ensure regional transmission reliability and non-discriminatory access. The Southwest Power Pool (SPP), of which KCP&L is a member, obtained approval from FERC as an RTO in a January 24, 2005, order. KCP&L intends on participating in the SPP RTO; however, state regulatory approvals are required. KCP&L anticipates making the necessary applications to the MPSC and the KCC, during the second quarter of 2005 upon completion of the regional cost/benefit analysis currently being conducted for the SPP RTO. This cost/benefit analysis is being conducted under the

direction of the SPP Regional State Committee (composed of state commissions from the states where the SPP RTO operates) and is expected to be completed in the first quarter of 2005.

Pennsylvania Gross Receipts Tax Contingency
In January 2005, Strategic Energy was advised by the Pennsylvania Department of Revenue of a potential tax deficiency relating to state gross receipts tax on Strategic Energy's Provider of Last Resort (POLR) revenues from 2000 to 2002. After consulting with external legal counsel, management believes the Pennsylvania Department of Revenue does not have an appropriate basis for a tax deficiency claim. Management believes, but cannot assure, that Strategic Energy will prevail if a claim is formally asserted. Strategic Energy has not accrued for any portion of this contingency at December 31, 2004. If this claim is formally asserted and the Pennsylvania Department of Revenue is successful, Strategic Energy's total anticipated loss for the period 2000 through 2004 is a maximum of $16.4 million.

Income Tax Contingencies
See Note 11 for information regarding income tax contingences.

Contractual Commitments
Great Plains Energy's and consolidated KCP&L's expenses related to lease commitments are detailed in the following table.

	2004	2003	2002
		(millions)	
Consolidated KCP&L	$ 18.4	$23.1	$ 25.7
Other Great Plains Energy [a]	1.9	1.0	1.7
Total Great Plains Energy	$ 20.3	$ 24.1	$ 27.4

[a] Includes insignificant amounts related to discontinued operations.

Great Plains Energy's and consolidated KCP&L's contractual commitments excluding pensions and long-term debt are detailed in the following tables.

Great Plains Energy Contractual Commitments

	2005	2006	2007	2008	2009	After 2009	Total
				(millions)			
Lease commitments	$ 21.4	$ 21.7	$ 13.4	$ 11.1	$ 8.7	$ 85.2	$ 161.5
Purchase commitments							
Fuel [a]	74.2	80.7	63.7	30.9	7.3	43.2	300.0
Purchased capacity	10.9	5.4	5.5	5.6	4.4	24.8	56.6
Purchased power	697.2	201.5	65.6	10.3	3.7	3.7	982.0
Other	32.9	5.2	4.0	4.7	-	-	46.8
Total contractual commitments	$ 836.6	$ 314.5	$ 152.2	$ 62.6	$ 24.1	$ 156.9	$ 1,546.9

[a] Fuel commitments consists of commitments for nuclear fuel, coal and coal transportation costs.

Consolidated KCP&L Contractual Commitments

	2005	2006	2007	2008	2009	After 2009	Total
				(millions)			
Lease commitments	$ 20.1	$ 20.5	$ 12.4	$ 10.3	$ 8.7	$ 85.2	$ 157.2
Purchase commitments							
Fuel [a]	74.2	80.7	63.7	30.9	7.3	43.2	300.0
Purchased capacity	10.9	5.4	5.5	5.6	4.4	24.8	56.6
Other	32.9	5.2	4.0	4.7	-	-	46.8
Total contractual commitments	$ 138.1	$ 111.8	$ 85.6	$ 51.5	$ 20.4	$ 153.2	$ 560.6

[a] Fuel commitments consists of commitments for nuclear fuel, coal and coal transportation costs.

Lease commitments end in 2028 and include insignificant amounts for capital leases. These amounts exclude possible termination payments under the synthetic lease arrangement with the Lease Trust. As the managing partner of three jointly owned generating units, KCP&L has entered into leases for railcars to serve those units. Consolidated KCP&L has reflected the entire lease commitment in the above amounts, although the other owners will reimburse about $2.0 million per year ($21.9 million total).

KCP&L purchases capacity from other utilities and nonutility suppliers. Purchasing capacity provides the option to purchase energy if needed or when market prices are favorable. KCP&L has capacity sales agreements not included above that total $11.7 million for 2005, $11.4 million for 2006, $11.2 million per year for 2007 through 2009 and $23.5 million after 2009.

Purchased power represents Strategic Energy's agreements to purchase electricity at various fixed prices to meet estimated supply requirements. Strategic Energy has energy sales contracts not included above for 2005 through 2007 totaling $69.1 million, $8.7 million and $0.6 million, respectively.

Synthetic Lease

In 2001, KCP&L entered into a synthetic lease arrangement with a Lease Trust (Lessor) to finance the purchase, installation, assembly and construction of five combustion turbines and related property and equipment that added 385 MWs of peaking capacity (Project). Rental payments under the lease, which reflects interest payments only, began in 2004 and end in October 2006. KCP&L's expense for the synthetic lease was $1.9 million in 2004. Upon a default during the lease period, KCP&L's maximum obligation to the Lessor equals 100% of project costs, approximately $154.0 million. KCP&L's rental obligation for the years 2005 and 2006 are $5.3 million and $5.9 million, respectively. At the end of the lease term, KCP&L may choose to sell the project for the Lessor, guaranteeing that the Lessor receives a residual value for the Project in an amount, which may be up to 83.21% of the project cost. Alternatively, KCP&L may purchase the facility at an amount equal to the project cost.

The Lease Trust, a special purpose entity, acting as Lessor in the synthetic lease arrangement discussed above, is considered a variable interest entity under FIN No. 46. Because KCP&L has variable interests in the Lease Trust, including among other things, a residual value guarantee provided to the Lessor, KCP&L is the primary beneficiary of the Lease Trust. The Lease Trust was consolidated in 2003, as required by FIN No. 46. As a result, Great Plains Energy's and consolidated KCP&L's depreciation expense increased $5.1 million and $1.3 million in 2004 and 2003, respectively, with offsetting recognition of minority interest.

14. GUARANTEES

In the normal course of business, Great Plains Energy and certain of its subsidiaries enter into various agreements providing financial or performance assurance to third parties on behalf of certain subsidiaries. Such agreements include, for example, guarantees and indemnification of letters of credit and surety bonds. These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to a subsidiary on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended business purposes. The majority of these agreements guarantee the Company's own future performance, so a liability for the fair value of the obligation is not recorded.

As of December 31, 2004, KCP&L had guarantees, with a maximum potential of $6.4 million, for energy savings under agreements with several customers that expire over the next six years. In most cases, a subcontractor would indemnify KCP&L for any payments made by KCP&L under these guarantees. These guarantees were entered into before December 31, 2002; therefore, a liability was not recorded in accordance with FIN No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Guarantees of Indebtedness of Others."

15. LEGAL PROCEEDINGS

Strategic Energy

On March 23, 2004, Robert C. Haberstroh filed suit for breach of employment contract and violation of the Pennsylvania Wage Payment Collection Act against Strategic Energy Partners, Ltd. (Partners), SE Holdings and Strategic Energy in the Court of Common Pleas of Allegheny County, Pennsylvania. Mr. Haberstroh claims that he acquired an equity interest in Partners under the terms of his employment agreement and that through a series of transactions, Mr. Haberstroh's equity interest became an equity interest in SE Holdings. In 2001, Mr. Haberstroh's employment was terminated and SE Holdings redeemed his equity interest. Mr. Haberstroh is seeking the loss of his non-equity compensation (including salary, bonus and benefits) and equity compensation and associated distributions (his equity interest in SE Holdings).

Strategic Energy has filed a counterclaim against Mr. Haberstroh for breach of contract. SE Holdings, and its direct and indirect owners, have agreed to indemnify Strategic Energy and Innovative Energy Consultants Inc. against any judgment or settlement of Mr. Haberstroh's claim that relates to his equity interest in SE Holdings, up to a maximum amount of approximately $8 million.

See Note 12 for further information regarding related party transactions.

KLT Gas

On July 28, 2004, KLT Gas received a Notice and Demand for Arbitration Pursuant to Joint Operating Agreement from SWEPI LP doing business as Shell Western E&P and formerly known as Shell Western E&P Inc. (Shell). Prior to the October 2004 sale (with a July 1, 2004, effective date) of KLT Gas' working interests in certain oil and gas leases in Duval County, Texas to Shell, KLT Gas had a 50% working interest in the leases. Shell held the other 50% working interest and was the operator of the properties under a joint operating agreement, as amended (JOA). Three groups of current or past lessors filed suit against Shell in Duval County, Texas, alleging various claims against Shell. Additionally, Shell has been party to ongoing proceedings before the Texas Railroad Commission relating to a well drilled on acreage adjacent to the properties of Shell and KLT Gas mentioned above. Through arbitration, Shell is seeking recovery from KLT Gas of 50% of the fees and costs incurred in the three lawsuits and the Texas Railroad Commission proceedings and settlement proceeds paid with respect to the three lawsuits, which Shell asserts is a total amount of not less than $5.4 million for KLT Gas' share. Shell is also seeking a declaration that the fees and costs incurred and settlement proceeds paid, including any fees and costs incurred in the future, are reimbursable expenses under the JOA. Shell is seeking a ruling compelling KLT Gas to pay Shell immediately all sums deemed to be due pursuant to the arbitration. On August 17, 2004, KLT Gas submitted its notice of defense generally asserting that there is no contractual basis or implied duty for reimbursement or contribution regarding the settlements and there is no contractual basis for reimbursement or contribution regarding the Texas

Railroad Commission proceedings. KLT Gas also asserted counterclaims based upon misrepresentations and promissory estoppel, gross negligence in imprudent operations, full accounting under the JOA and offset. The arbitration is currently scheduled to begin in May 2005. KLT Gas and its counsel continue to evaluate KLT Gas' rights and obligations under the JOA as well as other possible counterclaims that KLT Gas may have against Shell; however, management is unable to predict the ultimate outcome of this demand for arbitration.

Hawthorn No. 5 Subrogation Litigation
KCP&L filed suit against National Union Fire Insurance Company of Pittsburgh, Pennsylvania (National Union) and Travelers Indemnity Company of Illinois (Travelers) in Missouri state court on June 14, 2002, which was removed to the U.S. District Court for the Western District of Missouri. In 1999, there was a boiler explosion at KCP&L's Hawthorn No. 5 generating unit, which was subsequently reconstructed and returned to service. National Union and Reliance National Insurance had issued a $200 million primary insurance policy and Travelers had issued a $100 million secondary insurance policy covering Hawthorn No. 5. A dispute arose among KCP&L, National Union and Travelers regarding the amount payable under these insurance policies for the reconstruction of Hawthorn No. 5 and replacement power expenses, and KCP&L filed suit against the two carriers. In that suit, KCP&L sought recovery, subject to the limits of the insurance policies, of Hawthorn No. 5 reconstruction costs and replacement power expenses, plus damages and attorneys' fees from National Union for failing to pay the full amount of its insurance policy. In 2004, KCP&L settled with National Union for the amount remaining under the primary insurance policy limit, less the applicable deductible. In January 2005, KCP&L settled with Travelers for $10 million. This settlement does not encompass any alleged subrogation claims Travelers may have against National Union or any alleged subrogation claims with regard to possible future recoveries by National Union and KCP&L in the litigation described in the next paragraph.

KCP&L also filed suit on April 3, 2001, in Jackson County, Missouri Circuit Court against multiple defendants who are alleged to have responsibility for the Hawthorn No. 5 boiler explosion. KCP&L and National Union have entered into a subrogation allocation agreement under which recoveries in this suit are generally allocated 55% to National Union and 45% to KCP&L. Certain defendants have been dismissed from the suit and various other defendants have settled with KCP&L. KCP&L received $38.2 million under the terms of the subrogation allocation agreement. Trial of this case with the one remaining defendant resulted in a March 2004 jury verdict finding KCP&L's damages as a result of the explosion were $452 million. After deduction of amounts received from pre-trial settlements with other defendants and an amount for KCP&L's comparative fault (as determined by the jury), the verdict would have resulted in an award against the defendant of approximately $97.6 million (of which KCP&L would have received $33 million pursuant to the subrogation allocation agreement after payment of attorney's fees). In response to post-trial pleadings filed by the defendant, in May 2004 the trial judge reduced the award against the defendant to $0.2 million. Both KCP&L and the defendant have appealed this case to the Court of Appeals for the Western District of Missouri.

KLT Telecom
On December 31, 2001, a subsidiary of KLT Telecom, DTI Holdings, Inc. (Holdings) and its subsidiaries Digital Teleport Inc. (Digital Teleport) and Digital Teleport of Virginia, Inc., filed separate voluntary petitions in the Bankruptcy Court for the Eastern District of Missouri for reorganization under Chapter 11 of the U.S. Bankruptcy Code. In 2003, the Bankruptcy Court confirmed the plan of reorganization for these three companies. The Bankruptcy Court conducted an evidentiary hearing regarding three priority proofs of claim by the Missouri Department of Revenue (MODOR) in the aggregate amount of $2.8 million (collectively, the MODOR Claim), and ruled substantially in favor of Digital Teleport. MODOR has appealed this ruling. KLT Telecom may receive an additional distribution from the bankruptcy estate; however, the amount and timing of any additional distribution is dependent upon the outcome of the MODOR appeal.

KLT Telecom originally acquired a 47% interest in DTI in 1997. On February 8, 2001, KLT Telecom acquired control of DTI by purchasing shares from another Holdings shareholder, Richard D. Weinstein (Weinstein), increasing its ownership to 83.6%. In connection with this purchase, KLT Telecom granted Weinstein a put option. The put option provided for the sale by Weinstein of his remaining shares in Holdings to KLT Telecom during a period beginning September 1, 2003, and ending August 31, 2005. The put option provides for an aggregate exercise price for these remaining shares equal to their fair market value with an aggregate floor amount of $15 million. The floor amount of the put option was fully reserved during 2001. On September 2, 2003, Weinstein delivered to KLT Telecom notice of the exercise of his put option. KLT Telecom declined to pay Weinstein any amount under the put option because, among other things, the stock of Holdings has been cancelled and extinguished pursuant to the joint Chapter 11 plan confirmed by the Bankruptcy Court. Weinstein has sued KLT Telecom for allegedly breaching the put option. Trial of this suit is scheduled to begin in May 2005.

16. ASSET RETIREMENT OBLIGATIONS

Effective January 1, 2003, the Company adopted SFAS No. 143. SFAS No. 143 provides accounting requirements for the recognition and measurement of liabilities associated with the retirement of tangible long-lived assets. Under the standard, these liabilities are recognized at fair value as incurred and capitalized as part of the cost of the related long-lived asset. Accretion of the liabilities due to the passage of time is recorded as an operating expense. Retirement obligations associated with long-lived assets included within the scope of SFAS No. 143 are those for which a legal obligation exists under enacted laws, statutes and written or oral contracts, including obligations arising under the doctrine of promissory estoppel.

The adoption of SFAS No. 143 changed the accounting for and the method used to report KCP&L's obligation to decommission its 47% share of Wolf Creek. The legal obligation to decommission Wolf Creek was incurred when the plant was placed in service in 1985. The estimated liability, recognized on KCP&L's balance sheet at January 1, 2003, was based on a third party nuclear decommissioning study conducted in 2002. KCP&L used a credit-adjusted risk free discount rate of 6.42% to calculate the retirement obligation. This estimated rate was based on the rate KCP&L could issue 30-year bonds, adjusted downward to reflect the portion of the anticipated costs in current year dollars that had been funded at date of adoption through a tax-qualified trust fund. The cumulative impact of prior decommissioning accruals recorded consistent with rate orders issued by the MPSC and KCC has been reversed with an offsetting reduction of the regulatory asset established upon adoption of SFAS No. 143, as described below. Amounts collected through these rate orders have been deposited in a legally restricted external trust fund. The fair market value of the trust fund was $84.1 million and $75.0 million at December 31, 2004 and 2003, respectively.

KCP&L also must recognize, where possible to estimate, the future costs to settle other legal liabilities including the removal of water intake structures on rivers, capping/filling of piping at levees following steam power plant closures and capping/closure of ash landfills. Estimates for these liabilities are based on internal engineering estimates of third party costs to remove the assets in satisfaction of legal obligations and have been discounted using credit adjusted risk free rates ranging from 5.25% to 7.50% depending on the anticipated settlement date.

Revisions to the estimated liabilities of KCP&L could occur due to changes in the decommissioning or other cost estimates, extension of the nuclear operating license or changes in federal or state regulatory requirements.

On January 1, 2003, KCP&L recorded an ARO of $99.2 million, reversed the decommissioning liability of $64.6 million previously accrued and increased property and equipment, net of accumulated depreciation, by $18.3 million. KCP&L is a regulated utility subject to the provisions of SFAS No. 71

and management believes it is probable that any differences between expenses under SFAS No. 143 and expenses recovered currently in rates will be recoverable in future rates. As a result, the $16.3 million net cumulative effect ($80.9 million gross cumulative effect net of $64.6 million decommissioning liability previously accrued) of the adoption of SFAS No. 143 was recorded as a regulatory asset and therefore, had no impact on net income.

In addition, KCP&L recognizes removal costs for utility assets that do not have an associated legal retirement obligation. Historically, these removal costs have been reflected as a component of depreciation in accordance with regulatory treatment. In conjunction with the adoption of SFAS No. 143, non-legal costs of removal were reclassified for all periods presented from accumulated depreciation to a regulatory asset.

KCP&L has legal ARO for certain other assets where it is not possible to estimate the time period when the obligations will be settled. Consequently, the retirement obligations cannot be measured at this time. For transmission easements obtained by condemnation, KCP&L must remove its transmission lines if the line is de-energized. It is extremely difficult to obtain siting for new transmission lines. Consequently, KCP&L does not anticipate de-energizing any of its existing lines. KCP&L also operates, under state permits, ash landfills at several of its power plants. While the life of the ash landfill at one plant can be estimated and is included in the estimated liabilities above, the future life of ash landfills at other permitted landfills cannot be estimated. KCP&L can continue to maintain permits for these landfills after the adjacent plant is closed.

KLT Gas had estimated liabilities for gas well plugging and abandonment, facility removal and surface restoration. As a result of the sale of the KLT Gas portfolio discussed in Note 6, the new owners have assumed the ARO related to the KLT Gas portfolio estimated to be $1.8 million as December 31, 2003.

The following table summarizes the change in Great Plains Energy's and consolidated KCP&L's ARO, excluding prior year amounts included in Liabilities of Discontinued Operations. Pro forma amounts for 2002 illustrate the effect on ARO if the provisions of SFAS No. 143 had been applied prior to the January 1, 2003, adoption and were measured using assumptions consistent with the period of adoption.

December 31	2004	2003	2002
		(millions)	
ARO beginning of period	$ 106.7	$ 99.2	$ 93.1
Additions	-	1.0	-
Accretion	7.0	6.5	6.1
ARO end of period	$ 113.7	$ 106.7	$ 99.2

17. SEGMENT AND RELATED INFORMATION

Great Plains Energy

Great Plains Energy has two reportable segments based on its method of internal reporting, which generally segregates the reportable segments based on products and services, management responsibility and regulation. The two reportable business segments are KCP&L, an integrated, regulated electric utility, which provides reliable, affordable electricity to customers; and Strategic Energy, a competitive electricity supplier, which operates in several electricity markets offering retail choice. Other includes the operations of HSS, GPP, Services, all KLT Inc. operations other than Strategic Energy, unallocated corporate charges and intercompany eliminations. Intercompany eliminations include insignificant amounts of intercompany financing related activities. The summary of significant accounting policies applies to all of the reportable segments. For segment reporting, each segment's income taxes include the effects of allocating holding company tax benefits. Segment performance is evaluated based on net income.

The tables below reflect summarized financial information concerning Great Plains Energy's reportable segments.

2004	KCP&L	Strategic Energy	Other	Great Plains Energy
		(millions)		
Operating revenues	$ 1,090.1	$ 1,372.4	$ 1.5	$ 2,464.0
Depreciation	(144.3)	(4.8)	(1.0)	(150.1)
Interest charges	(73.7)	(0.7)	(8.6)	(83.0)
Income taxes	(55.7)	(24.3)	25.5	(54.5)
Loss from equity investments	-	-	(1.5)	(1.5)
Discontinued operations	-	-	7.3	7.3
Net income (loss)	150.0	42.5	(11.7)	180.8

2003	KCP&L	Strategic Energy	Other	Great Plains Energy
		(millions)		
Operating revenues	$ 1,054.9	$ 1,091.0	$ 2.1	$ 2,148.0
Depreciation	(139.9)	(1.7)	(1.2)	(142.8)
Interest charges	(69.9)	(0.4)	(5.9)	(76.2)
Income taxes	(84.4)	(30.2)	36.0	(78.6)
Loss from equity investments	-	-	(2.0)	(2.0)
Discontinued operations	-	-	(44.8)	(44.8)
Net income (loss)	127.2	39.6	(21.9)	144.9

2002	KCP&L	Strategic Energy	Other	Great Plains Energy
		(millions)		
Operating revenues	$ 1,009.9	$ 789.5	$ 2.9	$ 1,802.3
Depreciation	(144.3)	(0.9)	(1.6)	(146.8)
Interest charges	(80.3)	(0.3)	(6.8)	(87.4)
Income taxes	(63.4)	(25.2)	37.3	(51.3)
Loss from equity investments	-	-	(1.2)	(1.2)
Discontinued operations	-	-	(7.5)	(7.5)
Cumulative effect of a change in accounting principle	-	-	(3.0)	(3.0)
Net income (loss)	102.9	29.7	(6.4)	126.2

	KCP&L	Strategic Energy	Other	Great Plains Energy
2004		(millions)		
Assets	$ 3,330.2	$ 407.7	$ 61.0	$ 3,798.9
Capital expenditures [a]	190.8	2.6	3.3	196.7
2003				
Assets	$ 3,293.5	$ 283.0	$ 105.5	$ 3,682.0
Capital expenditures [a]	148.8	3.1	-	151.9
2002				
Assets	$ 3,084.5	$ 226.0	$ 206.6	$ 3,517.1
Capital expenditures [a]	132.1	2.1	(0.3)	133.9

[a] Capital expenditures reflect annual amounts for the periods presented.

Consolidated KCP&L

The following tables reflect summarized financial information concerning consolidated KCP&L's reportable segment. Other includes the operations of HSS and intercompany eliminations. Intercompany eliminations include insignificant amounts of intercompany financing related activities.

2004	KCP&L	Other	Consolidated KCP&L
		(millions)	
Operating revenues	$ 1,090.1	$ 1.5	$ 1,091.6
Depreciation	(144.3)	(0.9)	(145.2)
Interest charges	(73.7)	(0.5)	(74.2)
Income taxes	(55.7)	2.9	(52.8)
Net income (loss)	150.0	(6.7)	143.3

2003	KCP&L	Other	Consolidated KCP&L
		(millions)	
Operating revenues	$ 1,054.9	$ 2.1	$ 1,057.0
Depreciation	(139.9)	(1.1)	(141.0)
Interest charges	(69.9)	(0.4)	(70.3)
Income taxes	(84.4)	0.9	(83.5)
Discontinued operations	-	(8.7)	(8.7)
Net income (loss)	127.2	(10.0)	117.2

2002	KCP&L	Other	Consolidated KCP&L
		(millions)	
Operating revenues	$ 1,009.9	$ 2.9	$ 1,012.8
Depreciation	(144.3)	(1.2)	(145.5)
Interest charges	(80.3)	-	(80.3)
Income taxes	(63.4)	0.5	(62.9)
Discontinued operations	-	(4.0)	(4.0)
Cumulative effect of a change in accounting principle	-	(3.0)	(3.0)
Net income (loss)	102.9	(7.2)	95.7

	KCP&L	Other	Consolidated KCP&L
2004		(millions)	
Assets	$ 3,330.2	$ 7.2	$ 3,337.4
Capital expenditures [a]	190.8	-	190.8
2003			
Assets	$ 3,293.5	$ 9.1	$ 3,302.6
Capital expenditures [a]	148.8	-	148.8
2002			
Assets	$ 3,084.5	$ 54.7	$ 3,139.2
Capital expenditures [a]	132.1	0.1	132.2

[a] Capital expenditures reflect annual amounts for the periods presented.

18. SHORT-TERM BORROWINGS AND SHORT-TERM BANK LINES OF CREDIT

In December 2004, Great Plains Energy syndicated a $550 million, five-year revolving credit facility with a group of banks replacing a $150.0 million 364-day revolving credit facility and a $150.0 million three-year revolving credit facility with a group of banks that were syndicated earlier in 2004. Those latter two facilities had replaced a $225.0 million revolving credit facility with a group of banks. A default by Great Plains Energy or any of its significant subsidiaries of other indebtedness totaling more than $25.0 million is a default under the current facility. Under the terms of the agreement, Great Plains Energy is required to maintain a consolidated indebtedness to consolidated capitalization ratio, as defined in the agreement, not greater than 0.65 to 1.00 at all times. At December 31, 2004, the Company was in compliance with this covenant. At December 31, 2004, Great Plains Energy had $20.0 million of outstanding borrowings with an interest rate of 3.04% and had issued letters of credit totaling $8.0 million under the credit facility as credit support for Strategic Energy. At December 31, 2003, Great Plains Energy had $87.0 million of outstanding borrowings under the $225.0 million revolving credit facility with a weighted-average interest rate of 2.12% and had issued a letter of credit for $15.8 million as credit support for Strategic Energy.

KCP&L's short-term borrowings consist of funds borrowed from banks or through the sale of commercial paper as needed. In December 2004, KCP&L syndicated a $250 million five-year revolving credit facility. This facility replaced $155 million in 364-day bilateral credit lines KCP&L had in place with a group of banks. A default by KCP&L on other indebtedness totaling more than $25.0 million is a default under the current facility. Under the terms of the agreement, KCP&L is required to maintain a consolidated indebtedness to consolidated capitalization ratio, as defined in the agreement, not greater than 0.65 to 1.00 at all times. At December 31, 2004, KCP&L was in compliance with this covenant. At December 31, 2004 and 2003, KCP&L had no short-term borrowings outstanding.

During 2004, Strategic Energy syndicated a $125.0 million three-year revolving credit facility with a group of banks. Great Plains Energy has guaranteed $25.0 million of this facility. This facility replaced a $95.0 million revolving credit facility with a group of banks. A default by Strategic Energy of other indebtedness, as defined in the new facility, totaling more than $7.5 million is a default under the facility. Under the terms of this agreement, Strategic Energy is required to maintain a minimum net worth of $62.5 million, a maximum funded indebtedness to EBITDA ratio of 2.25 to 1.00, a minimum fixed charge coverage ratio of at least 1.05 to 1.00 and a minimum debt service coverage ratio of at least 4.00 to 1.00 as those are defined in the agreement. In the event of a breach of one or more of these four covenants, so long as no other default has occurred, Great Plains Energy may cure the breach through a cash infusion, a guarantee increase or a combination of the two. At December 31, 2004, Strategic Energy was in compliance with these covenants. At December 31, 2004, $69.2 million in letters of credit had been issued and there were no borrowings under the agreement. At December 31, 2003, $58.5 million in letters of credit had been issued under the previous agreement.

On June 30, 2003, HSS completed the disposition of its interest in RSAE. RSAE's line of credit totaling $27 million was cancelled. With proceeds from a note to Great Plains Energy, HSS repaid $22.1 million on the supported bank line. HSS repaid all but an immaterial amount of the notes payable to Great Plains Energy during 2004. At December 31, 2003, the notes payable to Great Plains Energy totaled $22.0 million. See Note 7 for additional information concerning the disposition of RSAE.

19. LONG-TERM DEBT AND EIRR BONDS CLASSIFIED AS CURRENT LIABILITIES

Great Plains Energy and consolidated KCP&L's long-term debt is detailed in the following table.

		December 31	
	Year Due	2004	2003
Consolidated KCP&L		(thousands)	
General Mortgage Bonds			
7.95%* and 7.55%** Medium-Term Notes	2007	$ **500**	$ 55,000
2.26%* and 2.36%** EIRR bonds	2012-2023	**158,768**	158,768
Senior Notes			
7.125%	2005	**250,000**	250,000
6.500%	2011	**150,000**	150,000
6.000%	2007	**225,000**	225,000
Unamortized discount		**(465)**	(689)
EIRR bonds			
2.29%* and 2.16%** Series A & B	2015	**106,991**	108,919
2.38%* and 2.25%** Series C	2017	**50,000**	50,000
2.29%* and 2.16%** Series D	2017	**40,183**	40,923
8.3% Junior Subordinated Deferred Interest Bonds		**-**	154,640
2.10%* and 1.25%** Combustion Turbine Synthetic Lease	2006	**145,274**	143,811
Current liabilities			
EIRR bonds classified as current		**(85,922)**	(129,288)
Current maturities		**(250,000)**	(54,500)
Total consolidated KCP&L excluding current liabilities		**790,329**	1,152,584
Other Great Plains Energy			
4.25% FELINE PRIDES Senior Notes	2009	**163,600**	-
7.64%* and 7.84%** Affordable Housing Notes	2005-2008	**5,761**	10,564
Current maturities		**(3,230)**	(4,803)
Total consolidated Great Plains Energy excluding current maturities		$ **956,460**	$ 1,158,345

* Weighted-average rate as of December 31, 2004
** Weighted-average rate as of December 31, 2003

Amortization of Debt Expense

Great Plains Energy's and consolidated KCP&L's amortization of debt expense is detailed in the following table.

	2004	2003	2002
		(millions)	
Consolidated KCP&L	$ 2.1	$ 2.1	$ 2.1
Other Great Plains Energy	1.8	1.4	0.8
Total Great Plains Energy	$ 3.9	$ 3.5	$ 2.9

KCP&L General Mortgage Bonds

KCP&L has issued mortgage bonds under the General Mortgage Indenture and Deed of Trust dated December 1, 1986, as supplemented. The Indenture creates a mortgage lien on substantially all utility plant. Mortgage bonds secure $159.3 million and $213.8 million of medium-term notes and Environmental Improvement Revenue Refunding (EIRR) bonds at December 31, 2004 and 2003, respectively. In 2004, KCP&L redeemed $54.5 million of its medium-term notes at maturity.

In August 2004, KCP&L secured a municipal bond insurance policy as a credit enhancement to its secured 1992 series EIRR bonds totaling $31.0 million. This municipal bond insurance policy replaced a 364-day credit facility with a bank, which expired in August 2004 that previously supported full liquidity of these bonds. These variable-rate secured EIRR bonds with a final maturity in 2017 are remarketed on a weekly basis through a Dutch auction process. The insurance agreement between KCP&L and XL Capital Assurance Inc. (XLCA), the issuer of the municipal bond insurance policy, provides for reimbursement by KCP&L for any amounts that XLCA pays under the municipal bond insurance policy. The insurance policy is in effect for the term of the bonds. The insurance agreement contains a covenant that the indebtedness to total capitalization ratio of KCP&L and its consolidated subsidiaries will not be greater than 0.68 to 1.00. At December 31, 2004, KCP&L was in compliance with this covenant. KCP&L is also restricted from issuing additional bonds under its General Mortgage Indenture if, after giving effect to such additional bonds, the proportion of secured debt to total indebtedness would be more than 75%, or more than 50% if the long term rating for such bonds by Standard & Poor's or Moody's Investors Service would be at or below A- or A3, respectively. In the event of a default under the insurance agreement, XLCA may take any available legal or equitable action against KCP&L, including seeking specific performance of the covenants.

During 2004, KCP&L remarketed its secured 1994 series EIRR bonds totaling $35.9 million at a fixed rate of 2.25% ending August 31, 2005. If the bonds could not be remarketed, KCP&L would be obligated to either purchase or retire the bonds. KCP&L also remarketed its secured 1993 series EIRR bonds totaling $12.4 million at a fixed rate of 4.0% until maturity at January 2, 2012. The previous interest rate periods on these two series, with interest rates of 3.9%, expired on August 31, 2004. The $35.9 million of secured 1994 series EIRR bonds were classified as current liabilities at December 31, 2004. Both of these series were classified as current liabilities at December 31, 2003.

KCP&L Unsecured Notes

KCP&L had $196.5 million of unsecured EIRR bonds outstanding excluding the fair value of interest rate swaps of $0.7 million and $3.3 million at December 31, 2004 and 2003, respectively. During 2004, KCP&L remarketed its 1998 Series C EIRR bonds, totaling $50.0 million due 2017, at a fixed rate of 2.38% ending August 31, 2005. If the bonds could not be remarketed, KCP&L would be obligated to either purchase or retire the bonds. The previous interest rate period on this series, with an interest rate of 2.25%, expired on August 31, 2004. The Series C EIRR bonds were classified as current liabilities at December 31, 2004 and 2003.

In 1997, KCPL Financing I issued $150.0 million of 8.3% preferred securities and KCP&L invested $4.6 million in common securities of KCPL Financing I. The sole asset of KCPL Financing I was the $154.6 million principal amount of 8.3% Junior Subordinated Deferrable Interest Debentures, due 2037, issued by KCP&L. In July 2004, KCP&L redeemed the $154.6 million 8.3% Junior Subordinated Deferred Interest Debentures. KCPL Financing I used the proceeds from the repayment of the 8.3% Junior Subordinated Deferrable Interest Debentures to redeem the $4.6 million of common securities held by KCP&L and the $150.0 million of 8.3% preferred securities.

Other Great Plains Energy Long-Term Debt

Great Plains Energy filed a registration statement, which became effective in April 2004, for the issuance of an aggregate amount up to $500.0 million of any combination of senior debt securities, subordinated debt securities, trust preferred securities and related guarantees, common stock, warrants, stock purchase contracts or stock purchase units. The prospectus filed with this registration statement also included $148.2 million of securities remaining available to be offered under a prior registration statement providing for an aggregate amount of availability of $648.2 million.

In June 2004, Great Plains Energy issued $163.6 million of FELINE PRIDES under this registration statement. After this transaction and the stock issuance discussed in Note 20, $171.0 million remains available under the registration statement. FELINE PRIDES, each with a stated amount of $25, initially consist of an interest in a senior note due February 16, 2009, and a contract requiring the holder to purchase the Company's common stock on February 16, 2007. Each purchase contract obligates the holder of the purchase contract to purchase, and Great Plains Energy to sell, on February 16, 2007, for $25 in cash, newly issued shares of the Company's common stock equal to the settlement rate. The settlement rate will vary according to the applicable market value of the Company's common stock at the settlement date. Applicable market value will be measured by the average of the closing price per share of the Company's common stock on each of the 20 consecutive trading days ending on the third trading day immediately preceding February 16, 2007. The settlement rate will be applied to the 6.5 million FELINE PRIDES at the settlement date to issue a number of common shares determined as described in the following table.

Applicable market value	**Settlement rate (in common shares)**	**Market value per common share (a)**
$35.40 or greater	0.7062 to 1	Greater than $25 per common share
$35.40 to $30.00	$25 divided by the applicable market value to 1	Equal to $25 per common share
$30.00 or less	0.8333 to 1	Less than $25 per common share

[a] Assumes that the market price of the Company's common stock on February 16, 2007, is the same as the applicable market value.

Great Plains Energy will make quarterly contract adjustment payments at the rate of 3.75% per year and interest payments at the rate of 4.25% per year both payable in February, May, August and November of each year, which commenced August 16, 2004. Great Plains Energy must attempt to remarket the senior notes, in whole but not in part. If the senior notes are not successfully remarketed by February 16, 2007, Great Plains Energy will exercise its rights as a secured party to dispose of the senior notes in accordance with applicable law and satisfy in full each holder's obligation to purchase the Company's common stock under the purchase contracts.

The June 2004 fair value of the contract adjustment payments of $15.4 million was recorded as a liability in other deferred credits and other liabilities with a corresponding amount recorded as capital stock premium and expense on Great Plains Energy's consolidated balance sheet. Expenses incurred with the offering were allocated between the senior notes and the purchase contracts. Expenses allocated to the senior notes of $1.2 million have been deferred and are being recognized as interest expense over the term of the notes. Expenses allocated to the purchase contracts of $4.2 million were recorded as capital stock premium and expense. Great Plains Energy has the right to defer the contract adjustment payment on the purchase contracts, but not the interest payments on the senior notes. In the event Great Plains Energy exercises its option to defer the payment of contract adjustment payments, Great Plains Energy and its subsidiaries are not permitted to, with certain exceptions, declare or pay dividends on, make distributions with respect to, or redeem, purchase or acquire, or make a liquidation payment with respect to, any capital stock of Great Plans Energy until the deferred contract adjustment payments have been paid.

KLT Investments' affordable housing notes are collateralized by the affordable housing investments. Most of the notes also require the greater of 15% of the outstanding note balances or the next annual installment to be held as cash, cash equivalents or marketable securities. At December 31, 2004, the collateral was held entirely as cash and totaled $3.7 million. At December 31, 2003, collateral of $4.7 million was held as cash and $1.5 million was held in equity securities for these notes. The equity securities were included in other investments and nonutility property on Great Plains Energy's consolidated balance sheets.

Scheduled Maturities
Great Plains Energy's and consolidated KCP&L's long-term debt maturities for the next five years are detailed in the following table.

	2005	2006	2007	2008	2009
			(millions)		
Consolidated KCP&L	$ 250.0	$ 145.2	$ 225.5	$ -	$ -
Other Great Plains Energy	3.2	1.8	164.1	0.3	-
Total Great Plains Energy	$ 253.2	$ 147.0	$ 389.6	$ 0.3	$ -

20. COMMON STOCK EQUITY AND PREFERRED STOCK

Common Stock Equity
In 2004, Great Plains Energy issued 5.0 million shares of common stock at $30 per share under the registration statement discussed in Note 19 with $150.0 million in gross proceeds. Issuance costs of $5.4 million are reflected in capital stock premium and expense on Great Plains Energy's consolidated balance sheet and statement of common stock equity at December 31, 2004.

Treasury shares are held for future distribution upon exercise of options issued in conjunction with the Company's equity compensation plan.

Great Plains Energy has 3.0 million shares of common stock registered with the SEC for a Dividend Reinvestment and Direct Stock Purchase Plan (Plan). The Plan allows for the purchase of common shares by reinvesting dividends or making optional cash payments. Great Plains Energy can issue new shares or purchase shares on the open market for the Plan. At December 31, 2004, 2.2 million shares remained available for future issuances.

Great Plains Energy has 9.3 million shares of common stock registered with the SEC for a defined contribution savings plan. The Company matches employee contributions, subject to limits. At December 31, 2004, 1.1 million shares remained available for future issuances.

Under the 35 Act, Great Plains Energy and KCP&L can pay dividends only out of retained or current earnings, unless authorized to do otherwise by the SEC. Under stipulations with the MPSC and KCC, Great Plains Energy and KCP&L have committed to maintain consolidated common equity of not less than 30% and 35%, respectively. Pursuant to SEC order, Great Plains Energy's and KCP&L's authorization to issue securities is conditioned on maintaining a consolidated common equity capitalization of at least 30%.

Great Plains Energy's Articles of Incorporation contain a restriction related to the payment of dividends in the event common equity falls to 25% of total capitalization. If preferred stock dividends are not declared and paid when scheduled, Great Plains Energy could not declare or pay common stock dividends or purchase any common shares. If the unpaid preferred stock dividends equal four or more full quarterly dividends, the preferred shareholders, voting as a single class, could elect the smallest number of Directors necessary to constitute a majority of the full Board of Directors.

Great Plains Energy made capital contributions to KCP&L of $225 million and $100 million in 2004 and 2003, respectively. These contributions were used to pay down long-term debt. At December 31, 2004, KCP&L's capital contributions from Great Plains Energy totaled $400 million which is reflected in common stock in the consolidated KCP&L balance sheet.

Preferred Stock
As of December 31, 2004, 1.6 million shares of Cumulative No Par Preferred Stock and 11.0 million shares of no par Preference Stock were authorized under Great Plains Energy's Articles of Incorporation. Great Plains Energy has the option to redeem the $39.0 million of issued Cumulative Preferred Stock at prices approximating par or stated value.

21. DERIVATIVE FINANCIAL INSTRUMENTS

The Company's activities expose it to a variety of market risks including interest rates and commodity prices. Management has established risk management policies and strategies to reduce the potentially adverse effects that the volatility of the markets may have on its operating results. The Company's risk management activities, including the use of derivatives, are subject to the management, direction and control of internal risk management committees. The Company's interest rate risk management strategy uses derivative instruments to adjust the Company's liability portfolio to optimize the mix of fixed and floating rate debt within an established range. The Company maintains commodity-price risk management strategies that use derivative instruments to reduce the effects of fluctuations on purchased power expense caused by commodity price volatility. Counterparties on commodity derivatives and interest rate swap agreements expose the Company to credit loss in the event of nonperformance. This credit loss is limited to the cost of replacing these contracts at current market rates. Derivative instruments measured at fair value are recorded on the balance sheet as an asset or liability. Changes in the fair value are recognized currently in net income unless specific hedge accounting criteria are met.

Fair Value Hedges - Interest Rate Risk Management
In 2002, KCP&L remarketed its 1998 Series A, B, and D EIRR bonds totaling $146.5 million to a 5-year fixed interest rate of 4.75% ending October 1, 2007. Simultaneously with the remarketing, KCP&L entered into an interest rate swap for the $146.5 million based on the London Interbank Offered Rate (LIBOR) to effectively create a floating interest rate obligation. The transaction is a fair value hedge with no ineffectiveness. Changes in the fair market value of the swap are recorded on the balance sheet as an asset or liability with an offsetting entry to the respective debt balances with no net impact on net income. The fair value of the swap was an asset of $0.7 million and $3.3 million at December 31, 2004 and 2003, respectively.

Cash Flow Hedges - Commodity Risk Management
KCP&L's risk management policy is to use derivative hedge instruments to mitigate its exposure to market price fluctuations on a portion of its projected natural gas purchases to meet generation requirements for retail and firm wholesale sales. As of December 31, 2004, KCP&L had slightly under half of its 2005 projected natural gas usage for retail load and firm MWh sales hedged. These hedging instruments are designated as cash flow hedges. The fair values of these instruments are recorded as current assets or current liabilities with an offsetting entry to OCI for the effective portion of the hedge. To the extent the hedges are not effective, the ineffective portion of the change in fair market value is recorded currently in fuel expense. KCP&L did not record any gains or losses due to ineffectiveness for the years ended December 31, 2004, 2003 or 2002. When the natural gas is purchased, the amounts in OCI are reclassified to fuel expense in the consolidated income statement.

Strategic Energy maintains a commodity-price risk management strategy that uses forward physical energy purchases and other derivative instruments to reduce the effects of fluctuations on purchased power expense caused by commodity-price volatility. Derivative instruments are used to limit the unfavorable effect that price increases will have on electricity purchases, effectively fixing the future purchase price of electricity for the applicable forecasted usage and protecting Strategic Energy from significant price volatility. The maximum term over which Strategic Energy is hedging its exposure and variability of future cash flows is 3.1 years and 3.0 years at December 31, 2004 and 2003, respectively.

Certain forward fixed price purchases and swap agreements are designated as cash flow hedges. The fair values of these instruments are recorded as assets or liabilities with an offsetting entry to OCI for the effective portion of the hedge. To the extent the hedges are not effective, the ineffective portion of the change in fair market value is recorded currently in purchased power. When the forecasted purchase is completed, the amounts in OCI are reclassified to purchased power. Purchased power for the year ended December 31, 2004, includes a $3.2 million gain due to ineffectiveness of the cash flow hedges. Strategic Energy did not record any gains or losses due to ineffectiveness for the years ended December 31, 2003 or 2002.

In 2003, Strategic Energy terminated an agreement with a swap counterparty due to credit and performance concerns. Strategic Energy received a $4.8 million fair value settlement. The swap was designated as a cash flow hedge of a forecasted transaction and Strategic Energy management believed the forecasted transaction would occur. Accordingly, the $4.8 million settlement was reclassified to purchased power expense over the remaining term of the underlying transaction, which was completed in 2003.

Strategic Energy also enters into economic hedges (non-hedging derivatives) that do not qualify for hedge accounting. The changes in the fair value of these derivative instruments recorded into net income as a component of purchased power were a $1.5 million loss and an insignificant gain for the years ended December 31, 2004 and 2003, respectively.

The notional and estimated fair values of the Company's derivative instruments are summarized in the following table as of December 31. The fair values of these derivatives are recorded on the consolidated balance sheets as of December 31, 2004 and 2003, respectively.

	2004		2003	
	Notional Contract Amount	**Fair Value**	**Notional Contract Amount**	**Fair Value**
Great Plains Energy	(millions)			
Swap contracts				
Cash flow hedges	$ 92.4	$ 4.5	$ 67.3	$ (0.8)
Non-hedging derivatives	2.3	0.7	-	-
Forward contracts				
Cash flow hedges	23.0	1.6	25.8	1.0
Non-hedging derivatives	5.5	(2.2)	1.3	-
Consolidated KCP&L				
Swap contracts				
Cash flow hedges	6.3	(0.3)	2.9	0.1

The amounts recorded in accumulated OCI related to the cash flow hedges are summarized in the following table.

	Great Plains Energy December 31		Consolidated KCP&L December 31	
	2004	2003	2004	2003
	(millions)			
Current assets	$ 2.5	$ 2.7	$ (0.3)	$ 0.1
Other deferred charges	0.9	0.8	-	-
Other current liabilities	(0.5)	(2.6)	-	-
Deferred income taxes	(0.8)	(0.2)	0.2	-
Other deferred credits	(0.9)	(0.4)	-	-
Total	$ 1.2	$ 0.3	$ (0.1)	$ 0.1

The amounts recorded in current assets and liabilities reflected in accumulated OCI in the table above as of December 31, 2004, are expected to be reclassified to expenses during the next twelve months for Great Plains Energy and consolidated KCP&L.

The amounts reclassified to revenues and expenses in 2004, 2003 and 2002 are summarized in the following table.

	Great Plains Energy			Consolidated KCP&L		
	2004	2003	2002	2004	2003	2002
	(millions)					
Gas revenues	$ -	$ -	$ 0.2	$ -	$ -	$ -
Fuel expense	(0.7)	(0.8)	(0.1)	(0.7)	(0.8)	(0.1)
Purchased power expense	(0.6)	(9.0)	5.4	-	-	-
Minority interest	0.2	1.0	(0.9)	-	-	-
Income taxes	0.5	3.8	(2.0)	0.3	0.3	0.1
OCI	$ (0.6)	$ (5.0)	$ 2.6	$ (0.4)	$ (0.5)	$ -

22. JOINTLY OWNED ELECTRIC UTILITY PLANTS

KCP&L's share of jointly owned electric utility plants as of December 31, 2004, is detailed in the following table.

	Wolf Creek Unit	LaCygne Units	Iatan Unit
	(millions, except MW amounts)		
KCP&L's share	47%	50%	70%
Utility plant in service	$ 1,366	$ 322	$ 260
Accumulated depreciation	671	236	183
Nuclear fuel, net	36		
KCP&L's accredited capacity--MWs	548	681	469

Each owner must fund its own portion of the plant's operating expenses and capital expenditures. KCP&L's share of direct expenses is included in the appropriate operating expense classifications in the Great Plains Energy and consolidated KCP&L Statements of Income.

23. QUARTERLY OPERATING RESULTS (UNAUDITED)

Great Plains Energy	Quarter 1st	2nd	3rd	4th
2004	(millions, except per share amounts)			
Operating revenue	$ 541.5	$ 613.5	$ 714.8	$ 594.2
Operating income	62.6	82.3	125.5	48.4
Income from continuing operations	29.5	41.4	67.9	34.7
Net income	27.3	41.6	75.9	36.0
Basic and diluted earning per common share from continuing operations	0.42	0.59	0.91	0.46
Basic and diluted earning per common share	0.39	0.59	1.02	0.48
2003				
Operating revenue	$ 464.2	$ 503.0	$ 660.8	$ 520.0
Operating income	58.7	90.9	166.9	50.8
Income from continuing operations	22.0	59.0	84.2	24.5
Net income (loss)	14.5	50.9	83.8	(4.3)
Basic and diluted earning per common share from continuing operations	0.31	0.85	1.21	0.34
Basic and diluted earning (loss) per common share	0.20	0.73	1.20	(0.07)

Consolidated KCP&L	Quarter 1st	2nd	3rd	4th
2004	(millions)			
Operating revenue	$ 247.0	$ 275.0	$ 323.7	$ 245.9
Operating income	49.7	68.3	111.3	37.8
Net income	21.2	32.3	63.9	25.9
2003				
Operating revenue	$ 234.9	$ 247.9	$ 350.7	$ 223.5
Operating income	42.8	53.9	148.5	36.3
Income from continuing operations	13.1	22.0	78.5	12.3
Net income	11.9	14.5	78.5	12.3

Quarterly data is subject to seasonal fluctuations with peak periods occurring in the summer months.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
Great Plains Energy Incorporated

We have audited the accompanying consolidated balance sheets of Great Plains Energy Incorporated and subsidiaries (the "Company") as of December 31, 2004 and 2003, and the related consolidated statements of income, comprehensive income, common stock equity and cash flows for each of the three years in the period ended December 31, 2004. Our audits also included the financial statement schedules listed in the Index at Item 15. These financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedules based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Great Plains Energy Incorporated and subsidiaries as of December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly in all material respects the information set forth therein.

As discussed in Note 5 to the consolidated financial statements, effective January 1, 2002, the Company changed its method of accounting for intangible assets to adopt Statement of Financial Accounting Standards ("SFAS") No. 142, "Goodwill and Other Intangible Assets". As discussed in Notes 1 and 16, respectively, to the consolidated financial statements, effective January 1, 2003, the Company changed its method of accounting for stock-based compensation to adopt SFAS No. 123, "Accounting for Stock-Based Compensation" and changed its method of accounting for asset retirement obligations to adopt SFAS No. 143, "Accounting for Asset Retirement Obligations".

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of December 31, 2004, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 4, 2005, expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/DELOITTE & TOUCHE LLP

Kansas City, Missouri
March 4, 2005

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Kansas City Power & Light Company

We have audited the accompanying consolidated balance sheets of Kansas City Power & Light Company and subsidiaries (the "Company") as of December 31, 2004 and 2003, and the related consolidated statements of income, comprehensive income, common stock equity and cash flows for each of the three years in the period ended December 31, 2004. Our audits also included the financial statement schedules listed in the Index at Item 15. These financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedules based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, 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 City Power & Light and subsidiaries as of December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly in all material respects the information set forth therein.

As discussed in Note 5 to the consolidated financial statements, effective January 1, 2002, the Company changed its method of accounting for intangible assets to adopt Statement of Financial Accounting Standards ("SFAS") No. 142, "Goodwill and Other Intangible Assets". As discussed in Note 16 to the consolidated financial statements, effective January 1, 2003, the Company changed its method of accounting for asset retirement obligations to adopt SFAS No. 143, "Accounting for Asset Retirement Obligations".

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of December 31, 2004, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 4, 2005, expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/DELOITTE & TOUCHE LLP

Kansas City, Missouri
March 4, 2005

CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of the effectiveness of internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Great Plains Energy

Management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934, as amended) for Great Plains Energy. Under the supervision and with the participation of Great Plains Energy's chief executive officer and chief financial officer, management evaluated the effectiveness of Great Plains Energy's internal control over financial reporting as of December 31, 2004. Management used for this evaluation the framework in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations (COSO) of the Treadway Commission. Management has concluded that, as of December 31, 2004, Great Plains Energy's internal control over financial reporting is effective based on the criteria set forth in the COSO framework. Deloitte & Touche, LLP, the independent registered public accounting firm that audited the financial statements included in this Annual Report, has issued its audit report on this assessment, which is included below.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
Great Plains Energy Incorporated

We have audited management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that Great Plains Energy Incorporated and subsidiaries (the "Company") maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedules as of and for the year ended December 31, 2004, of the Company and our report dated March 4, 2005, expressed an unqualified opinion on those financial statements and financial statement schedules.

/s/DELOITTE & TOUCHE LLP

Kansas City, Missouri
March 4, 2005

KCP&L

Management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 15d-15(f) under the Securities Exchange Act of 1934, as amended) for KCP&L. Under the supervision and with the participation of KCP&L's chief executive officer and chief financial officer, management evaluated the effectiveness of KCP&L's internal control over financial reporting as of December 31, 2004. Management used for this evaluation the framework in *Internal Control – Integrated Framework* issued by the COSO of the Treadway Commission. Management has concluded that, as of December 31, 2004, KCP&L's internal control over financial reporting is effective based on the criteria set forth in the COSO framework. Deloitte & Touche, LLP, the independent registered public accounting firm that audited the financial statements included in this Annual Report, has issued its audit report on this assessment, which is included below.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Kansas City Power & Light Company

We have audited management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that Kansas City Power & Light Company and subsidiaries (the "Company") maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedules as of and for the year ended December 31, 2004, of the Company and our report dated March 4, 2005, expressed an unqualified opinion on those financial statements and financial statement schedules.

/s/DELOITTE & TOUCHE LLP

Kansas City, Missouri
March 4, 2005

CERTIFICATIONS

I, Michael J. Chesser, certify that:

1. I have reviewed this annual report on Form 10-K of Great Plains Energy Incorporated;

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)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) 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) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the 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 the 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 7, 2005

/s/Michael J. Chesser
Michael J. Chesser
Chairman of the Board and Chief Executive Officer

CERTIFICATIONS

I, Andrea F. Bielsker, certify that:

1. I have reviewed this annual report on Form 10-K of Great Plains Energy Incorporated;

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)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) 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) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the 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 the 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 7, 2005

/s/Andrea F. Bielsker

Andrea F. Bielsker
Senior Vice President - Finance, Chief Financial Officer and Treasurer

Continued from inside front cover

As a leader on economic growth and energy issues, Great Plains Energy helps light the way for our communities.

Low Income Assistance

Working closely with dedicated professionals in non-profit and public agencies, KCP&L helps find ways to deliver affordable energy to every household, including area residents who need assistance paying their energy bills.

Collaboration Leads to Progress

Our philosophy is to collaborate with community leaders to get things done. From governors, on to legislatures and city councils, and out into the neighborhoods we serve, we work hard to listen, join in the public dialogue, and collaborate for innovative solutions.

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KEPCo annual report

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2004 KEPCo Annual Report

KEPCo

Organization & Resources

Kansas Electric Power Cooperative, Inc. (KEPCo), headquartered at Topeka, Kansas, was incorporated in 1975 as a not-for-profit generation and transmission cooperative (G&T). It is KEPCo's responsibility to procure an adequate and reliable power supply for its nineteen distribution Rural Electric Cooperative Members at a reasonable cost.

Through their combined resources, KEPCo Members support a wide range of other services such as rural economic development, marketing and diversification opportunities, power requirement and engineering studies, rate design, etc.

KEPCo is governed by a Board of Trustees representing each of its nineteen Members which collectively serve more than 100,000 electric meters in two-thirds of rural Kansas. The KEPCo Board of Trustees meets regularly to establish policies and act on issues that often include recommendations from working committees of the Board and KEPCo Staff. The Board also elects a seven-person Executive Committee which includes the President, Vice President, Secretary, Treasurer, and three additional Executive Committee members.

KEPCo is under the jurisdiction of the Kansas Corporation Commission (KCC) and was granted a limited certificate of convenience and authority in 1980 to act as a G&T public utility. KEPCo's power supply resources consist of: 70 MW of owned generation from the Wolf Creek Generating Station; the 20 MW Sharpe Generating Station located in Coffey County; hydropower purchases of an equivalent 100 MW from the Southwestern Power Administration, and 14 MW from the Western Area Power Administration; plus partial requirement power purchases from regional utilities.

KEPCo is a Touchstone Energy® Cooperative. Touchstone Energy® is a nationwide alliance of more than 600 cooperatives committed to promoting the core strengths of electric cooperatives – integrity, accountability, innovation, personal service and a legacy of community commitment. The national program is anchored by the motto "The Power of Human Connections."

Kansas Electric
Power Cooperative, Inc.
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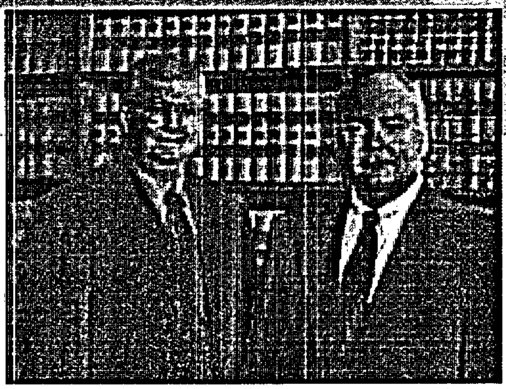
(785) 273-7010 www.kepco.org

2004 Message


Mr. Maginley and Mr. Parr

from
Kenneth J. Maginley,
KEPCo President

Stephen E. Parr,
Executive Vice President
& Chief Executive Officer

Sometimes a single year can't be neatly packaged into a series of highlights or words of wisdom and inspiration. Sometimes the work of an organization is focused on larger efforts that are not defined within 12 neat monthly periods. 2004 was such a year.

While the year precedes the anniversary of KEPCo's charter 30 years ago, most days, and many evenings, were more appropriately focused on the future rather than reflection. Nevertheless, a brief salute to our history would be in order and perhaps inspirational. On February 13, 1975, six rural Kansas leaders filed papers to incorporate the Kansas Electric Power Cooperative, Inc. (KEPCo). Their mission was to gain control of power supply and transmission issues by owning and operating a G&T Cooperative.

"These challenges are nothing new and history proves that they will be met most effectively through our cooperative efforts. Member unity was necessary to provide the clout to organize KEPCo. That common bond has been equally important in order to develop and provide a reliable electric supply through three decades. Unity and cooperation will be even more important as we prepare for changes ahead."

Those visionary individuals were followed by a series of Cooperative leaders who demonstrated determination and a will to succeed that was nothing short of heroic. KEPCo's development overcame regulatory and legislative obstacles, endured litigation, weathered nuclear, hydropower and other generation and transmission challenges, and confronted financial impediments such as record high interest rates. History shows that there were many times when Members did not agree on an issue but recognized the importance of cooperation and that KEPCo would work best — when it worked together.

KEPCo continues to have such leaders on the Board of Trustees — leaders who combine a respect for that history with a commitment to meet the challenges facing KEPCo in the future. Working to meet those challenges best defines the year 2004.

The cornerstone of KEPCo's continuing ability to fashion a stable and economical power supply for its Members is a new Member Wholesale Power Agreement that better fits the 21st Century. New contracts will permit some power supply flexibility for our Members, as well as provide KEPCo with the lending security necessary for existing debt and to consider future resource acquisitions.

With resolve, the KEPCo Board reviewed contract provisions and language during the year and a series of workshops continue toward development of suitable language. Member support for a new contract will guide the development of KEPCo's power supply to meet demand over the next 30 years.

Numerous other major efforts went on simultaneously to contract development. The KEPCo Board approved a Long Range Resource Plan, independently developed by consultants Burns and McDonnell, which states clear objectives for meeting our power supply needs in a cost effective and limited risk manner. The study calls for KEPCo to seek an extension of the Wolf Creek Generating Station operating license in order to maximize this significant generating resource. It also calls for KEPCo to secure approximately 100 MW of coal-fired generation and extend existing power purchase contracts with regional utilities.

Steps to implement that plan were taken immediately. Work is underway, in cooperation with the other owners of Wolf Creek, to seek a license extension from the Nuclear Regulatory Commission. KEPCo is also meeting with regional utilities to evaluate power supply contract opportunities. These efforts continue to proceed with promise.

Developing its Long Range Resource Plan served to reinforce KEPCo's long-standing belief that future power supply needs may best be served by pursuing ownership and control of our own generation. New generation facilities have been announced by several utilities in the region and KEPCo continues to meet with principal developers to review opportunities for participation. The last coal generation facility in Kansas was built more than 20 years ago and plans for new generation in the region are quickly developing.

In order for KEPCo to participate in generation opportunities we must be in a position to initially finance and maintain status as a strong partner through the life of a new plant. That strength lies in the assurance of Member support for KEPCo through commitment to a new wholesale power contract.

Preparation of that contract will continue into 2005, as will related work on accompanying bylaw and policy changes, financing options, contract negotiations and other steps to prepare for the future.

Meanwhile, we want to recognize and applaud the day-to-day efforts of our staff to provide power supply and other professional services to our Member Cooperatives. Many of those accomplishments are detailed in this Annual Report. They include the successful refinancing of eligible KEPCo debt, ongoing emphasis on power quality, reliability, engineering

(continued on page 15)

Melroy Kopsa Completes Four Years of Service as President

One of the most significant events in 2004 was Melroy Kopsa's conclusion of service as President of the KEPCo Board of Trustees. His leadership as President began in November 2000 and he stood for successful re-election three subsequent years. Part of Mr. Kopsa's remarks to the KEPCo Annual Meeting on November 2004 are reprinted below.

"When I decided not to seek re-election, I began to reflect on the past four years and believe we have reasons to be proud and thankful. We've seen energy prices skyrocket to more than $7 for natural gas and over $50 a barrel for oil and the effect of energy prices and other factors on our economy.

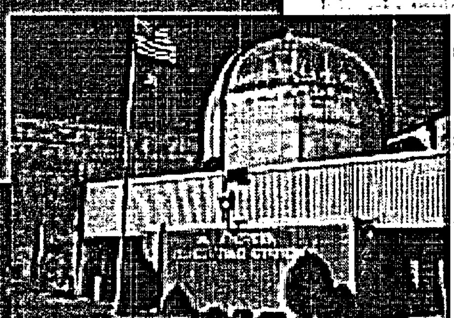
"In our industry, we've witnessed the collapse of Enron and misdeeds at utilities closer to home. We've seen a colossal energy

'04

Highlights

In January, the KEPCo Finance Department established a Cushion of Credit account in the Rural Electric and Telephone (RET) loan system. This program enables KEPCo to deposit funds that are then made available to meet scheduled payments to the Federal Financing Bank (FFB). KEPCo receives 5% interest on these advance payments. This program allowed KEPCo to recognize an additional $200,000 in interest income in 2004.

KEPCo's Engineering and Operations Department continues to concentrate on the maintenance of metering, SCADA and communications to over 300 delivery points and individual sites across the state of Kansas. Accurate and dependable metering and communications are vital to KEPCo operations.



The Wolf Creek Generating Station

KEPCo owns six percent of the Wolf Creek Generating Station. Wolf Creek, an 1170 MW nuclear plant, is located near Burlington, in Coffey County, KS. The plant has an outstanding record of operating and safety excellence dating back to the start of commercial operation on September 3, 1985. In 2004, Wolf Creek implemented a number of security enhancements as a result of Homeland Security mandates, completed the year with no serious accidents and received a positive safety assessment by the Nuclear Regulatory Commission.

KEPCo Operations and Maintenance Staff worked on maintenance of instrument transformers, meters, and communications at 80 meter locations during the year. Staff also maintained 290 RTUs along with communications consisting of 2.4 GHz radios, 900 MHz radios, 220 MHz radios, and frame-relay lease circuits. In addition to other normal maintenance functions, Staff participated in significant projects such as the installation of a new 34.5 kV delivery point for Victory Electric Cooperative to support a new industrial load and a joint project with Ninnescah Electric Cooperative to install voltage regulators at an industrial facility. Department employees traveled over 120,000 miles during the year to meet Member needs.

An Inter Control-center Communication Protocol (ICCP) connection was added between KEPCo and Empire via the Southwest Power Pool (SPP). The ICCP allows an exchange of information to support KEPCo's energy contracts with Westar Energy and the Southwestern Power Administration.

KEPCo

Several KEPCo Staff members are serving in leadership roles in state and federal industry related associations and groups. Harold Haun serves as President of the National G&T Lawyers Association. Loren Medley is Past President of the National Rural Economic Developers Association and is President of the Kansas Rural Development Council. Bruce Graham is President of NRECA's Council of Rural Electric Communicators (CREC). Bill Goshorn is active in hydropower customer groups for both WAPA and SWPA and currently serves as Chairman of the SPRA Federal Power Marketing Committee.

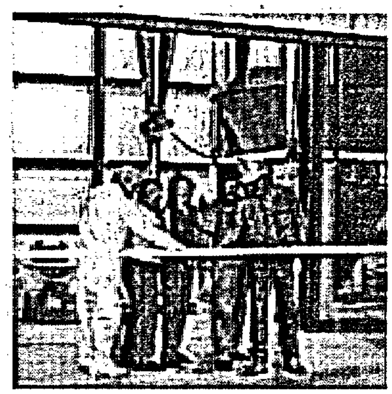
KEPCo continued to fund and assist Members in promotion of an electric water heater and heating system rebate program. Since the start of the rebate program, KEPCo has issued more than 11,000 water heater rebates and nearly 4,000 heating system rebates. Electricity is a safe, clean and competitively priced option and this program helps communicate that message.

The Legal Department has been engaged in discussions and drafting of new wholesale power contracts, new policies and changes in the KEPCo Bylaws in response to the effort to meet Member power supply needs to the year 2045. In addition, Harold Haun supported numerous projects including KEPCo's filings and responses to KCC Dockets as well as draft and approval of various KEPCo contracts, Board resolutions, policies, some Board committee minutes, and other legal documents. The Legal Department also leads administrative action on certain internal KEPCo policies and benefits.

KEPCo continued participation in Touchstone Energy and assisted in the organization of state events such as the Electric Cooperative Day at the State Fair and Kansas participation in the new economic development web site called SitesAcrossAmerica.com. Nationally, Touchstone Energy now includes more than 600 Cooperatives that benefit from service enhancements such as new employee training modules, the Co-op Connections loyalty card, the Get Charged education kit, Touchstone Energy Home, and other program additions.

Touchstone Energy®
The power of human connections

Below: An official ribbon cutting was held on September 20 to mark the successful expansion of Nutri-Shield, Inc. in Courtland, KS. Rolling Hills REC assisted with the project by securing a $136,000 zero-interest REDLG loan.



REDLG Loans Yield Success Stories

KEPCo and its Members are successful participants in USDA's Rural Economic Development Loan and Grant (REDLG) program. In 2004, five Members garnered $806,000 in zero interest loans for a variety of economic development projects. Over the years, the REDLG program has loaned or granted KEPCo Member projects $14.3 million and, when combined with the $38.3 million in project private investment, results in a rural development impact of $52.6 million. In addition, the projects increase property valuation and the 780 new jobs and associated wages improve regional prosperity.

KEPCo Services Inc. (KSI) marked its seventh year of operation in 2004. KSI Engineering, the principal operating activity of KEPCo Services, is now listed as the official engineering consultant for nine electric cooperatives. KSI has completed at least one project for each of KEPCo's Members and surpassed 100 completed projects to date. Through the last six years, KSI Engineering has earned more than $825,000 in revenues, has contributed $150,000 to KEPCo overheads, and developed a net margin of more than $15,000.

The 20 MW Sharpe Generating Station, located in Coffey County, KS, is owned by KEPCo and was declared operational in 2002. KEPCo and Martin Tractor Company work together to test and maintain generation capability in order to be able to operate the plant within a few minutes of being notified by Westar Energy.

KEPCo supports Member marketing efforts in a variety of ways. KEPCo serves as a key contact for Touchstone Energy programs in Kansas. In addition, KEPCo marketing Staff developed a series of advertisements for use in Kansas Country Living, displayed at ten Member annual meetings, and supported numerous individual Member projects. KEPCo Staff also worked with Members to utilize the Customer Information System for creation of more than 20,000 direct mail pieces promoting surge protection, security lights, load management, auto bank draft, levelized billing, DirecTV, annual meeting notices, electrical contracting services, electric water heaters, and heat pumps.

KEPCo Engineers have prioritized delivery point reliability by conducting field inspections, compiling reliability reports, and organizing multiple meetings with transmission providers in order to improve power quality.

KSI is your cooperative engineering and planning partner specializing in construction work plans, mapping, sectionalizing studies, financial forecasts, substation design, transmission design, work order inspections, power quality, demand side management, and substation spill prevention/control plans. This last year, KSI added the following to its list of services: line staking, GIS development and the preparation of transformer specifications. KSI Engineering provided design engineering and technical support for the construction of the 5 MVA Kaw Valley "K" Substation. KSI Engineering continues to help Member Cooperatives take advantage of the KEPCo SCADA communication infrastructure to monitor and control equipment at their substations. KSI Engineering now has both AutoCAD Map and ESRI GIS capabilities to meet any mapping or drawing need.

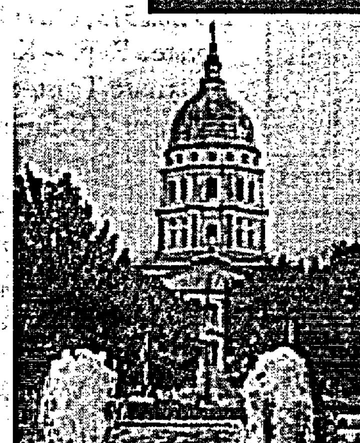
Hilda Legg visits the KEPCo office.

KEPCo hosted several VIPs during the year including a February breakfast with RUS Administrator Hilda Legg and a presentation to the KEPCo Board by SWPA Administrator Mike Deihl. KEPCo also makes its Board Room available to groups and organizations that have a business association. Many times, legislators and important state and federal officials are present at these events, raising awareness of KEPCo as a partner in important planning and development activities in Kansas.

Highlights '04

KEPCo's SCADA system anchored another successful load management season and Staff continues to improve the capabilities of the system-wide communication network. Enhancements include offering 3-line displays of each delivery point, better alarm handling by providing separate alarms for Members and KEPCo, and a greatly improved load estimating algorithm. Using the SCADA system, Staff can remotely start, operate and monitor the Sharpe Generating Station. Bluestem, Butler, Flint Hills, Heartland, Rolling Hills, and Sumner-Cowley Electric Cooperatives have Automated Meter Reading (AMR) using the SCADA Wide Area Network (WAN) to communicate to their Master Radio sites. DS&O has started its AMR project and quotes have been issued for AMR communication projects for CMS and Twin Valley.

KEPCo continues to work with Kansas Electric Cooperatives (KEC) and Sunflower Electric Power Corporation on legislative issues in Kansas and in Washington, D.C. KEPCo testified on six different bills in 2004 and tracked approximately 50 different pieces of legislation. In Congress, KEPCo participated in the NRECA Legislative Conference and a series of actions in response to NRECA calls on the federal energy bill, the Rural Economic Development Loan & Grant Program regulations, and other issues.



The Kansas Statehouse

Safety training continues to be essential for all employees at KEPCo. An Employee Safety Committee organized six mandatory meetings and one voluntary CPR/First Aid course during the year. Dating back to 1984, KEPCo employees have logged more than 850,000 hours without a lost-time accident.

KEPCo has been involved in a cross-section of community and associated activities in support of rural development. Staff participated in high profile events such as the Kansas Prosperity Summit and Congressional Listening Tours.

KEPCo's SCADA system scored another home run when it enabled KEPCo to begin scheduling SWPA hydropower into the Empire control area. Staff manages this procedure which allows KEPCo to take advantage of a contract that reduced purchases from a higher priced supplier. In addition, this creative solution was accomplished without investing approximately $30 million in transmission that the Southwest Power Pool determined was necessary to complete the power supply transaction.

KEPCo Member Cooperatives Trustees, Alternates and Managers


Dwight Engelland

Ark Valley Electric Cooperative Assn., Inc.
PO Box 1246, South Hutchinson, KS 67504 620-662-6661
Trustee Rep. -- Dwight Engelland
Alternate Trustee Rep. -- Bob Hall
Manager -- Bob Hall


Bob Hall


Ken Maginley

Bluestem Electric Cooperative, Inc.
PO Box 5, Wamego, KS 66547 785-456-2212
PO Box 513, Clay Center, KS 67432 785-632-3111
Trustee Rep. -- Kenneth J. Maginley
Alternate Trustee Rep. -- Robert Ohlde
Manager -- Kenneth J. Maginley


Bob Ohlde


Dale Bodenhausen

Brown-Atchison Electric Cooperative Assn., Inc.
PO Box 230, Horton, KS 66439 785-486-2117
Trustee Rep. -- Dale Bodenhausen
Alternate Trustee Rep. -- Kevin Compton
Manager -- Rodney V. Gerdes


Kevin Compton


Rod Gerdes


Bob Nichols

Butler Rural Electric Cooperative Assn., Inc.
PO Box 1242, El Dorado, KS 67042 316-321-9600
Trustee Rep. -- Bob Nichols
Alternate Trustee Rep. -- Dale Short
Manager -- Dale Short


Dale Short


Floyd Montgomery

Caney Valley Electric Cooperative Assn., Inc.
PO Box 308, Cedar Vale, KS 67024 620-758-2262
Trustee Rep. -- Floyd Montgomery
Alternate Trustee Rep. -- Allen A. Zadorozny
Manager -- Allen A. Zadorozny


Allen Zadorozny

Kirk Thompson

CMS Electric Cooperative, Inc.
PO Box 790, Meade, KS 67864 620-873-2184
Trustee Rep. -- Kirk A. Thompson
Alternate Trustee Rep. -- Clifford Friesen
Manager -- Kirk A. Thompson

Cliff Friesen

Harlow Haney

DS&O Rural Electric Cooperative Assn., Inc.
PO Box 286, Solomon, KS 67480 785-655-2011
Trustee Rep. -- Harlow Haney
Alternate Trustee Rep. -- Don Hellwig
Manager -- Don Hellwig

Don Hellwig

Bob Reece

Flint Hills Rural Electric Cooperative Assn., Inc.
PO Box B, Council Grove, KS 66846 620-767-5144
Trustee Rep. -- Robert E. Reece
Alternate Trustee Rep. -- Gus Hamm
Manager -- Robert E. Reece

Gus Hamm

Dennis Peckman

Heartland Rural Electric Cooperative, Inc.
PO Box 40, Girard, KS 66743 620-724-8251
District Offices, Iola 620-365-5151
Mound City, 913-795-2221
Trustee Rep. -- Dennis Peckman
Alternate Trustee Rep. -- Dale Coomes
Manager -- Dale Coomes

Dale Coomes

Robert Smith, Jr.

Leavenworth-Jefferson Electric Cooperative, Inc.
PO Box 70, McLouth, KS 66054 913-796-6111
Trustee Rep. -- Robert Smith, Jr.
Alternate Trustee Rep. -- H.B. Canida
Manager -- H.B. Canida

H.B Canida

2004-05 KEPCo Executive Committee

Officers
President: Kenneth Maginley
Vice President: Larry Scott
Secretary: Gordon Coulter
Treasurer: Bryan Coover

Executive Committee Members
Dwight Engelland
Melroy Kopsa
David Reichenberger

KEPCo Member Cooperatives Trustees, Alternates and Managers


Larry Scott

Lyon-Coffey Electric Cooperative, Inc.
PO Box 229, Burlington, KS 66839 620-364-2116
Trustee Rep. -- Larry Scott
Alternate Trustee Rep. -- Donna Williams
Manager -- Larry Scott


Donna Williams


Gordon Coulter

Ninnescah Electric Cooperative Assn., Inc.
PO Box 967, Pratt, KS 67124 620-672-5538
Trustee Rep. -- Gordon Coulter
Alternate Trustee Rep. -- Carla Bickel
Manager -- Carla Bickel


Carla Bickel


Gilbert Berland

Prairie Land Electric Cooperative, Inc.
PO Box 360, Norton, KS 67654 785-877-3323
District Office, Bird City 785-734-2311
Trustee Rep. -- Gilbert Berland
Alternate Trustee Rep. -- Allan J. Miller
Manager -- Allan J. Miller


Allan Miller


Dennis Duft

Radiant Electric Cooperative, Inc.
PO Box 390, Fredonia, KS 66736 620-378-2161
Trustee Rep. -- Dennis Duft
Alternate Trustee Rep. -- Tom Ayers
Administrative Manager -- Leah Tindle
Operations Manager -- Dennis Duft


Tom Ayers


Leah Tindle


Melroy Kopsa

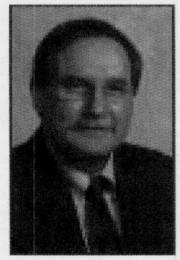
Rolling Hills Electric Cooperative, Inc.
PO Box 307, Mankato, KS 66956 785-378-3151
District Offices, Belleville 785-527-2251
Ellsworth 785-472-4021
Trustee Rep. -- Melroy Kopsa
Alternate Trustee Rep. -- Leon Eck
Manager -- Douglas J. Jackson


Leon Eck

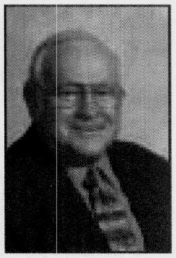

Doug Jackson

David Reichenberger

Sedgwick County
Electric Cooperative Assn., Inc.
PO Box 220, Cheney, KS 67025 316-542-3131
Trustee Rep. -- David Reichenberger
Alternate Trustee Rep. -- Alan L. Henning
Manager -- Alan L. Henning

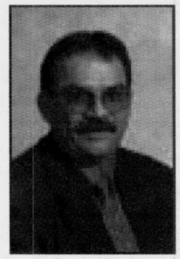


Alan Henning

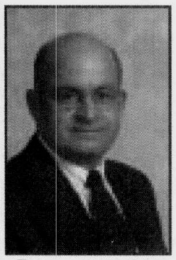


Charles Riggs

Sumner-Cowley Electric Cooperative, Inc.
PO Box 220, Wellington, KS 67152 620-326-3356
Trustee Rep. -- Charles Riggs
Alternate Trustee Rep. -- Cletas Rains
Manager -- Cletas Rains

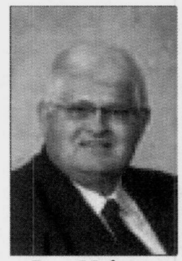


Cletas Rains

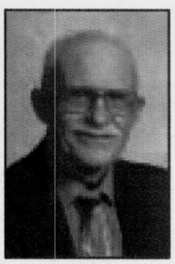


Bryan Coover

Twin Valley Electric Cooperative, Inc.
PO Box 385, Altamont, KS 67330 620-784-5500
Trustee Rep. -- Bryan Coover
Alternate Trustee Rep. -- Ron Holsteen
Manager -- Ron Holsteen

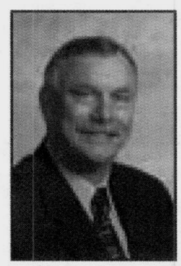


Ron Holsteen

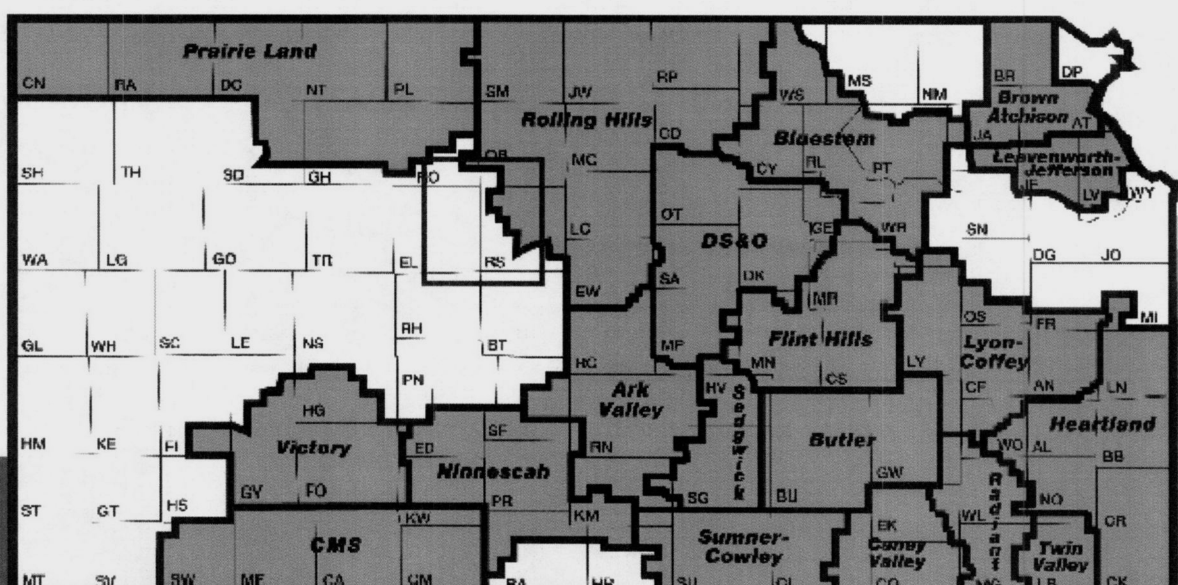


Marvin Hampton

Victory Electric Cooperative Assn., Inc.
PO Box 1335, Dodge City, KS 67801 620-227-2139
Trustee Rep. -- Marvin Hampton
Alternate Trustee Rep. -- Terry Janson
Manager -- Terry Janson



Terry Janson



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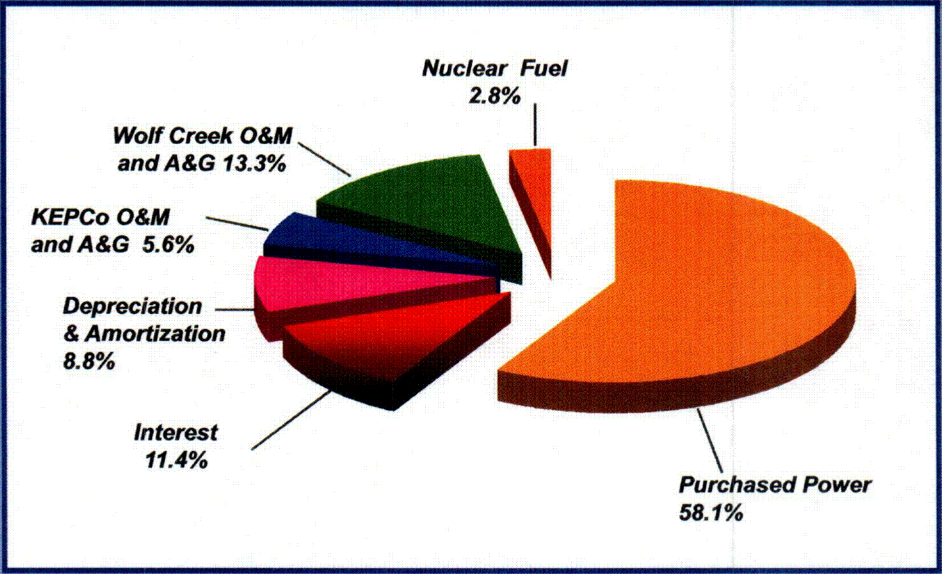
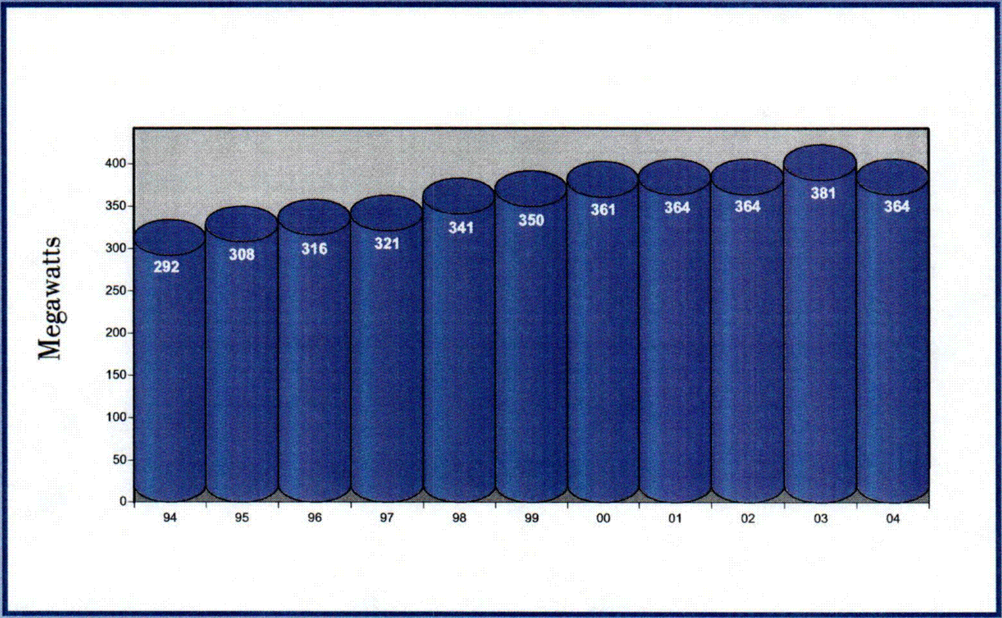
Operating Statistics

Operating Expenses



Peak Demand



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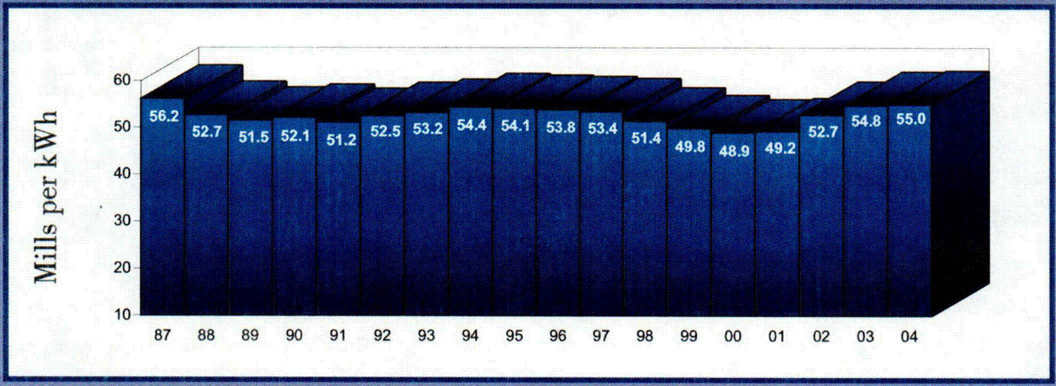
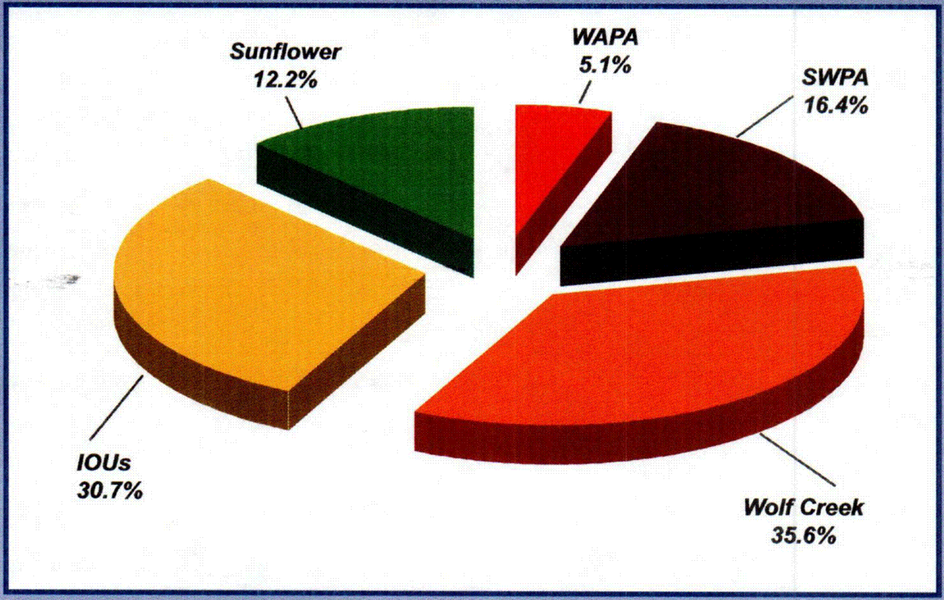
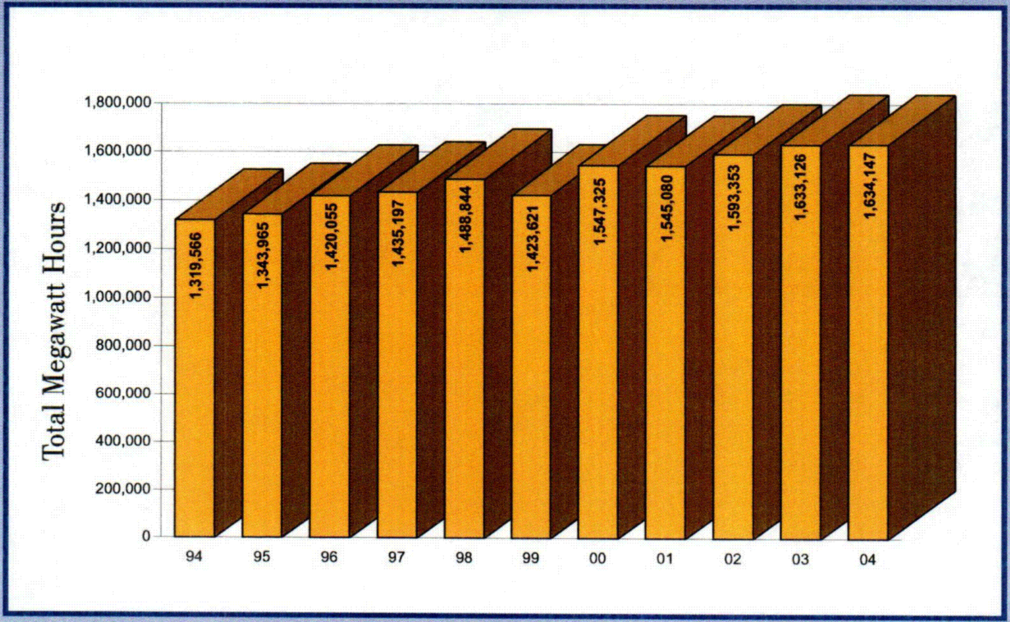
Rates



Sources of Energy



Energy Sales



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market disaster in California and a transmission system breakdown that caused a black-out in the Northeast United States. Power supply markets and transmission issues are unsettled across the nation and will take years to resolve.

"Through it all, KEPCo stayed steady. We protected Members from the volatility of the energy market for several years, saving them nearly 40 million dollars," he said. Mr. Kopsa acknowledged that fuel costs, weather and other factors eventually combined to require a rate increase in February 2002. However, because of that market volatility, Mr. Kopsa may best be remembered for his leadership in the Board's strategic decision to work toward increasing control and management of generation resources.

As a result, on July 18, 2002, the KEPCo Board of Trustees proudly dedicated the 20 megawatt Sharpe Generating Station. In addition, KEPCo installed an EMS/SCADA system to provide load control, power supply scheduling, communication and other services.

Efforts continue toward a more cost-based rate rather than market-based risk under the new leadership of Mr. Kenneth Maginley, who was elected KEPCo President on November 18, 2004. Mr. Maginley is Manager of Bluestem Electric Cooperative, headquartered in Wamego.

"Since I joined the Electric Cooperative family in 1977, I have witnessed and been part of the evolution of KEPCo. I appreciate the Board's confidence in electing me President and with that I accept the responsibility of working with the Board to prepare KEPCo for the future," said Mr. Maginley.

The KEPCo Board of Trustees elected its Executive Committee during the November 18, 2004 Meeting. Executive Committee Members: front row (left to right): Melroy Kopsa, David Reichenberger, and Dwight Engelland; Back row (left to right): Kenneth Maginley, President; Larry Scott, Vice President; Bryan Coover, Treasurer; Gordon Coulter, Secretary; and Stephen E. Parr, Executive Vice President and CEO.

and operational services, effective government affairs, marketing and rural development, and a growing KEPCo Services, Inc.

To succeed in life, a person must often readjust to their surroundings. That is also true for KEPCo and its Member Cooperatives. Power supply, contract evaluation and negotiations, maintenance and operations, along with other Member services require our primary attention. New generation opportunities, transmission changes, potential asset acquisitions, and other challenges require more effort and adjustment.

These challenges are nothing new and history proves that they will be met most effectively through our cooperative efforts. Member unity was necessary to provide the clout to organize KEPCo. That common bond has been equally important in order to develop and provide a reliable electric supply through three decades. Unity and cooperation will be even more important as we prepare for changes ahead.

Kenneth J. Maginley
President

Stephen E. Parr
Executive Vice President and CEO

Financial Statements

December 31, 2004 and 2003 with Independent Auditors' Report Thereon

KPMG LLP
Suite 1000
1000 Walnut Street
Kansas City, MO 64106-2162

The Board of Trustees
Kansas Electric Power Cooperative, Inc.:

We have audited the accompanying consolidated balance sheets of Kansas Electric Power Cooperative, Inc. and subsidiaries (KEPCo) as of December 31, 2004 and 2003, and the related consolidated statements of revenues and expenses, cash flows, and changes in patronage capital for the years then ended. These consolidated financial statements are the responsibility of KEPCo's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

As more fully described in note 4 to the consolidated financial statements, certain depreciation and amortization methods have been used in the preparation of the consolidated financial statements that do not, in our opinion, conform to accounting principles generally accepted in the United States of America.

In our opinion, except for the effects on the consolidated financial statements of the matters referred to in the preceding paragraph, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of KEPCo as of December 31, 2004 and 2003, and the results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

As discussed in note 2 to the consolidated financial statements, on January 1, 2003, KEPCo adopted Statement of Accounting Standards No. 143, *Accounting for Asset Retirement Obligations.*

In accordance with *Government Auditing Standards*, we have also issued a report dated March 11, 2005, on our consideration of KEPCo's internal control over financial reporting and our tests of its compliance with certain provisions of laws, regulations, contacts, and grant agreements and other matters. The purpose of that report is to describe the scope of our testing of internal control over financial reporting and compliance and the results of that testing, and not to provide an opinion on the internal control over financial reporting or on compliance. That report is an integral part of an audit performed in accordance with *Government Auditing Standards* and should be considered in assessing the results of our audit.

KPMG LLP

Kansas City, Missouri
March 11, 2005

Consolidated Balance Sheets

December 31, 2004 and 2003

Assets	2004	2003
Utility plant:		
In-service	$ 223,290,771	223,111,948
Less allowances for depreciation	(114,279,455)	(111,796,459)
Net in-service	109,011,316	111,315,489
Construction work in progress	1,801,777	1,172,065
Nuclear fuel, net of amortization	4,558,431	3,693,512
Total utility plant	115,371,524	116,181,066
Restricted assets:		
Investments in the National Rural Utilities Cooperative Finance Corporation	3,323,052	3,318,093
Bond fund reserve	4,230,261	4,193,570
Decommissioning fund	7,165,662	6,089,845
Investments in other associated organizations	84,040	59,129
Total restricted assets	14,803,015	13,660,637
Current assets:		
Cash and cash equivalents	5,229,724	8,226,833
Member accounts receivable	7,332,176	7,220,772
Materials and supplies	2,785,126	2,658,146
Other assets and prepaid expenses	608,221	532,203
Total current assets	15,955,247	18,637,954
Other long-term assets:		
Deferred charges:		
Wolf Creek disallowed costs (less accumulated amortization of $9,606,405 and $8,849,243 for 2004 and 2003, respectively)	16,376,515	17,133,678
Wolf Creek deferred plant costs (less accumulated amortization of $9,389,759 and $6,259,839 for 2004 and 2003, respectively)	37,559,034	40,688,954
Wolf Creek decommissioning regulatory asset	3,088,274	3,349,999
Deferred Department of Energy decommissioning costs	254,597	338,199
Deferred incremental outage costs	831,829	2,793,858
Other deferred charges (less accumulated amortization of $1,252,185 and $1,087,234 for 2004 and 2003, respectively)	1,245,506	1,410,457
Unamortized debt issuance costs	4,749,145	5,417,944
Other investments	178,447	173,976
Total long-term assets	64,283,347	71,307,065
Total assets	$ 210,413,133	219,786,722

KEPCo

Consolidated Balance Sheets

December 31, 2004 and 2003

Patronage Capital and Liabilities	2004	2003
Patronage capital:		
Memberships	$ 3,200	3,200
Patronage capital (payment restricted as indicated)	14,998,948	11,812,345
Total patronage capital	15,002,148	11,815,545
Long-term debt:		
National Rural Utilities Cooperative Finance Corporation	4,832,764	5,267,017
Federal Financing Bank	86,909,257	96,295,154
Grantor Trust Series 1997	47,740,000	49,640,000
Pollution control revenue bonds	30,100,000	31,700,000
Total long-term debt	169,582,021	182,902,171
Less current maturities of long-term debt	(9,953,205)	(9,112,155)
Long-term debt, net of current maturities	159,628,816	173,790,016
Other long-term liabilities:		
Deferred Department of Energy decommissioning costs	185,161	270,559
Wolf Creek decommissioning liability	13,128,504	12,385,380
Wolf Creek nuclear operating liabilities	2,298,001	2,225,422
Arbitrage rebate long-term liability	801,948	585,092
Other deferred credits	2,262	925
Total other long-term liabilities	16,415,876	15,467,378
Current liabilities:		
Current maturities of long-term debt	9,953,205	9,112,155
Accounts payable	7,466,081	6,438,669
Payroll and payroll-related liabilities	266,134	245,540
Accrued property taxes	1,310,783	1,290,654
Accrued interest payable	370,090	1,626,765
Total current liabilities	19,366,293	18,713,783
Total patronage capital and liabilities	$ 210,413,133	219,786,722

See accompanying notes to consolidated financial statements.

Statements of Revenues and Expenses

December 31, 2004 and 2003

		2004	2003
Operating revenues:			
Sales of electric energy	$	89,827,520	89,424,340
Other		634,802	411,162
Total operating revenues		90,462,322	89,835,502
Operating expenses:			
Power purchased		51,029,353	50,371,152
Nuclear fuel		2,442,098	2,149,674
Plant operations		8,698,938	8,559,578
Plant maintenance		2,867,437	2,839,025
Administrative and general		4,574,684	4,374,015
Amortization of deferred charges		4,052,034	4,057,683
Depreciation and decommissioning		4,261,130	4,353,980
Total operating expenses		77,925,674	76,705,107
Net operating revenues		12,536,648	13,130,395
Interest and other deductions:			
Interest on long-term debt		9,239,290	10,904,171
Amortization of debt issuance costs		668,799	454,861
Other deductions		47,306	44,997
Total interest and other deductions		9,955,395	11,404,029
Operating income		2,581,253	1,726,366
Other income (expense):			
Interest income		621,143	423,963
Other expense		(15,793)	(22,226)
Total other income		605,350	401,737
Net margin	$	3,186,603	2,128,103

See accompanying notes to consolidated financial statements.

Statements of Changes in Patronage Capital

December 31, 2004 and 2003

		Memberships	Patronage capital	Unallocated margin (loss)	Total
Balance, December 31, 2002	$	3,200	11,801,741	(2,117,499)	9,687,442
Net margin		—	10,604	2,117,499	2,128,103
Balance, December 31, 2003		3,200	11,812,345	—	11,815,545
Net margin		—	3,186,603	—	3,186,603
Balance, December 31, 2004	$	3,200	14,998,948	—	15,002,148

See accompanying notes to consolidated financial statements.

KEPCo

Statements of Cash Flows

December 31, 2004 and 2003

		2004	2003
Cash flows from operating activities:			
Net margin	$	3,186,603	2,128,103
Adjustments to reconcile net margin to net cash provided by operating activities:			
Depreciation and amortization		3,817,830	3,977,830
Decommissioning		443,300	376,150
Amortization of nuclear fuel		1,795,148	1,559,637
Amortization of deferred charges		4,052,034	4,057,683
Amortization of deferred incremental outage costs		2,221,663	1,640,259
Amortization of debt issuance costs		668,799	454,861
Changes in assets and liabilities:			
Member accounts receivable		(111,404)	(450,097)
Materials and supplies		(126,980)	(101,506)
Other assets and prepaid expenses		(76,018)	(43,078)
Accounts payable		1,027,412	1,114,148
Payroll and payroll-related liabilities		20,594	(1,732)
Accrued property taxes		20,129	202,596
Accrued interest payable		(1,256,675)	1,231,844
Restricted assets		(71,032)	(91,623)
Other long-term liabilities		205,374	306,634
Net cash provided by operating activities		15,816,777	16,361,709
Cash flows from investing activities:			
Additions to electric plant, net		(2,130,735)	(1,631,880)
Additions to nuclear fuel		(2,660,067)	(2,533,135)
Additions to deferred incremental outage costs		(259,634)	(3,352,629)
Investments in decommissioning fund assets		(443,300)	(376,150)
Net cash used in investing activities		(5,493,736)	(7,893,794)
Cash flows from financing activities:			
Repayment of long-term debt		(13,320,150)	(8,220,390)
Issuance of debt		—	2,270,262
Increase in debt issuance costs		—	(2,327,018)
Net cash used in financing activities		(13,320,150)	(8,277,146)
Net increase (decrease) in cash and cash equivalents		(2,997,109)	190,769
Cash and cash equivalents at:			
Beginning of year		8,226,833	8,036,064
End of year	$	5,229,724	8,226,833
Supplemental disclosures of cash flow information:			
Cash paid during the year for interest	$	10,543,271	9,717,324

See accompanying notes to consolidated financial statements.

(1) Nature of Operations

Kansas Electric Power Cooperative, Inc. and subsidiaries (KEPCo), headquartered in Topeka, Kansas, was incorporated in 1975 as a not-for-profit generation and transmission cooperative (G&T). KEPCo is under the jurisdiction of the Kansas Corporation Commission (KCC) and was granted a limited certificate of convenience and authority in 1980 to act as a G&T public utility. It is KEPCo's responsibility to procure an adequate and reliable power supply for its 19 distribution rural electric cooperative members pursuant to all requirements of its power supply contracts. KEPCo is governed by a board of trustees representing each of its 19 members, which collectively serve more than 100,000 electric customers in rural Kansas.

(2) Summary of Significant Accounting Policies

(a) System of Accounts
KEPCo maintains its accounting records substantially in accordance with the Rural Utilities Service (RUS) Uniform System of Accounts and in accordance with accounting practices prescribed by the KCC.

(b) Rates
The KCC has the authority to establish KEPCo's electric rates under state law in Kansas. Rates are established to meet the times-interest-earned ratio and debt-service coverage set forth by the RUS. On January 17, 2002, the KCC ordered a rate increase of approximately $6.5 million, including an energy cost adjustment (ECA) mechanism, which allows KEPCo to pass along increases in certain energy costs to its cooperative members. These rates became effective February 1, 2002.

(c) Principles of Consolidation
KEPCo's consolidated financial statements include all majority-owned subsidiaries for which it maintains controlling interests. Undivided interests in jointly owned generation facilities are consolidated on a pro rata basis. All material intercompany accounts and transactions have been eliminated in consolidation.

(d) Utility Plant and Depreciation
Utility plant is stated at cost. The cost of repairs and minor replacements are charged to operating expenses as appropriate. Costs of renewals and betterments are capitalized. The original cost of utility plant retired and the cost of removal, less salvage, are charged to accumulated depreciation.

The composite depreciation rate for electric generation plant for the years ended December 31, 2004 and 2003 was 2.81% and 2.74%, respectively.

The provision for depreciation computed on a straight-line basis for electric and other components of utility plant is as follows:

Transportation and equipment	25 to 33%
Office furniture and fixtures	10 to 20%
Leasehold improvements	20%
Transmission equipment	10%

Depreciation expense was $3.8 million for each of the years ended December 31, 2004 and 2003, respectively.

(e) Nuclear Fuel
The cost of nuclear fuel in process of refinement, conversion, enrichment, and fabrication is recorded as utility plant asset at original cost and is amortized to nuclear fuel expenses based upon the quantity of heat produced for the generation of electric power. The permanent disposal of spent fuel is the responsibility of the Department of Energy (DOE). KEPCo pays one cent per net MWh of nuclear generation to the DOE for the future disposal service. These disposal costs are charged to nuclear fuel expense.

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(f) ***Investments***

Investments in debt securities are classified as available-for-sale in accordance with Statement of Financial Accounting Standards (SFAS) No. 115, *Accounting for Certain Investments in Debt and Equity Securities*, based on KEPCo's intended use of such securities. In the consolidated balance sheets, investments in debt securities with an original maturity greater than three months and a remaining maturity less than one year are presented as current assets, and investments with a remaining maturity greater than one year are presented as long-term investments. Investment returns realized in excess of contractual limits for unexpended loan proceeds are recorded as arbitrage rebate long-term liability in the consolidated balance sheets.

(g) ***Decommissioning Fund Assets/Decommissioning Liability***

As of December 31, 2004 and 2003, $7.2 million and $6.1 million, respectively, have been collected and are being retained in an interest-bearing trust fund to be used for the physical decommissioning of Wolf Creek. The trustee invests the decommissioning funds primarily in mutual funds, which are carried at estimated fair value. During 2003, the KCC extended the estimated useful life of Wolf Creek to 60 years from the original estimates of 40 years only for the determination of decommissioning costs to be recognized for ratemaking purposes. In 2003, the KCC approved a 2002 Wolf Creek decommissioning cost study, which decreased the estimate of total decommissioning costs to $468.4 million in 2002 dollars ($28.1 million is KEPCo's share). The study assumes a 4% rate of inflation and 2% rate of return. KEPCo adopted SFAS No. 143, *Accounting for Asset Retirement Obligations*, on January 1, 2003. SFAS No. 143 provides accounting requirements for the recognition and measurement of liabilities associated with the retirement of tangible long-lived assets. Under the standard, these liabilities will be recognized at fair value as incurred and capitalized and depreciated over the appropriate period as part of the cost of the related tangible long-lived assets.

SFAS No. 143 required KEPCo to recognize and estimate the liability for its 6% share of the estimated cost to decommission Wolf Creek, based on the present value of the asset retirement obligation KEPCo incurred at the time it was placed into service in 1985. On January 1, 2003, KEPCo recognized an asset retirement obligation of $11.7 million. In addition, utility plant in-service, net of accumulated depreciation, was increased by $2.9 million. These amounts were estimated based on the calculation guidelines of SFAS No. 143. KEPCo also established a regulatory asset for $3.9 million, which represents the amount of the Wolf Creek asset retirement obligation and accumulated depreciation not yet funded. A reconciliation of the asset retirement obligation for the years ended December 31, 2004 and 2003 is as follows:

	2004	2003
Balance at January 1	$ 12,385,380	11,684
Accretion	743,124	701
Balance at December 31	$ 13,128,504	12,385

The adoption of SFAS No. 143 did not impact net margin. Any net margin effects are deferred in the Wolf Creek decommissioning regulatory asset created pursuant to SFAS No. 71, *Accounting for the Effects of Certain types of Regulation.*

(h) ***Long-lived Assets***

Management reviews long-lived assets for impairment whenever events or changes in circumstances indicate the carrying amount of an asset may not be recoverable. In the event a long-lived asset was determined to be impaired, such asset would be required to be written down to its fair value, with the loss recognized in the consolidated statements of revenues and expenses.

(i) ***Cash and Cash Equivalents***

All highly liquid investments purchased with an original maturity of three months or less are considered to be cash equivalents and are stated at cost, which approximates fair value.

(j) ***Materials and Supplies Inventory***

Materials and supplies inventory are valued at average cost.

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(k) ***Unamortized Debt Issue Costs***
Unamortized debt issue costs relate to the issuance of the floating/fixed rate pollution control revenue bonds, mortgage notes payable to the National Rural Utilities Cooperative Finance Corporation (CFC) trusts and fees for repricing the Federal Financing Bank (FFB) debt. These costs are being amortized using the effective interest method over the remaining life of the bonds and notes.

(l) ***Cash Surrender Value of Life Insurance Contracts***
The following amounts related to Wolf Creek Nuclear Operating Corporation (WCNOC) Corporate-owned life insurance contracts, primarily with one highly rated major insurance company, are included in other investments on the consolidated balance sheets.

		2004	2003
Cash surrender value of contracts	$	4,206,023	3,910
Borrowings against contracts		(4,206,022)	(3,885
Net	$	1	25

Borrowings against contracts include a prepaid interest charge. KEPCo pays interest on these borrowings at a rate of 5.84% and 6.53% for the years ended December 31, 2004 and 2003, respectively.

(m) ***Revenues***
Revenues from the sale of electricity are recorded based on usage by member cooperatives and customers and on contracts and scheduled power usages, as appropriate.

(n) ***Income Taxes***
As a tax-exempt cooperative, KEPCo is exempt from income taxes under Section 501(c)(12) of the Internal Revenue Code of 1986, as amended. Accordingly, provisions for income taxes have not been reflected in the accompanying consolidated financial statements.

(o) ***Estimates***
The preparation of consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

(p) ***Reclassifications***
Certain prior year amounts in the consolidated financial statements have been reclassified where necessary to conform to the 2004 presentation.

(3) Factors that Could Affect Future Operating Results

KEPCo currently applies accounting standards that recognize the economic effects of rate regulation pursuant to SFAS No. 71, *Accounting for the Effect of Certain Types of Regulation*, and accordingly, has recorded regulatory assets and liabilities related to its generation and transmission operations. In the event KEPCo determines that it no longer meets the criteria of SFAS No. 71, the accounting impact could be a noncash charge to operations of an amount that would be material. Criteria that could give rise to the discontinuance of SFAS No. 71 include: (1) increasing competition that restricts KEPCo's ability to establish prices to recover specific costs, and (2) a significant change in the manner rates are set by regulators from a cost-based regulation to another form of regulation. KEPCo periodically reviews these criteria to ensure the continuing application of SFAS No. 71 is appropriate. Any changes that would require KEPCo to discontinue the application of SFAS No. 71 due to increased competition, regulatory changes, or other events may significantly impact the valuation of KEPCo's investment in utility plant, its investment in Wolf Creek, and necessitate the write-off of regulatory assets. At this time, the effect of competition and the amount of regulatory assets, which could be recovered in such an environment, cannot be predicted.

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The 1992 Energy Policy Act began the process of restructuring the United States electric utility industry by permitting the Federal Energy Regulatory Commission to order electric utilities to allow third parties to sell electric power to wholesale customers over their transmission systems. Many states are currently moving toward opening the retail segment to competition. The Kansas Legislature has not taken any significant action on industry restructuring that would have a direct impact on KEPCo. Management will continue to monitor deregulation initiatives, but does not presently expect any actions, which would be unfavorable to KEPCo, to be adopted within the next 12 months.

(4) Departures from Generally Accepted Accounting Principles

Effective February 1, 1987, the KCC issued an order to KEPCo requiring the use of present worth (sinking fund) depreciation and amortization. As more fully described in note 8, such depreciation and amortization methods constituted phase-in plans that did not meet the requirements of SFAS No. 92, *Accounting for Phase-In Plans.*

Effective February 1, 2002, the KCC issued an order that extended the depreciable life of Wolf Creek from 40 years to 60 years. This order also permitted recovery in rates of the $53.5 million cumulative difference between historical present worth (sinking fund) depreciation and amortization and straight-line depreciation and amortization of Wolf Creek generation plant and disallowed costs over a 15-year period. As more fully described in note 8, such depreciation and amortization methods constitute phase-in plans that do not meet the requirements of SFAS No. 92. Recovery of these costs in rates is included in operating revenues and the related amortization expense is included in deferred charges in the consolidated statements of revenue and expenses.

The effect of these departures from generally accepted accounting principles is to overstate (understate) the following items in the consolidated financial statements by the following amounts:

		2004	2003
Deferred charges	$	42,763,609	46,327
Patronage capital		42,763,609	46,327
Net margin		(3,563,634)	(3,563

(5) Wolf Creek Nuclear Generating Station

KEPCo owns 6% of Wolf Creek, which is located near Burlington, Kansas. The remainder is owned by the Kansas City Power & Light Company (KCPL—47%) and Kansas Gas & Electric Company (KGE—47%). KGE is a wholly owned subsidiary of Westar Energy, Inc. KCPL is a wholly owned subsidiary of Great Plains Energy Inc. KEPCo's undivided interest in Wolf Creek is consolidated on a pro rata basis. Substantially all of KEPCo's utility plant consists of its pro rata share of Wolf Creek. KEPCo is entitled to a proportionate share of the capacity and energy from Wolf Creek, which is used to supply a portion of KEPCo's members' requirements. KEPCo is billed on a daily basis for 6% of the operations, maintenance, administrative and general costs, and cost of plant additions related to Wolf Creek.

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 for up to five years under current regulations.

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

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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, including WCNOC, as well as the Compact Commission itself, 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 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 Compact Commission settled the case. The settlement requires Nebraska to pay the Compact Commission a one-time amount of $140.5 million or, alternatively, four annual installments of $38.5 million beginning in August 2005. The parties agreed to dismiss all pending litigation and appeals relating to this matter. Once Nebraska makes its final payment, it will be relieved of its responsibility to host a disposal facility. Meanwhile, the Compact Commission is pursuing other strategies for providing disposal capability for waste generators in the Compact region.

(6) Investments in Associated Organizations

Investments in associated organizations are carried at cost. At December 31, 2004 and 2003, investments in associated organizations, including CFC, consisted of the following:

		2004	2003
CFC:			
Membership	$	1,000	1,000
Capital term certificates		395,970	395,970
Subordianated term certificates		2,205,000	2,205,000
Patronage capital certificates		11,441	6,482
Equity term certificates		709,641	709,641
Other		84,040	59,129
	$	3,407,092	3,377,222

(7) Bond Fund Reserve

KEPCo has entered into a bond covenant whereby KEPCo is required to maintain, with a trustee, a bond fund reserve of approximately $4.2 million. This stipulated amount is sufficient to satisfy certain future interest and principal obligations. The amount held in the bond fund reserve is invested by the trustee in tax-exempt municipal securities, pursuant to the restrictions of the indenture agreement, which are carried at amortized cost.

(8) Deferred Charges

(a) Disallowed Costs

Effective October 1, 1985, the KCC issued a rate order relating to KEPCo's investment in Wolf Creek, which disallowed $26.0 million of KEPCo's investment in Wolf Creek ($16.4 net of accumulated amortization as of December 31, 2004). A subsequent rate order, effective February 1, 1987, allows KEPCo to recover these disallowed costs and other costs related to the disallowed portion (recorded as deferred charges) for the period from September 3, 1985, through January 31, 1987, over a 27.736-year period starting February 1, 1987. Pursuant to a KCC rate order dated December 30, 1998, the disallowed portion's recovery period was extended to a 30-year period. Through December 31, 2001, KEPCo used the present worth (sinking fund) method to recover the disallowed costs, which enables it to meet the times-interest-earned ratio and debt service requirements in the KCC rate order dated January 30, 1987. The method used by KEPCo through 2001 constituted a phase-in plan that did not meet the requirements of SFAS No. 92.

Effective February 1, 2002, the KCC issued an order permitting recovery in rates of the $6.5 million cumulative difference between historical present worth (sinking fund) and straight-line amortization of Wolf Creek disallowed costs over a 15-year period. Such depreciation practice does not constitute a phase-in plan that meets the requirements of SFAS No. 92.

If the disallowed costs were recovered using a method in accordance with accounting principles generally accepted in the United States, the costs would have been expensed in their entirety upon implementation of the KCC order, with a corresponding decrease in patronage capital.

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(b) ***Wolf Creek Deferred Plant Costs***

Effective February 1, 2002, the KCC issued an order permitting recovery in rates of the $46.9 million cumulative difference between historical present worth (sinking fund) depreciation and straight-line depreciation of Wolf Creek generation plant over a 15-year period. Such depreciation practice does not constitute a phase-in plan that meets the requirements of SFAS No. 92. In 2002, this cumulative difference was reclassified from utility plant allowance for depreciation to deferred charges on the consolidated balance sheets to reflect the amount as a regulatory asset. Amortization of the Wolf Creek deferred plant costs is included in amortization of deferred charges on the consolidated statements of revenue and expenses and amounted to $3.1 million for each of the years ended December 31, 2004 and 2003, respectively.

If the deferred plant costs were recovered using a method in accordance with accounting principles generally accepted in the United States, the costs would have been expensed in their entirety upon implementation of the KCC order, with a corresponding decrease in patronage capital.

(c) ***Decommissioning and Decontamination Assessments***

The Energy Policy Act of 1992 established a fund to pay for the decommissioning and decontamination of nuclear enrichment facilities operated by the DOE. A portion of this fund, not to exceed $2.25 billion, is to be collected from utilities that have purchased enrichment services from the DOE. This portion is limited to no more than $150.0 million each year and will be in the form of annual assessments that will not be imposed for more than 15 years. KEPCo has recorded its portion of this liability, which is being paid over 15 years. KEPCo has recorded a related deferred asset, which is being amortized to nuclear fuel expense over the 15-year assessment period.

(d) ***Deferred Incremental Outage Costs***

In 1991, the KCC issued an order that allowed KEPCo to defer its 6% share of the incremental operating, maintenance, and replacement power costs associated with the periodic refueling of Wolf Creek. Such costs are deferred during each refueling outage and are being amortized over the approximate 18-month operating cycle coincident with the recognition of the related revenues.

(e) ***Other Deferred Charges***

KEPCo includes in other deferred charges the early call premium resulting from refinancing the 1988 CFC Grantor Trust Certificates prior to maturity. This early call premium is amortized using the effective interest method over the remaining life of the new Grantor Trust Series 1997 certificates.

(9) Short-term Borrowings

As of December 31, 2004, KEPCo had a $15.0 million line of credit outstanding with the CFC. This line of credit has a term of 12 months. There were no outstanding borrowings at either December 31, 2004, or December 31, 2003.

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(10) Long-term Debt

Long-term debt consists of mortgage notes payable to the United States of America acting through the FFB, the CFC, and others. Substantially, all of KEPCo's assets are pledged as collateral. The terms of the notes as of December 31 are as follows:

		2004	2003
Mortgage notes payable to the FFB at fixed rates varying from 3.616% to 9.206%, payable in quarterly installments through 2018*	$	86,909,257	96,295
Mortgage notes payable to the Grantor Trust Series 1997 at a rate of 7.522%, payable semiannually, principal payments commenced in 1999 and continuing annually through 2017		47,740,000	49,640
Floating/fixed rate pollution control revenue bonds, City of Burlington, Kansas, Pooled Series 1985C, variable interest rate (ranging from 1.87% to 1.88% at December 31, 2004) payable annually through 2015		30,100,000	31,700
Mortgage note payable and equity certificate loan to the National Rural Utilities Cooperative Finance Corporation at fixed rates of 3.05% and 5.6%, payable quarterly through 2007 and 2017		4,832,764	5,267
		169,582,021	182,902
Less current portion		9,953,205	9,112
	$	159,628,816	173,790

*Mortgage notes payable to the FFB is presented net of $4,225,112 and $1,501,644 of cash deposited with the FFB for the future repayment of debt as of December 31, 2004 and 2003, respectively. These deposits are restricted for the future repayment of FFB debt and earn interest at a rate of 5 percent.

Aggregate maturities of long-term debt for the next five years and thereafter are as follows:

Year:		
2005	$	9,953,205
2006		10,638,964
2007		11,252,021
2008		11,946,939
2009		12,763,417
Thereafter		113,027,475
	$	169,582,021

Restrictive covenants require KEPCo to design rates that would enable it to maintain a times-interest-earned ratio of at least one-to-one and debt-service coverage of at least one-to-one, on average, in at least two out of every three years. The covenants also prohibit distributions of net patronage capital or margins until, after giving effect to any such distribution, total patronage capital equals or exceeds 20% of total assets unless such distribution is approved by RUS. KEPCo was in compliance with all restrictive covenants as of December 31, 2004 and 2003, respectively.

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In 1997, KEPCo refinanced its mortgage notes payable to the 1988 CFC Grantor Trust through the establishment of a new CFC Grantor Trust Series 1997 (the Series 1997 Trust) by CFC. This refinancing reduced the guaranteed interest rate payable on the mortgage notes to a fixed rate of 7.522% through the use of an interest rate swap that was assigned by KEPCo to the Series 1997 Trust. The mortgage notes payable are prepayable at any time with no prepayment penalties. However, any termination costs relating to the termination of the assigned interest rate swaps is KEPCo's responsibility. At December 31, 2004, the termination obligation associated with the assigned swap agreement to early retire the mortgage notes payable is approximately $15.9 million. This fair value estimate is based on information available at December 31, 2004 and is expected to fluctuate in the future based on changes in interest rates and outstanding principal balance.

KEPCo is also exposed to possible credit loss in the event of noncompliance by the counterparty to the swap agreement. However, KEPCo does not anticipate nonperformance by the counterparty.

(11) Benefit Plans

(a) National Rural Electric Cooperative Association (NRECA) Retirement and Security Program

KEPCo participates in the NRECA Retirement and Security Program for its employees. All employees are eligible to participate in this program after one year of service. In the master multi-employer plan, which is available to all members of NRECA, the accumulated benefits and plan assets are not determined or allocated by individual employees. KEPCo's pension expense under this program was $0.2 million for each of the years ended December 31, 2004 and 2003, respectively.

(b) NRECA Savings 401(k) Plan

All employees of KEPCo are eligible to participate in the NRECA Savings 401(k) Plan. Under the plan, KEPCo contributes an amount not to exceed 5%, dependent upon each employee's level of participation and completion of one year of service, of the respective employee's base pay to provide additional retirement benefits. KEPCo contributed $0.1 million to the plan for each of the years ended December 31, 2004 and 2003, respectively.

(c) Wolf Creek Nuclear Operating Corporation (WCNOC) Retirement Plans

KEPCo has an obligation to the WCNOC retirement and supplemental retirement plans for its 6% ownership interest in Wolf Creek. The plans provide for benefits upon retirement, normally at age 65. In accordance with the Employee Retirement Income Security Act of 1974, KEPCo has satisfied its minimum funding requirements. Benefits under the plans reflect the employee's compensation, years of service, and age at retirement.

Wolf Creek uses a measurement date of December 1 for its retirement plan and January 1 for its supplemental retirement plan.

The following sets forth KEPCo's share of the plans' changes in benefit obligation, plan assets, and funded status as of December 31:

		2004	2003
Changes in benefit obligation:			
Benefit obligation at beginning of year	$	6,373,620	5,683
Service cost		328,320	324
Interest cost		420,660	373
Actuarial loss		539,100	84
Benefits paid		(108,360)	(93
Benefit obligation at end of year	$	7,553,340	6,373
Accumulated benefit obligation	$	5,930,460	4,728

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Plan assets are invested in insurance contracts, corporate bonds, equity securities, United States government securities, and short-term investments.

		2004	2003
Changes in plan assets:			
Fair value of plan assets at beginning of year	$	3,421,140	2,843
Actual return on plan assets		325,680	334
Contributions during the year		486,360	313
Benefits paid		(85,380)	(71
Fair value of plan assets at end of year	$	4,147,800	3,421
Funded status	$	(3,405,540)	(2,952
Unrecognized net actuarial loss		1,945,380	1,479
Unrecognized prior service cost		28,080	32
Unrecognized net transition obligation		50,820	58
Postmeasurement date adjustments		94,500	56
Accrued benefit cost	$	(1,286,760)	(1,326
Actuarial assumptions used to determine benefit obligations:			
Discount rate		6.00%	6.
Annual salary increase rate		3.00%	3.

The asset allocation for the plans at the end of 2004 and 2003, and the target allocation for 2005, by asset category are as follows:

		Plan assets	
	Target allocation for 2005	2004	2003
Asset category:			
Equity securities	50% – 70%	65%	66%
Debt securities	30% – 50%	28%	33%
Other	0%	7%	1%
		100%	100%

WCNOC's pension plan investment strategy supports the objective of the fund, which is to earn the highest possible return on plan assets consistent with a reasonable and prudent level of risk. Investments are diversified across classes, sectors, and manager style to minimize the risk of large losses. WCNOC delegates investment management to specialists in each asset class and, where appropriate, provides the investment manager with specific guidelines, which include allowable and/or prohibited investment types. Investment risk is measured and monitored on an ongoing basis through quarterly investment portfolio reviews.

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KEPCo's share of the net periodic pension costs were as follows for the years ended December 31:

		2004	2003
Service cost	$	328,320	324
Interest cost on projected benefit obligation		420,660	373
Expected return on plan assets		(354,900)	(314,
Amortization of actuarial loss		102,360	76
Other		11,280	11
Total net periodic pension cost	$	507,720	472
Actuarial assumptions used to determine net periodic pension cost:			
Discount rate		6.20%	6.
Expected return on plan assets		9.00%	9.
Annual salary increase rate		3.20%	3.

The expected 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 the target asset allocations for each asset class, the overall expected rate of return for the portfolio was developed, adjusted for historical and expected experience of active portfolio management results compared to benchmark returns and for the effect of expenses paid from plan assets. In selecting the discount rate, fixed income security yield rates for corporate high-grade bond yields were considered.

KEPCo estimates cash contributions of $0.6 million will be made to the plans in 2005.

Estimated future benefit payments for the plans, which reflect expected future service, are as follows:

2005	$	126,000
2006		144,000
2007		168,000
2008		198,000
2009		234,000
2010 through 2014		1,884,000

(d) ***Wolf Creek Nuclear Operating Corporation (WCNOC) Postretirement Benefits***

KEPCo has an obligation to the WCNOC postretirement plan for its 6% ownership interest in Wolf Creek. This plan provides certain medical benefits to participants upon retirement. KEPCo's 6% obligation is presented in Wolf Creek nuclear operating liabilities in the accompanying consolidated balance sheets and was $0.4 million as of December 31, 2004 and 2003, respectively.

(12) Commitments and Contingencies

(a) ***Litigation***

There is a provision in the Wolf Creek operating agreement whereby the owners treat certain claims and losses arising out of the operation of Wolf Creek as a cost to be borne by the owners separately (but not jointly) in proportion to their ownership shares. Each of the owners has agreed to indemnify the others in such cases.

As is the case with other electric utilities, KEPCo, from time-to-time, is subject to various actions, which occasionally include punitive damage claims. KEPCo maintains insurance providing liability coverage; however, the insurance companies generally reserve the right to challenge insurance coverage for punitive damage recoveries. As of December 31, 2004, it is the opinion of the general counsel of KEPCo that there is not a significant probability that, as a result of pending or threatened personal injury actions, KEPCo will be liable for payment of actual or punitive damages in an amount material to the financial position of KEPCo.

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(b) ***Nuclear Liability and Insurance***

Pursuant to the Price-Anderson Act, KEPCo is required to insure against public liability claims resulting from nuclear incidents to the full limit of public liability, approximately $10.8 billion currently. 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 plan, owners are jointly and severally subject to a retrospective assessment of up to $100.6 million ($6.0 million—KEPCo's share) in the event there is a major nuclear incident involving any of the nation's commercial reactors. There is a limitation of $10.0 million ($0.6 million—KEPCo's share) in retrospective assessments per incident per year. This assessment is subject to an inflation adjustment based on the consumer price index and applicable premium taxes. If the $10.8 billion liability limitation is insufficient, the United States Congress will consider taking whatever action is necessary to compensate the public for valid claims.

The Price-Anderson Act (the Act) expired in August 2002, but was extended until December 31, 2003 for licensees. Licensees such as Wolf Creek continue to be grandfathered under the Act. The current version of a comprehensive energy bill expected to be adopted in 2005 by Congress contains provisions that would amend federal law addressing public liability from nuclear energy hazards in ways that would increase the annual limit on retrospective assessments from $10.0 million to $15.0 million per reactor per incident.

The owners carry decontamination liability, premature decommissioning liability, and property damage insurance for Wolf Creek totaling approximately $2.8 billion ($168.0 million—KEPCo's share). This insurance is provided by Nuclear Electric Insurance Limited (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. KEPCo's share of any remaining proceeds can be used to pay for property damage or decontamination expenses or, if certain requirements are met including decommissioning the plant, toward a shortfall in the decommissioning trust fund.

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 properly damage at Wolf Creek. If significant losses were incurred at any of the nuclear plants insured under the NEIL policies, KEPCo may be subject to retrospective assessments under the current policies of approximately $1.6 million.

Although KEPCo maintains various insurance policies to provide coverage for potential losses and liabilities resulting from an accident or an extended outage, KEPCo's insurance coverage may not be adequate to cover the costs that could result from a catastrophic accident of 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 KEPCo's financial condition and result of operations.

(c) ***Decommissioning Insurances***

KEPCo carries premature decommissioning insurance, which has several restrictions, one of which can only be used if Wolf Creek incurs an accident exceeding $500.0 million in expenses to safely stabilize the reactor, to decontaminate the reactor and reactor station site in accordance with a plan approved by the NRC, and to pay for on-site property damages. Once the NRC Property Rule, requiring insurance proceeds to first be used for stabilization and decontamination, has been complied with, the premature decommissioning coverage could pay for the decommissioning fund shortfall in the event an accident at Wolf Creek exceeds $500.0 million in covered damages and causes Wolf Creek to be prematurely decommissioned.

(d) ***Nuclear Fuel Commitments***

At December 31, 2004, KEPCo's share of WCNOC's nuclear fuel commitments were approximately $1.7 million for uranium concentrates expiring in 2007, $0.2 million for conversion expiring in 2007, $1.1 million for enrichment expiring at various times through 2006, and $6.7 million for fabrication through 2024.

(e) ***Purchase Power Commitments***

KEPCo has supply contracts with various utility companies to purchase power to supplement generation in the given service areas. KEPCo has recently executed a new five-year contract with Westar Energy through May 2008 with minimum purchase commitments of 85 megawatts per year.

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(13) Fair Value of Financial Instruments

The following methods and assumptions were used to estimate the fair value of each class of 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—The carrying amount approximates the fair value because of the short-term maturity of these investments.

Decommissioning Trust, Investments in Associated Organizations, and Bond Fund Reserve—The fair value of these assets is primarily based on quoted market prices as of December 31, 2004.

Variable-Rate Debt—The carrying amount approximates the fair value because of the short-term variable rates of those debt instruments.

Fixed-Rate Debt—The fair value of the fixed-rate FFB debt and the fixed-rate Series 1997 Trust debt is based on the sum of the estimated value of each issue, taking into consideration the current rates offered to KEPCo for debt of similar remaining maturities.

The estimated fair values of KEPCo's financial instruments are as follows:

		December 31, 2004	
		Carrying value	Fair value
Cash and cash equivalents	$	5,229,724	5,229,
Investments in associated organizations (including investments in CFC)		3,407,092	3,407,
Bond fund reserve		4,230,261	4,557,
Decommissioning trust		7,165,662	7,165,
Fixed-rate debt		139,482,021	143,571,
Variable-rate debt		30,100,000	30,100,

(14) Patronage Capital

In accordance with KEPCo's by-laws, KEPCo's current margins are to be allocated to members. KEPCo's current policy is to allocate margins to the members based on revenues collected from the members as a percentage of total revenues. If KEPCo's consolidated financial statements were adjusted to reflect accounting principles generally accepted in the United States of America, total patronage capital would be negative. As noted in the consolidated statements of changes in patronage capital, no patronage capital distributions were made to members in 2004 and 2003.

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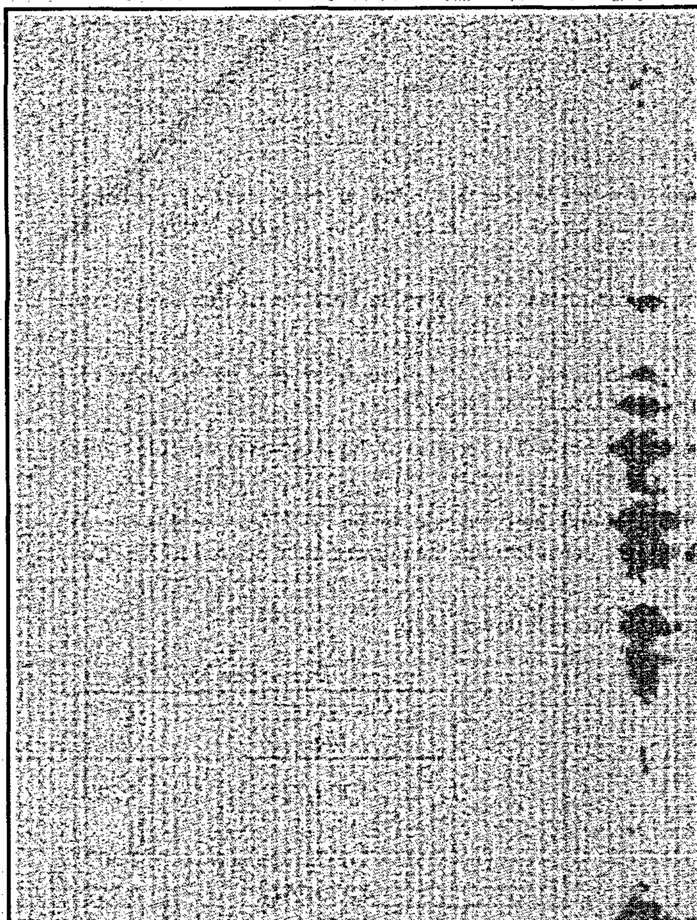

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