WOLF CREEK
NUCLEAR OPERATING CORPORATION

Kevin J. Moles
Manager Regulatory Affairs

May 14, 2007

RA 07-0047

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

Subject: Docket No. 50-482: Transmittal of 2006 Annual Financial Reports

Gentlemen:

Wolf Creek Nuclear Operating Corporation is transmitting one copy each of the 2006 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.

Sincerely,

Kevin J. Moles

KJM/rlt

Enclosures (3)

cc: J. N. Donohew (NRC), w/e
V. G. Gaddy (NRC), w/e
B. S. Mallett (NRC), w/e
Senior Resident Inspector (NRC), w/e

M004

Westar Energy®

2006 ANNUAL REPORT

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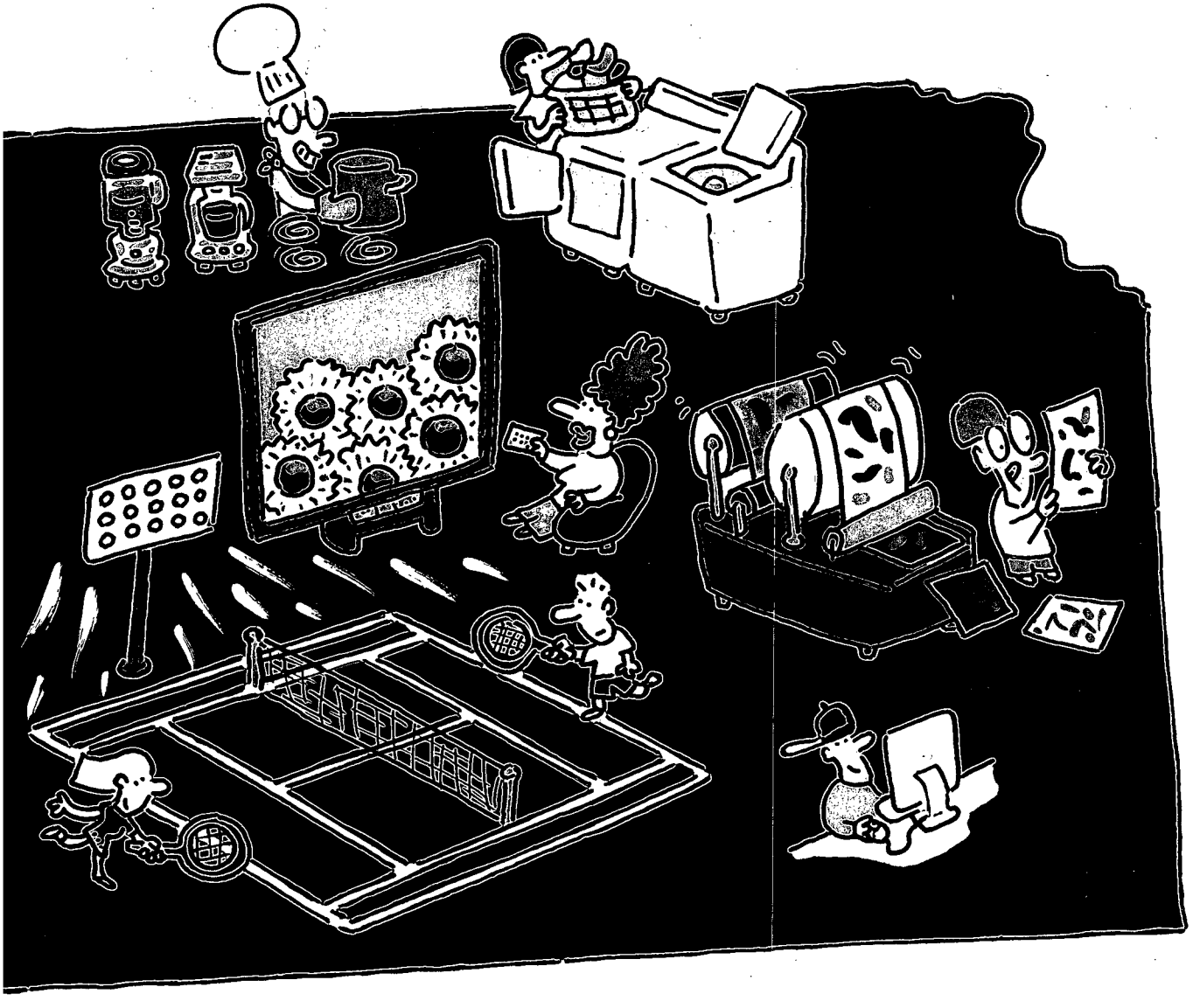


Cover illustration by Charlie Podrebarac, of Westwood, Kansas. Charlie has provided illustrations for the Westar Energy annual report the past four years. He has artfully captured the company's return to operating as a pure electric utility.

Dear Fellow Shareholder:

As reflected in our share price and in our financial statements, included in this report, we achieved very good financial results in 2006. Our total shareholder return from dividends and an increasing stock price was over 26%. And, as well, we took important steps to make new investments to provide for the future electricity needs of our Kansas customers.

In February 2007, we increased our indicated annual dividend per share to $1.08 from $1.00. At that time, our Board reiterated our dividend policy of paying out 60% to 75% of earnings, with a bias for being in the middle of that range and the upper half being possible only in extraordinary and non-recurring situations such as, for example, depressed earnings due to severely abnormal weather. Also in February, Standard & Poor's raised the ratings it assigns to our debt. That came on the heels of Moody's and Fitch also upgrading our credit ratings in 2006. All Westar debt rated by the three agencies now receives investment grade ratings, except corporate unsecured debt, which is rated BB+ by S&P.

We had an outstanding year in power generation. Our power plants operated at record levels to meet our customers' record peak demand of 4,822 MW on July 17. The new peak was 156 MW or 3.3% higher than the previous peak set in August 2003. That record was short-lived, however, as customer demand reached a new record 4,914 MW just two days later. These new peaks represent substantial growth in our customers' need for electricity. At forecasted rates of growth and to maintain contractually required generating reserve margins, we need to add in increments a total of about 900 MW of peaking capacity and about 600 MW of base load capacity by the middle of the next decade.

Our power generation employees met this new record output while also performing their jobs with the best annual safety performance in the history of our company. Our all-time low OSHA Recordable Accident Rate at our power plants of 0.77 meant that we had less than one injury for each 100 employees during the year. Based on OSHA statistics, our power plant employees are rated among the top 10% in safety. Our Jeffrey Energy Center achieved the distinction of being one of few industrial facilities to be nominated by OSHA for Star status in its Voluntary Protection Program, which is the highest level of OSHA safety recognition.

Our customer operations employees logged a 27% reduction in OSHA recordable injuries during 2006. Injuries requiring days away from work or resulting in job restrictions were at a historically low level placing our customer operations employees in the top quartile for comparable Edison Electric Institute transmission and distribution companies.

On October 31 we completed the acquisition of the 300 MW Spring Creek natural gas fueled plant in Oklahoma for $53 million. Attractively priced, we estimate that a new plant of similar size and type would have cost over $75 million more.

In late August we announced the construction of Emporia Energy Center, a 600 MW natural gas fueled peaking station with the first phase of 300 MW expected to begin service in the summer of 2008. The remaining 300 MW we expect to begin service in 2009. When completed we expect the total cost to be about $318 million.

We are also investing in substantial modifications to our existing coal fueled plants to comply with new environmental regulations under the Clean Air Act. We expect to invest about $745 million over the next seven to ten years on such equipment.

Wolf Creek, our 47% owned nuclear plant, established a new continuous run record of 506 days before it was taken off line in October to be refueled. The record long production run was followed by a record short 34-day refueling and maintenance outage.

On September 7, we announced plans to build a new 345 kilovolt high capacity transmission line from the Wichita area, northwest to Hutchinson and from there north to Salina. Following the announcement, we hosted open house meetings to gain insight from land owners along the potential routes for these lines. The information we gained from these meetings, along with other engineering and economic information, formed the basis of our formal application to the KCC in January 2007 for authority to construct the lines. These lines will substantially strengthen our transmission capability and will improve the reliability and economics of electric service in our service area and beyond.

Active summer and winter storm seasons for many of our neighboring utilities caused them to reach out to us for assistance to help them repair storm damaged equipment so that electric service to their customers could be restored. On two occasions last year we sent line crews to eastern Missouri. We also sent help to Oklahoma and western Kansas. Earlier this year, our neighbors in Nebraska requested our help. We were fortunate last year that our service area was largely free of damage from severe storms, but we know the day will come again when we need the same kind of assistance from others.

Part of meeting our customers' growing demand for electricity is to help them use it more wisely. In mid 2006 we launched an energy efficiency and conservation task force to identify several energy efficiency programs that we will initiate in 2007 and beyond.

We were pleased to again co-host the 23rd annual International Lineman's Rodeo. We are even more pleased to report that Westar is the home of the World Champion Journeyman Lineman team. Our team of three journeymen surpassed 200 teams from the U.S. and four other countries.

This year, as in recent years, we have included an essay with this Annual Report. This year's essay considers some of the implications for Westar of the current energy policy debate that is driven by climate change and long-term energy independence and security. We urge you to read it and if you have comments or questions about it to write or email us.

Thank you for your continued confidence.

Charles Q. Chandler IV
Chairman of the Board

James S. Haines, Jr.
President & CEO

Lessons Learned

By James Haines[1]

I. Purpose

The electric utility industry is now in the center of an energy policy debate that asks hard questions:

- Will we have enough electricity?
- What can we do to stop or limit climate change?
- How can we reduce dependence on foreign oil?

This debate comes as the industry has embarked on unprecedented investment in new power plants to satisfy continued growth in demand for electricity, modifying existing power plants to further improve air quality, and new transmission lines to expand and strengthen wholesale power markets.[2]

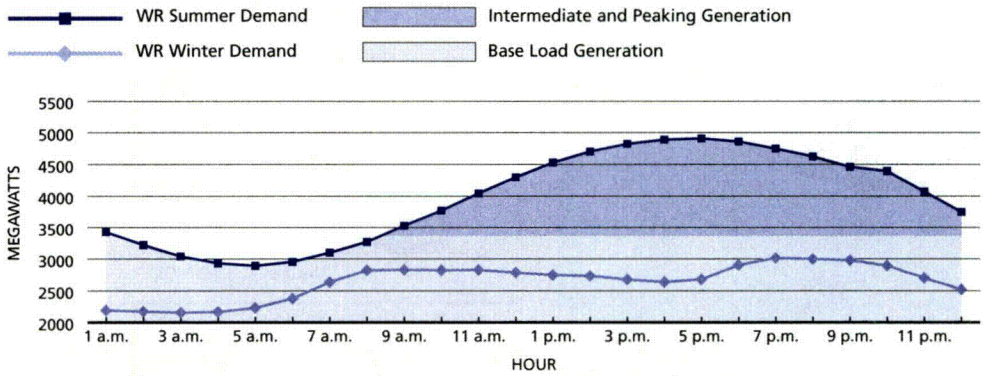
The last 30 years hold many examples of the difficulties inherent in establishing long-term electricity policy. Not least is that the investment cycle in a power plant can extend beyond 50 years while the life cycle of policies that affect power plants can be 10 years or less. Electric utilities' investors and customers pay dearly when policy is inconsistent with the practical exigencies of keeping the lights on. This essay will frame the nature of current energy policy debate and show its implications for Westar.

II. The Nature and Obligations of a Basic, Regulated Electric Utility

The Regulatory Compact

Electric utilities like Westar are granted state "certification" to be the exclusive provider of electricity in a specific area, and are legally obligated to provide safe, adequate, and reliable service at a regulated price to all within that area who will pay that price. In return, assuming regulators determine that its business has been prudently operated, the utility is given an opportunity to earn a profit comparable to that earned by other businesses having similar risks. This is often called the regulatory bargain or compact.

FIGURE 1 — Westar Typical Daily Load Profile



[1] Gina Penzig provided substantial research assistance. Mark Ruelle and James Ludwig provided significant comment. Robert Rives provided valued editorial assistance.

[2] Planned capital costs to comply with the Clean Air Interstate Rule and the Clean Air Mercury Rule are estimated at $47.8 billion from 2007 to 2025, without considering the cost of other federal, state and local mandates or possible carbon dioxide reduction mandates. Utilities invested $24 billion for emissions reduction equipment from 2002 to 2005. To meet the expected rise in demand for electricity, investments in power plants exceeding $275 billion will be required in the next 25 years. From 2006 to 2009, investment of $31.5 billion in transmission infrastructure is planned, a 60% increase over the previous five years. Investment in distribution systems is expected to average $14 billion per year over the next 10 years. Construction cost trends suggest these estimates are likely low; demand for resources has been driving project costs upward.

The Obligation to Plan for the Future

Fundamental to that compact is the utility's obligation to provide facilities necessary to meet customers' current and future electricity needs. Such facilities include primarily local distribution lines and equipment, high capacity transmission lines, and power plants. Here the focus will be on power plants. They require the most capital, consume the most resources, and present the widest array of choices.

Ideally, a utility's "mix" of power plants closely matches the pattern of its customers' demand for electricity — that is, how customer demand changes from one hour, day, or season to the next. **Figure 1** shows typical summer and winter daily demand curves for Westar's customers. The portion of demand that is constant for months at a time is served most efficiently with base load plants. These operate continuously. The portion of the load that occurs for only a few hours a day is served with peak load plants[3] that are engineered to be repeatedly started and stopped on short notice. Base plants are typically fueled with coal or uranium. They cost more to build than peak plants and take much longer to permit and construct, but their operating costs are usually lower. Peak plants are typically fueled with natural gas or oil.

Forecasting Risk

Because it can take as long as ten years to design, obtain necessary permits, and construct a base power plant — often costing more than $1 billion — utilities are substantially exposed to forecast risk. If regulators find that as a result of imprudent forecasting practices a utility has built too much power plant capacity or the wrong type, they can disallow recovery of all costs caused by the imprudent behavior.[4]

The Importance of an Interconnected High Capacity Transmission System

High capacity transmission lines move electricity from power plants to local distribution substations and lines. They serve other important functions as well. A well-interconnected transmission system is a key requirement for a vibrant wholesale electricity market, sharing power plant capacity reserves for use in emergencies,[5] and facilitating joint ownership in the construction of power plants.

FIGURE 2 — 2006 Generation by Fuel Type

All Units at Share. Excludes Spring Creek.

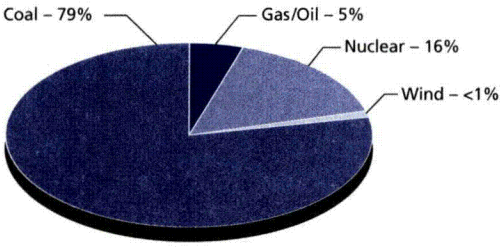
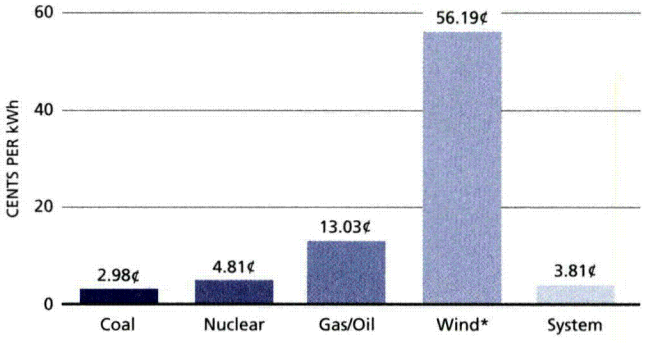


FIGURE 3 — 2006 Busbar Costs

All Units at Share. Excludes Spring Creek.



*Not representative of typical market costs. Market costs are about 5¢ to 8¢ per kWh before adjustments for tax incentives.

[3] Strictly speaking, there are three types of power plants: base, intermediate, and peak. For simplicity, since they have similar characteristics, intermediate plants are included here with peak plants.

[4] Because of their long lead-time, base power plants are particularly vulnerable to after the fact prudence reviews, if for no other reason than that policy and regulatory conditions can change dramatically in just a few years. Some states, including Kansas, permit or even require advance regulatory approval of power plants and thus offer some protection against second-guessing based on hindsight.

[5] Reserve capacity can be needed when equipment breaks down, growth in demand is greater than forecasted, the supply of power plant fuel is interrupted, transmission lines fail or are congested, or weather is extreme.

Consider just a few examples. At one point, utility "A" might be able to generate additional electricity at an incremental cost of, say, 2 cents per kilowatt hour when it costs utility "B" 3 cents. Through interconnected lines, A can sell to B at a negotiated price between 2 and 3 cents so both are better off. Or, consider that A and B each need a new 300 MW power plant. Each could build its own or, with interconnections jointly build one 600 MW plant and reduce costs by taking advantage of economies of scale. Or, utility "C" might own no power plants and thus must buy all the power needed by its customers. Through an interconnected system, both A and B might desire to sell to C, thus permitting C to purchase at a competitive price.

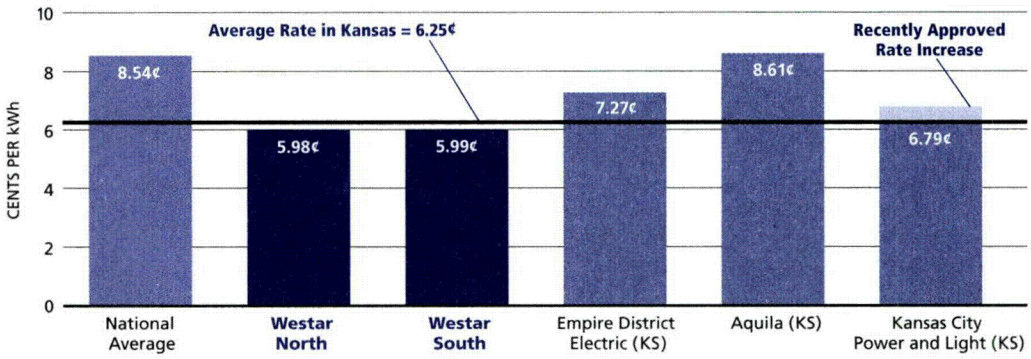
Those are basic examples. In reality, thousands of such transactions occur every hour of every day and can involve much greater complexity and many, many companies across broad areas. When the interconnected transmission system is not adequate to handle the transactions, inefficiencies result that can cost millions of dollars per year even for a small utility like Westar.

Westar's Power Plants, Their Reliability and Costs

Figure 2 shows Westar's sources of electricity by fuel type in 2006. **Figure 3** shows their average cost for capital, operations and maintenance, and fuel. **Figures 2** and **3** show that about 95% of the electricity Westar produces comes from its low cost, base plants fueled with coal or uranium. Importantly, in 2006 on average each of Westar's base plants was available 89% of the time[6] and some combination of them produced power 100% of the time. The economic benefits of Westar's generation mix are perhaps best shown in **Figure 4**. Westar's retail rates are about 30% below the national average and the lowest of any investor owned utility in Kansas.[7]

A seldom appreciated quality of a *system* of power plants is reliability. Anything short of 100% availability of electric power is failure. Few industries work to such a standard; few other commodities are as crucial to our way of life. Indeed, indirectly if not directly, shelter, water, and food depend upon electricity being continuously available.[8] Because there is no practical way to store electricity on a large scale, it must be generated virtually at the moment it is consumed, at the very moment of demand.[9]

FIGURE 4 — Attractive Retail Rate Comparison



Source: EEI July 1, 2006

[6] After accounting for the need to conserve coal in early 2006, this is top quartile performance.

[7] Apropos of a utility's obligation to plan for the future, Westar's low rates are due to coal and uranium fueled power plants built in the 1970's and early 1980's. Ironically, when Westar's nuclear plant, Wolf Creek, started operations in 1985 the Kansas Corporation Commission initially denied a return on 78% of KG&E's investment in Wolf Creek. While much of that return was eventually granted, it wasn't until after more than $100 million had been written off as a loss.

[8] Thus a utility must proceed with caution when considering unproven technology whose reliability can suffer for years as costly "kinks" are worked out.

[9] For that reason, wind generated power cannot eliminate the need for conventional power plants, it can only displace them when the wind is blowing just right which, in Kansas under ideal conditions, occurs randomly about 40% of the time.

Plans to Satisfy the Increasing Demand for Electricity by Westar Customers

From 1997 to 2006, the peak demand by Westar's customers grew from 3,808 MW to 4,805 MW, an annual compound growth rate of 2.6%. **Figure 5** shows the forecasted annual peak demand from 2007 to 2016 plus a contractually required reserve margin of at least 12%. Assuming that Westar adds no new capacity, **Figure 5** also shows Westar becoming capacity deficient in 2008. To address this, Westar plans to add capacity as shown by the light blue bars in **Figure 5**. The additions in 2008, 2009, 2011 and 2012 are natural gas fueled peak plants. The addition in 2014 is assumed to be a base plant. The anticipated cost of these additions is about $2 billion.

Figure 6 shows Westar's existing high capacity transmission lines and new lines it plans within the next five years. The estimated cost is about $180 million to $220 million.

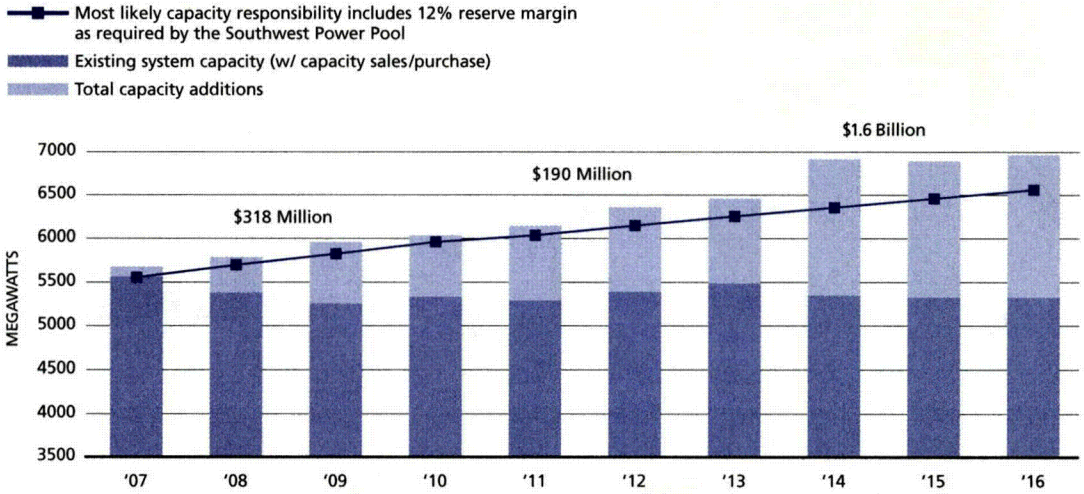
III. Electricity Policy Changes over the Last 30 Years

The Sky Is Falling

Electricity policy in the 1970's was shocked by four events. First, after a decade of apparent declines in natural gas supplies,[10] Congress passed the Power Plant and Industrial Fuel Use Act of 1978, immediately banning new gas fueled power plants and prohibiting its use in existing plants after 1989. Second, the Mideast oil embargoes of 1973 and 1978 ended the era of cheap oil and led to prolonged weakness in the economy. Third, orders for nuclear power plants halted after the 1979 accident at the Three Mile Island reactor. Fourth, annual growth in electricity demand fell from 7% plus, that had persisted for decades, to less than 3%.[11]

Despite the uncertainty this created, electric utilities remained legally obligated to meet current and future demand for electricity. In the late 1960's and early 1970's, they planned and started building coal and uranium fueled power plants not only to replace existing gas fueled plants but also to satisfy projected annual growth in demand of 7%. By the end of the 1970's, everything had turned upside down, with severe consequences for customers and shareholders alike.

FIGURE 5 — System Capacity



[10] In fact, gas was scarce because regulated prices for gas at the wellhead were held so low that gas exploration and production had become unprofitable.

[11] For long-term planning purposes, such a drop creates a dilemma. Is a one or two year decline an anomaly or a new trend?

From 1970 to 1985 the average retail price per kWh of electricity increased from 1.86 to 6.47 cents. Market prices of utility stocks fell from well above book value to slightly less than 75% of book value in 1981. Many companies dropped from A or better credit quality to BBB or lower. Regulators disallowed from rate recovery over $11 billion in capital invested in new power plants.[12]

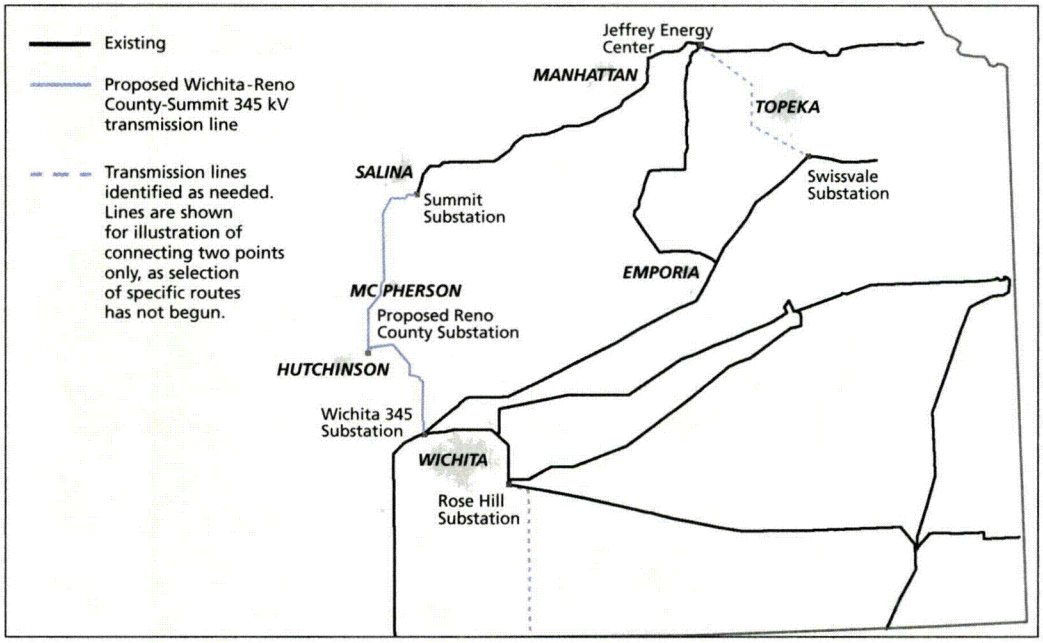
By the mid 1980's, natural gas had done an about face. Its predicted disappearance became a glut once its wellhead price was deregulated and producers could charge a price that compensated for the costs and risks of exploring for and producing it. The Power Plant and Industrial Fuel Use Act was repealed. Clearly, energy policy from the 1970's and early 1980's caused some painfully expensive failures. Ironically, one significant success, re-establishing plentiful and relatively inexpensive gas supplies, ultimately led to colossal failure.

The Grass Is Greener

The return of cheap and plentiful natural gas in the 1990's brought the illusion that electric utilities had been wrongheaded in converting to coal and uranium fueled power plants in the 1970's and early 1980's. The cost of electricity from new state of the art natural gas fueled plants was, for the time being, significantly lower. Entrepreneurs eagerly built them. Companies like Enron were ready to create new, competitive electricity markets, but only if policy makers would free them from bureaucratic price regulation.

Academic theorists and large industrial consumers seeking lower rates led policy makers to view regulation as at best a sub-optimal way to set electricity prices. An unregulated, competitive *retail* market surely would be better. The market would deal swiftly with imprudent, inefficient managers. The best managers would be amply rewarded, and customers would see quick, big benefits from better prices and service. California and 16 other states set out for the Promised Land.

FIGURE 6 — 345 kV Transmission Lines



[12] In the longrun, those plants have proven themselves as reliable and low cost producers of power.

The Grass Is Not

There is no need to dwell on the results. One California utility was driven into bankruptcy, another nearly so. Customers were left holding a hugely expensive mess. In no state that moved to retail competition for electricity has the promise of lower rates come true.[13] In most, rates have risen sharply. In many cases, perhaps in every case, the legislatively mandated path to retail competition was flawed. Certainly, in theory retail competition should work. But in practice to date, it has failed.[14] This failure cannot be attributed to acts of God, unforeseeable events, or uncontrollable acts of foreign sovereigns.

IV. Issues Now Driving Electric Energy Policy Debate

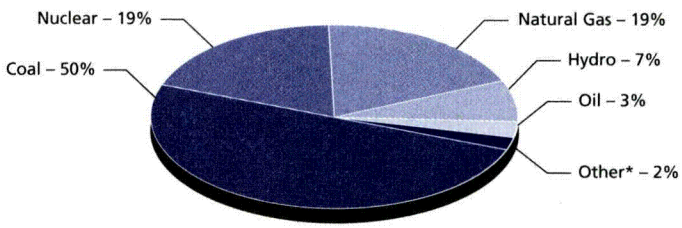
The Sky Is Really Falling?

Figure 7 shows the sources of electricity generated in the U.S. Many people believe the amount of electricity generated by coal makes that chart a gloomy picture. Forget that, at the present rate of use and with present technology, there is within the continental U.S. more than a 200-year supply of coal. Generating with coal, while far cleaner than it once was, is still dirty from the mine to the stack. Burning coal to make electricity releases substantially more legally defined pollutants into the atmosphere than burning natural gas or oil: NOx (nitrogen oxide), SO_2 (sulphur dioxide), Hg (mercury),[15] CO (carbon monoxide), and PM (particulate matter).

Figure 8 shows the major sources for each of those pollutants in 2001. Since 1985, the electric power industry has reduced the most significant emissions, NOx and SO_2, from power plants by 48% and 55%, respectively. By 2015 the reduction of these pollutants is predicted to reach 80% and 88%. *Importantly, from 1985 to 2015 the Energy Information Agency estimates that electricity production will increase by 90%.* Still, with present technology, such pollutants, at some level, remain a fact of life for coal-fueled plants.

Increasingly, however, concerns with burning fossil fuels, especially coal, have focused upon the release of CO_2 (carbon dioxide).[16] Many believe CO_2 accumulation in the atmosphere, along with other "greenhouse gasses,"[17] is a principal

FIGURE 7 — National Fuel Mix



Source: U.S Department of Energy, Energy Information Administration (EIA), 2005 preliminary data

*"Other" includes generation by agriculture waste, batteries, chemicals, geothermal, hydrogen, landfill gas recovery, municipal solid waste, purchased steam, solar, sulfur, wind and wood.

[13] Some have argued, albeit unpersuasively and with tortured analysis, that continued regulation would have produced even higher prices.

[14] In the same time period, a competitive wholesale market was developing. For a variety of reasons, wholesale competition has largely worked to the benefit of customers and shareholders.

[15] The EPA estimates that 87% of the mercury deposited in the United States is from international sources.

[16] Fossil fuel power plants account for about 41% of CO_2 releases in the U.S. Vehicles account for about 33% of such releases. The second most abundant greenhouse gas, methane, has 21 times more heat trapping capacity than CO_2. Methane is released from diverse sources such as rice paddies and animal digestive processes, sources far harder to regulate than power plants or vehicles.

[17] Naturally occurring and manmade greenhouse gases, for examples, include water vapor, carbon dioxide, methane, nitrous oxide, ozone, hydrofluorocarbons, and sulfur hexafluoride. Greenhouse gases insulate our planet and, thereby, make life as we know it possible. The concern is that a disproportionate accumulation of greenhouse gases, i.e. too much insulation, will lead to overheating the planet.

contributor to, if not the sole cause of, climate change.[18] Notably, the EPA has not yet determined CO_2 to be a pollutant and its emission is not subject to regulation.[19]

Many people believe the slice of the pie chart in **Figure 7** taken by nuclear is as grim a picture as the slice taken by coal. They cite the terrible consequences that could follow if highly radioactive material were to be released from a U.S. nuclear plant or from radioactive materials in transit. It is of no comfort, they say, that there is only the slightest chance of such a thing happening and an even slighter chance of an ensuing threat to public safety. And even if all the plants run flawlessly, we still, they say, have to safely store radioactive waste from such plants for thousands of years.

Energy Independence

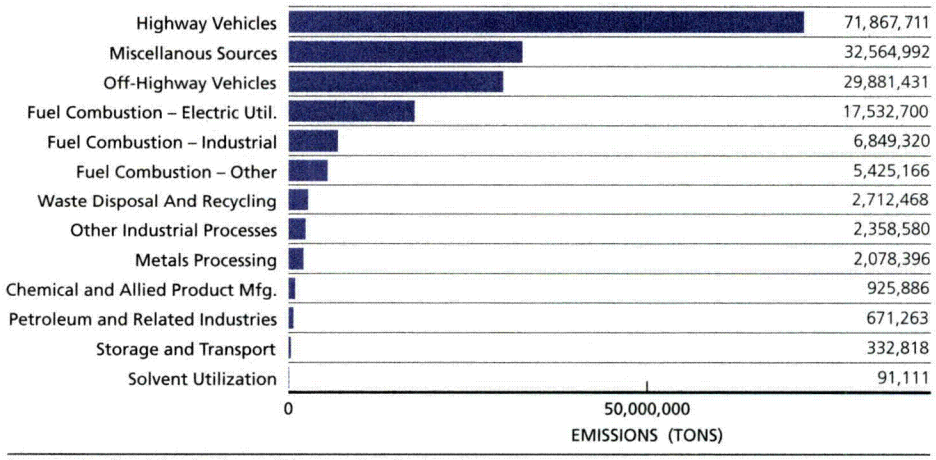
Debate about energy independence is focused almost exclusively on oil. In 2005, 60% of oil consumed in the U.S. was from foreign sources. The U.S. consumes 7.5 billion barrels of oil annually. Transportation consumes 68% while electricity production consumes just 3%. The National Resources Defense Council has estimated that oil consumption can be reduced 40% by 2025 through greater use of bio-fuels, electric vehicles, and increased efficiency.

Current Electricity Policy Debate

"Warming of the climate system is unequivocal, as is now evident from observations of increases in global average air and ocean temperatures, widespread melting of snow and ice, and rising global mean sea level. Most of the observed increase in globally averaged temperatures since the mid 20th century is very likely due to the observed increase in anthropogenic greenhouse gas concentrations. Discernible human influences now extend to other aspects of climate, including ocean warming, continental-average temperatures, temperature extremes and wind patterns," according to the Intergovernmental Panel on Climate Change report released February 2, 2007.[20]

FIGURE 8 — Pollutant Emissions

Total emission for 2001 for each category is a combination of the air pollutants CO, NOx, PM10, PM2.5 and SO_2 which are regulated under the Clean Air Act. Mercury is regulated under the Clean Air Mercury Rule. In 1999, the most recent year for which information is available, of the 144 tons of mercury deposited in the United States, 11.1 tons was from U.S. utilities. Under current laws that amount will be reduced to about 3.4 tons by 2018.



Source: US EPA Office of Air and Radiation, NEI Database. Edison Electric Institute.

[18] "Climate change is the single greatest environmental challenge facing the world today. Scientists overwhelmingly agree that the global community must reduce emissions of greenhouse gases, including CO_2, to well below 1990 level within a few decades, if we are to stabilize the climate at acceptable levels." December 15, 2006, letter from the Attorneys General of eight states to the Kansas Department of Health and Environment protesting the proposed construction of three 700 MW coal fueled power plants in western Kansas by Sunflower Electric Power Corporation. In contrast: "Even a complete ban on burning fossil fuels in the U.S. wouldn't halt progress to the next milestone, a doubling of atmospheric carbon dioxide since the advent of civilization. No joke to say the only live question for congresspersons and their voters back home is: How much are we going to spend to have no impact on global warming, and why?" Holman Jenkins, "Decoding Climate Politics," THE WALL STREET JOURNAL, 1/24/07, at A12.

[19] In Massachusetts v. EPA this question is pending before the U.S. Supreme Court.

[20] For an excellent summary of the problem and potential solutions see: "Energy's Future Beyond Carbon," Scientific American, September 2006 Special Issue.

Even before release of that report, political leaders in the U.S. were making almost daily calls for legislation and regulations to reduce CO_2 emissions, to sharply curtail construction of new coal plants, and to aggressively accelerate programs to conserve electricity and use it more efficiently. A few states and even cities have enacted laws that attempt to limit CO_2 emissions.

Congressional leaders have pledged to pass major legislation dealing with climate change and energy independence. In a January 18, 2007, news release, Speaker Pelosi stated: "For America to be safe and strong, we must take further decisive action now to free our country of its dependence on foreign energy sources and to confront the rising tide of global warming. … We hope to have legislation on global warming and energy independence through the committees by July 4th. …"

Policy Debate And Reality: Collision Or Convergence?

Electricity plays an ever more essential role in every aspect of contemporary life. As a practical matter, any electricity policy that would degrade electricity's reliability or supply will fail.

Many people assert that renewable sources of electricity, primarily wind and solar, coupled with conservation and efficiency, can eliminate the need for new coal or nuclear plants.[21] In 2005, 9%, about 1 of every 11 kWh, of electricity consumed in the U.S. came from renewable resources. Total electricity generated in the U.S. in 2005 was 4,025 billion kilowatt hours. It is estimated that by 2030 electricity consumption in the U.S. will grow 44% to 5,788 billion kWh. The EPA estimates that by 2025 conservation and efficiency can cut projected demand by 20%. As **Figure 9** shows, even the leading forms of renewable sources of electricity were a tiny portion of installed U.S. generation capacity at the beginning of 2006. Perhaps this is why reliable cost information is elusive. However, even wind, which is identified as one of the lower cost sources, is about 5 to 8 cents per kilowatt hour – well above the 2.98 cents per kWh for Westar's coal-fueled generation in 2006. **Figure 10** shows their annual capacity factor, that is, the amount they actually produce relative to what they would produce if they operated continuously at full capacity.

Figure 9, when compared with **Figure 7,** illustrates another important fact. Because conventional sources of electricity are generally more reliable than renewable sources, they account for a larger portion of actual energy production (fuel mix) than implied by their share of total capacity.

FIGURE 9 — Nameplate Capacity by Source

Source: Energy Information Administration

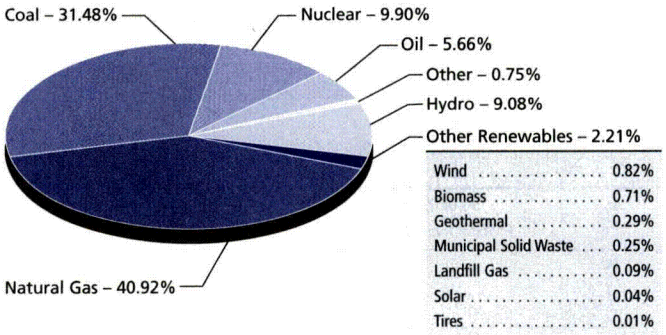
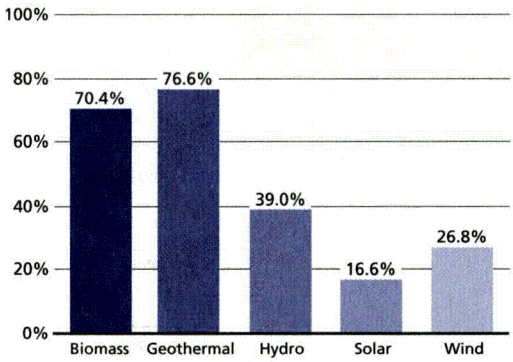


FIGURE 10 — Proven Renewables Capacity Factor

Source: Energy Information Administration



[21] Typically when we think of conservation and efficiency we have in mind the use of energy by end users, i.e. retail customers, whether residential, commercial or industrial. In fact, the greatest potential for efficiency gains is in the power plants themselves. It is estimated that a 2% increase in the efficiency of coal-fueled power plants would exceed all additional renewable power generation through 2030.

Now, while capacity factor is an industry-accepted measurement for reliability for most forms of generation, wind and solar energy present special challenges because regardless of how well maintained the plant is, it only produces electricity when the wind blows or the sun shines. For example, while a coal or gas fueled plant, even a plant fueled by biomass, can be predictably put in operation when need is highest, sufficient wind must blow to produce electricity with a wind turbine; a requirement beyond control of the operator.

Figure 11 shows the output of electricity from the two wind farms in Kansas that were operational on July 17, 2006, a day Westar Energy's customers set a record with their demand for electricity. In the early evening as the need for electricity rose, output from these wind farms dropped. Without other resources, residents would have come home in mid-summer heat without adequate energy to cool and light their homes or prepare evening meals.

At the end of 2006, 23 states and the District of Columbia had laws or regulations requiring a certain percentage of electricity to come from renewable sources by a certain date. For example, Texas law requires 2,000 MW of renewable energy by 2009. In 2006, Arizona and New Jersey increased their renewable requirement to 15% of electricity production by 2015 and 20% by 2020.

Uranium and coal are the most abundant sources of energy within U.S. boundaries. They accounted for 69% of electricity generated in the U.S. in 2005. As a practical matter, any electricity policy that does not include coal and uranium will fail.

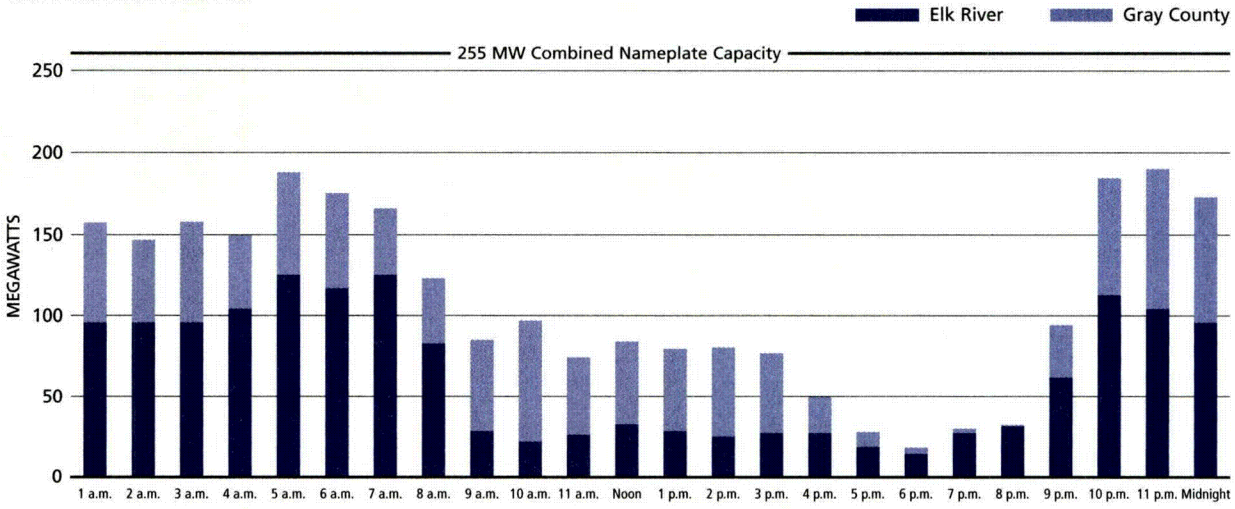
While in theory a coal plant can emit virtually no pollutants or CO_2, no such plants exist today.[22] New technology often goes through a trial and error period; this process of working out the "kinks" inevitably increases costs and degrades reliability.

If CO_2 is a major contributor to climate change, then any energy policy that does not directly address CO_2 emissions will fail.[23]

If the reduction or elimination of CO_2 emissions is mandated, there will be significant increases in the price of electricity and other forms of energy.

FIGURE 11 — Wind Farm Output July 19, 2006

Source: Southwest Power Pool



[22] The FutureGen Alliance aims to build the world's first fossil-fueled zero-emissions power plant. The 275 MW plant will produce both electricity and hydrogen. The project was launched in 2005 and is currently in the site selection stage. It is scheduled to begin operation in 2012.

[23] Capturing and storing meaningful quantities of CO_2 is a vastly different and separate technical challenge from designing and building a coal-fueled power plant that is "capture" ready.

Fossil fueled power plants are not the only sources of greenhouse gas emissions. Any energy policy, to be successful, must address all major sources, not just power plants. While all CO_2 emitters should be proportionately covered by a policy, it is important to recognize that carbon emissions from some sources can be reduced less expensively than from others. Accordingly, a policy should be flexible enough to permit reduction or offset so the greatest reductions are achieved at the lowest cost.

Nuclear power plants produce no air emissions. No new nuclear plants have been started in the U.S. since the late 1970's.[24] Through a tax on nuclear generated electricity, the Department of Energy has collected $28 billion for a radioactive waste facility that, by law, was to be operating by 1998. That facility, in Nevada, is nothing more than a glorified hole in the ground and is years, if not decades, from opening. Some say it will never open. Some say there will be no new nuclear plants until such a facility is open.

Conventional wisdom is that conservation and efficiency are a function of price: as electricity becomes relatively more expensive, more substitutes for electricity become economically viable.[25] Many new programs to encourage conservation and efficiency are being tried throughout the U.S. It remains to be seen if they can dramatically reduce, let alone eliminate, the need for new coal and uranium power plants.

Nonetheless, conservation and efficiency simply are not sources of electricity. They can make existing sources go further and, therefore, deserve an important place in electricity policy. But even if every viable conservation and efficiency practice is implemented to its maximum extent there will remain a need for electricity and eventually for new power plants.

It is not unreasonable to think that, if conservation and efficiency and renewable electricity sources are economic, entrepreneurs will bring them to market without a legal mandate. The need for a legal mandate suggests they are not economic in all cases. That in turn suggests that as such mandates are satisfied, electric rates will increase.

Energy conservation and efficiency can achieve short-term gains to buy the time necessary to develop clean coal technology and permanent radioactive waste disposal facilities.[26]

It is a little appreciated fact that as we have become more efficient in extracting energy sources (e.g. coal, oil, gas, uranium), more efficient in converting those sources to electricity, and more efficient in using electricity, *we have used more electricity, not less!*[27] For those counting on conservation and efficiency as part of a long-term solution, that should be sobering.

Final Thoughts

Electricity policy, ultimately, will succeed or fail based on the choices of those who use electricity. When a utility, such as Westar, announces it needs a new power plant, it reflects the myriad choices its customers have made and, importantly, is complying with its legal obligation to satisfy the electricity demands that result from those choices.

One customer choice that has been very nearly universal is *100% reliability at low rates.* Thus, when a utility builds a coal fueled plant instead of wind powered plants, it is not reflecting a preference for coal over wind, rather it is reflecting its

[24] While there is much talk about a resumption of nuclear plant construction and while significant amounts are being invested in new designs and while the Nuclear Regulatory Commission has made the licensing process more rational, there have been no ground breaking ceremonies.

[25] The irony here is that if regulators and policy makers have proven resistant to anything it is to increasing the price of electricity.

[26] Reprocessing (recycling) spent nuclear fuel to "harvest" its unused energy would reduce the volume of waste needing to be permanently stored and would significantly increase the supply of nuclear fuel to make electricity. Other countries, France and Japan for example, reprocess nuclear fuel. The U.S. stopped reprocessing nuclear fuel in the late 1970's. Opposition to reprocessing is generally based on the fact that one of its by-products, plutonium, while it can be used as reactor fuel, also can be used in weapons.

[27] See Huber and Mills, The Bottomless Well, Chap. 7, "The Paradox of Efficiency", pp. 108 – 123, Basic Books (2005). For example, "Efficiency may curtail demand in the short term, for the specific task at hand. But its long-term impact is just the opposite. When steam-powered plants, jet turbines, car engines, light bulbs, electric motors, air conditioners, and computers were much less efficient than today, they also (in the aggregate) consumed much less energy. The more efficient they grew, the more of them we built, and the more we used them – and the more energy they consumed overall. Per unit of energy used, the United States produces more than twice as much GDP today as it did in 1950 – and total energy consumption in the United States has risen three-fold." Id. at 111. Perhaps an example from another technology is more illustrative. According to Moore's Law, the power of computer processors doubles about every 18 months. As computer processing has followed Moore's Law and become more efficient, the demand for computers has increased exponentially. "Power consumption of server systems doubled between 2000 and 2005, requiring the generating capacity of about 14 power plants world-wide." The Wall Street Journal, 2/15/07, at B3. Also, to the extent that electricity plays a role in achieving energy independence, for example to fuel electric vehicles, the demand for electricity will increase.

customers' choices for a form of power generation that is reliable and low cost versus a form that is diametrically opposite. If and when wind powered plants alone or in combination with some other form of generation match the reliability and cost of coal fueled plants, they will no doubt be preferred.

Climate change is a global problem. Certainly, first world countries, like the U.S., should assume proportionate leadership responsibility in seeking and implementing appropriate solutions. A grand solution is unlikely. More likely the solution will come in many steps and places and be hugely complex and vulnerable to unintended consequences.

Data show conclusively that over long periods, measured in epochs, average global temperatures rise and fall, sometimes dramatically and rapidly. For the time life has been present on our planet, it has adapted to these climate changes. Adaptation should not be ruled out as at least part of the response to climate change.

Generating, transmitting, and distributing electricity, as well as extracting and transporting the fuels used in power plants, are fraught with potential hazards. But when the good that comes from electricity[28] is considered, it is decisively not a devil's bargain that we choose electricity, while working diligently to minimize the potential of those hazards.

What is the place of electric utilities in forming energy policy? Certainly, electric utilities, along with others, should be sources of information necessary to inform the debate. And certainly, electric utilities will participate as advocates in the debate. But this is not a debate and not a policy that should be dominated by one or any collection of interest groups. It should be dominated by sound science and objective engineering and economic information.[29]

Where sound science and objective information reveal a solution, policymakers must have the courage to impose it. For example, developing a radioactive waste facility or imposing conservation and efficiency standards should not be held hostage by parochial or "not in my back yard" interests.

It will not work for policy to be established one utility, one state or one region at a time. A patchwork approach will only result in a crazy quilt that might look good but will keep no one warm.

As recounted, recent electricity policy has not uniformly succeeded and at times has been a downright failure. This has not always been due to flawed policy. Often it has been due to many moving parts over which no individual or entity has control and about which there can be no clairvoyance.

Conclusion

On balance, utilities that have been most successful during periods of policy change and turmoil have been those that stayed closest to their basic mission of providing safe, reliable, high quality electric service at a reasonable cost. Ironically, the policy experiment with deregulation drove affected utilities away from that basic mission toward diversification. We at Westar have worked single mindedly over the last four years to return to basics. By any measure we have succeeded. We are well prepared to deal with anticipated changes in electricity policy and, at the same time, "keep the lights on" for the benefit of customers and shareholders alike.

[28] While it is not without issues, electricity is by far the cleanest and most productive form of energy ever put to use by man.

[29] California's debacle with deregulation has been attributed to a fundamentally flawed deregulation law that was a product of the appeasement of the various interest groups that participated in the legislative process. On the scales of social, economic, moral, and political difficulty, regulating California energy markets should have been child's play compared with the geo social, economic, moral, and political complexities of reversing climate change.

Financial Measures 2006:

	2006	2005
FINANCIAL DATA *(Dollars in Millions)*		
INCOME HIGHLIGHTS		
Sales	**$1,606**	$1,583
Income from continuing operations	**165**	135
Results of discontinued operations, net of tax	**—**	1
Earnings available for common stock	**164**	135
BALANCE SHEET HIGHLIGHTS		
Total assets	**$5,455**	$5,210
Common stock equity	**1,539**	1,416
Capital structure:		
Common equity	**49%**	45%
Preferred stock	**1%**	1%
Long-term debt	**50%**	54%
OPERATING DATA		
Sales (Thousands of MWh)		
Retail	**19,558**	19,217
Wholesale	**7,418**	8,440
Customers	**669,000**	660,000
COMMON STOCK DATA		
PER SHARE HIGHLIGHTS		
Earnings per share:		
Basic earnings available from continuing operations	**$1.88**	$1.54
Discontinued operations, net of tax	**—**	$0.01
Basic earnings available	**$1.88**	$1.55
Dividends declared per common share	**$1.00**	$0.92
Book value per share	**$17.61**	$16.31
STOCK PRICE PERFORMANCE		
Common stock price range:		
High	**$27.24**	$24.97
Low	**$20.09**	$21.07
Stock price at year end	**$25.96**	$21.50
Average equivalent common shares outstanding (in thousands)	**87,510**	86,855
Dividend yield (based on year end annualized dividend)	**3.9%**	4.3%

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, 2006

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

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer (as defined in Rule 12b-2 of the Act). Check one: Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐

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

The aggregate market value of the voting common equity held by non-affiliates of the registrant was approximately $1,834,449,044 at June 30, 2006.

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	87,494,258 shares
(Class)	(Outstanding at February 15, 2007)

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 2007 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 matters such as, but not limited to: amount, type and timing of capital expenditures; earnings; cash flow; 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; regulatory 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: regulated and competitive markets; economic and capital market conditions; changes in accounting requirements and other accounting matters; changing weather; the ultimate impact of the remand by the Kansas Court of Appeals to the Kansas Corporation Commission arising from appeals filed by interveners of portions of the December 28, 2005 rate Order; the impact of regional transmission organizations and independent system operators, including the development of new market mechanisms for energy markets in which we participate; rates, cost recoveries and other regulatory matters including the outcome of our request for reconsideration of the September 6, 2006 Federal Energy Regulatory Commission Order; the impact of changes and downturns in the energy industry and the market for trading wholesale energy; the outcome of the notice of violation received on January 22, 2004 from the Environmental Protection Agency and other environmental matters including possible future legislative or regulatory mandates related to carbon dioxide emissions and climate change; political, legislative, judicial and regulatory developments at the municipal, state and federal level that can affect us or our industry; 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; the impact of changes in interest rates on 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 changes in estimates regarding our Wolf Creek Generating Station decommissioning obligation; changes in regulation of nuclear generating facilities and nuclear materials and fuel, including possible shutdown or required modification of nuclear generating facilities; uncertainty regarding the establishment of interim or permanent sites for spent nuclear fuel storage and disposal; homeland security considerations; coal, natural gas, uranium, oil and wholesale electricity prices; availability and timely provision of equipment, supplies, labor and fuel we need to operate our business; 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 669,000 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. KGE owns a 47% interest in the Wolf Creek Generating Station (Wolf Creek), a nuclear power plant located near Burlington, 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.

SIGNIFICANT BUSINESS DEVELOPMENTS

New Generation and Transmission Construction Plans

We plan significant increases in investments in new generation, new transmission and air emission controls at existing fossil-fueled power plants. These investments include new projects and higher investment estimates for previously announced projects, which have increased due to rising prices of labor, materials and supplies.

In August 2006, we announced plans to build a new natural gas-fired combustion turbine peaking power plant near Emporia in Lyon County, Kansas. We expect the new plant, which we have named the Emporia Energy Center, to have an initial generating capacity of up to 300 megawatts (MW), with additional capacity to be added in a second phase, bringing the total capacity to approximately 600 MW. We expect the total investment in the plant to be about $318 million. We plan to begin construction on the new plant in the spring of 2007. The initial phase of the plant is scheduled to begin operation in the summer of 2008.

In September 2006, we announced plans to build a transmission line from our Gordon Evans Energy Center northwest of Wichita, Kansas, to a new substation near Hutchison, Kansas, then onto our Summit substation near Salina, Kansas, a distance totaling approximately 86 miles. In January 2007, we filed an application with the Kansas Corporation Commission (KCC) to request permission to build the line. Kansas law requires the KCC to issue an order within 120 days of our filing regarding our application. If the KCC issues a permit for us to proceed, we expect to complete construction in 2009. Our preliminary cost estimate for the project is $80 million to $100 million. This estimate could change materially as engineering and construction proceed. In addition to this line, we plan additional expansions to our electric transmission network in Kansas. These include a new line from our Rose Hill substation near Wichita to the Kansas-Oklahoma border, where we expect to interconnect with new facilities built by an Oklahoma-based utility, and a new line from our Jeffrey Energy Center to an existing substation about 15 miles south of Topeka, Kansas.

In May 2005, we initiated a study to identify potential sites suitable for a new coal-fired power plant. We said that we intended to ultimately select and announce the preferred site for a base load coal plant by the end of 2006. Due primarily to the significant increase in the estimated costs of constructing such a facility, in December 2006, we announced that we would delay making such a decision. We continue to evaluate how we will meet our future base load capacity needs.

During 2005 and 2006 we announced plans to make significant investments in our coal plants to reduce air emissions from these plants. The estimated costs of those investments have increased since those earlier announcements. For additional information, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Future Cash Requirements."

Changes in Rates

In accordance with a 2003 KCC Order, on May 2, 2005, we filed applications with the KCC for it to review our retail electric rates. On December 28, 2005, the KCC issued an order (2005 KCC Order) authorizing changes in our rates, which we began billing in the first quarter of 2006, and approved various other changes to our rate structures. In April 2006, interveners filed appeals with the Kansas Court of Appeals challenging various aspects of the 2005 KCC Order. On July 7, 2006, the Kansas Court of Appeals reversed and remanded for further consideration by the KCC three elements of the 2005 KCC Order. The balance of the 2005 KCC Order was upheld.

On February 8, 2007, the KCC issued an order in response to the Kansas Court of Appeals' decision regarding the 2005 KCC Order. In its February 8, 2007 Order the KCC: (i) confirmed its original decision regarding its treatment of the La Cygne unit 2 sale-leaseback transaction; (ii) in lieu of a transmission delivery charge, ruled that it intends to permit us to recover our transmission related costs in a manner similar to how we recover our other costs; and (iii) reversed itself with regard to the inclusion in depreciation rates of a component for terminal net salvage. The February 8, 2007 KCC Order requires us to refund to our customers the amount we have collected related to terminal net salvage. We have recorded a regulatory liability at December 31, 2006 in the amount of $16.4 million related to this item. For additional information, see Note 3 of the Notes to Consolidated Financial Statements, "Rate Matters and Regulation."

OPERATIONS

General

Westar Energy supplies electric energy at retail to approximately 360,000 customers in central and northeast Kansas and KGE supplies electric energy at retail to approximately 309,000 customers in south-central and southeastern Kansas. We also supply electric energy at wholesale to the electric distribution systems of 45 cities in Kansas and four electric cooperatives in Kansas. We have other 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 retail service territory.

In 2006, we implemented a retail energy cost adjustment (RECA) that allows us to recover the cost of fuel consumed in generating electricity and purchased power needed to serve our customers. Through the RECA, we bill our customers on a month ahead estimate. The RECA then provides for an annual review and reconciliation of estimated and actual fuel and purchased power costs. The annual review also affords the KCC a means to determine the prudence of our fuel and purchased power expenses. If the KCC determines any expenses are imprudent, it will likely disallow recovery of those costs.

Generation Capacity

We have 6,033 MW of accredited 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	3,286.0	54.5
Nuclear	548.0	9.1
Natural gas or oil	2,117.0	35.1
Diesel fuel	81.0	1.3
Wind	1.2	—
Total	6,033.2	100.0

Our aggregate 2006 peak system net load of 4,914 MW occurred on July 19, 2006. Our net generating capacity, combined with firm capacity purchases and sales, provided a capacity margin of 11% above system peak responsibility at the time of our 2006 peak system net load.

Under wholesale agreements, we provide generating capacity to other entities as set forth below.

Utility	Capacity (MW)	Period Ending
Midwest Energy, Inc.	25	May 2007
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
Oneok Energy Services Co.	75	December 2015
McPherson Board of Public Utilities (McPherson)	(a)	May 2027

[a] *We provide base load capacity to McPherson, and McPherson provides peaking capacity to us. During 2006, we provided approximately 78 MW to, and received approximately 179 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 less fuel it takes to produce electricity. We measure the quantity of heat consumed during the generation of electricity in millions of Btu (MMBtu).

Based on MMBtus, our 2006 fuel mix was 79% coal, 16% nuclear and 5% natural gas, oil and diesel fuel. We expect that our fuel mix in 2007 will have a higher percentage of uranium usage because we do not have a scheduled outage at Wolf Creek in 2007. Our fuel mix fluctuates with the operation of Wolf Creek, fluctuations in fuel costs, plant availability, customer demand and the cost and availability of power in the wholesale market.

Coal

Jeffrey Energy Center: The three coal-fired units at Jeffrey Energy Center have an aggregate capacity of 2,190 MW, of which we own an 84% share, or 1,839 MW. We have a long-term coal supply contract with Foundation Coal West to supply coal to Jeffrey Energy Center from surface mines located in the Powder River Basin (PRB) in Wyoming. The contract contains a schedule of minimum annual MMBtu delivery quantities. All of the coal used at Jeffrey Energy Center is purchased under this contract. The contract expires December 31, 2020. The contract provides for price escalation based on certain costs of production. The price for quantities purchased over the scheduled annual minimum is subject to renegotiation every five years to provide an adjusted price for the ensuing five years that reflects then current market prices. The next re-pricing for those quantities over the scheduled annual minimum will occur in 2008.

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

The average delivered cost of coal burned at Jeffrey Energy Center during 2006 was approximately $1.37 per MMBtu, or $23.29 per ton.

La Cygne Generating Station: The two coal-fired units at La Cygne Generating Station (La Cygne) have an aggregate generating capacity of 1,422 MW, of which we own or lease a 50% share, or 711 MW. La Cygne unit 1 uses a blended fuel mix containing approximately 85% PRB coal and 15% Kansas/Missouri coal. La Cygne unit 2 uses PRB coal. The operator of La Cygne, Kansas City Power & Light Company (KCPL), arranges coal purchases and transportation services for La Cygne. All of the La Cygne unit 1 and La Cygne unit 2 PRB coal is supplied through fixed price contracts through 2010 and is transported under KCPL's Omnibus Rail Transportation Agreement with the BNSF and Kansas City Southern Railroad through December 31, 2010. As the PRB coal contracts expire, we anticipate that KCPL will negotiate new supply contracts or purchase coal on the spot market. The La Cygne unit 1 Kansas/Missouri coal is purchased from time to time from local Kansas and Missouri producers.

During 2006, the average delivered cost of all coal burned at La Cygne unit 1 was approximately $1.10 per MMBtu, or $19.06 per ton. The average delivered cost of coal burned at La Cygne unit 2 was approximately $0.92 per MMBtu, or $15.58 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 774 MW. During 2005, we began purchasing coal under a contract with Arch Coal, Inc. This contract extends 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 2006 and 2007 and approximately 43% of the coal to be delivered under this contract is priced within a specified range of spot market prices for 2008 and 2009.

BNSF transports coal for these energy centers from Wyoming under a contract that expires in December 2008.

During 2006, the average delivered cost of all coal burned in the Lawrence units was approximately $1.15 per MMBtu, or $20.32 per ton. The average delivered cost of all coal burned in the Tecumseh units was approximately $1.15 per MMBtu, or $20.38 per ton.

Natural Gas

We use natural gas either as a primary fuel or as a start-up and/or secondary fuel, depending on market prices, at our Gordon Evans, Murray Gill, Neosho, Abilene and Hutchinson Energy Centers, in the gas turbine units at Tecumseh Energy Center and in the combined cycle units at the State Line facility and the Spring Creek Energy Center. We can also use natural gas as a supplemental fuel in the coal-fired units at the Lawrence and Tecumseh Energy Centers. During 2006, we purchased 14.7 million MMBtu of natural gas on the spot market for a total cost of $95.7 million. Natural gas accounted for approximately 5% of our total MMBtu of fuel burned during 2006 and approximately 24% of our total fuel expense. From time to time, we may purchase derivative contracts or use other fuel types in an effort to mitigate the effect of high natural gas prices. For additional information on our exposure to commodity price risks, see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

We maintain natural gas transportation arrangements for the Abilene and Hutchinson Energy Centers with Kansas Gas Service, a division of ONEOK, Inc. This contract expires April 30, 2007. We are currently renegotiating this contract. 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. We meet all of the natural gas transportation requirements for the Spring Creek Energy Center through an interruptible natural gas transportation agreement with ONEOK Gas Transportation, LLC.

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 2006 oil was moderately more expensive than natural gas, and because of the additional handling cost of oil and additional environmental considerations associated with oil, we did not use oil as the primary fuel in these generating facilities in 2006. During 2006, we burned only 0.3 million MMBtu of oil at a total cost of $2.3 million. Oil accounted for less than 1% of our total MMBtu of fuel burned during 2006 and approximately 1% of our total fuel expense. From time to time, we may purchase derivative contracts or use other fuel types in an effort to mitigate the effect of high oil prices. For additional information on our exposure to commodity price risks, see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

We also use oil to start some of our coal 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 contract. We maintain quantities in inventory that we believe will allow us to facilitate economic dispatch of power, to satisfy emergency requirements and to protect against reduced availability of natural gas for limited periods.

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

Other Fuel Matters

The table below provides our weighted average cost of fuel, including transportation costs.

	2006	2005	2004
Per MMBtu:			
Nuclear	$ 0.41	$ 0.42	$ 0.39
Coal	1.25	1.20	1.11
Natural gas	6.49	8.53	6.62
Oil	9.19	4.97	3.77
Per MWh Generation:			
Nuclear	$ 4.28	$ 4.34	$ 4.05
Coal	13.69	13.20	12.27
Natural gas/oil	66.91	68.19	52.98
All generating stations	14.94	15.36	12.64

Purchased Power

At times, we purchase electricity instead of generating it ourselves. Factors that cause us to make such purchases include planned and unscheduled outages at our generating plants, prices for wholesale energy, extreme weather conditions and other factors. Transmission constraints may limit our ability to bring purchased electricity into our control area, potentially requiring us to curtail or interrupt our customers as permitted by our tariffs and terms and conditions of service. Purchased power for the year ended December 31, 2006 comprised approximately 7% of our total operating expenses. The weighted average cost of purchased power was $54.90 per MWh in 2006, $59.05 per MWh in 2005 and $54.10 per MWh in 2004.

Energy Marketing Activities

We engage in both financial and physical trading with the goal of increasing profits, managing commodity price risk and enhancing system reliability. We trade electricity, coal, natural gas and oil. We use a variety of financial instruments, including forward contracts, options and swaps, and we trade energy commodity contracts.

Nuclear Generation

General

Wolf Creek is a 1,166 MW nuclear power plant located near Burlington, Kansas. KGE owns a 47% interest in Wolf Creek, or 548 MW, which represents 9% of our total generating capacity. KCPL owns an equal 47% interest, with Kansas Electric Power Cooperative, Inc. (KEPCo) holding the remaining 6% interest. The co-owners pay operating costs equal to their percentage ownership in Wolf Creek.

In September 2006, Wolf Creek Nuclear Operating Corporation (WCNOC), the operating company for Wolf Creek, filed a request with the Nuclear Regulatory Commission (NRC) for a 20 year extension of Wolf Creek's operating license. Currently, the operating license will expire in 2025. We anticipate that the NRC may take up to two years before it rules on the request. The NRC may impose conditions as part of any approval. Based on the experience of other nuclear plant operators, we believe that the NRC will ultimately approve the request.

Fuel Supply

We have under contract 100% of the uranium and conversion services needed to operate Wolf Creek through March 2011. During 2006, we entered into contracts with suppliers which will cover a majority of Wolf Creek's uranium and conversion needs through 2017. Fabrication and enrichment requirements are under contract through 2024.

Because of a supply interruption at a major Canadian uranium mine, Wolf Creek will defer a small portion of the uranium fuel scheduled for delivery in 2007. This supply interruption may impact Wolf Creek's uranium deliveries in subsequent years as well. In anticipation of this possibility, Wolf Creek's owners authorized the purchase of additional uranium from an alternate supplier. We expect this purchase, combined with Wolf Creek's on-going operations strategies including its previous acquisition of strategic inventory, will minimize the impact of this fuel supply interruption. We cannot provide assurance that our mitigation efforts will eliminate the risk that supplies are not delivered as needed.

We have entered into all uranium, uranium conversion and uranium enrichment arrangements, as well as the fabrication agreements in the ordinary course of business. We believe Wolf Creek is not substantially dependent on these agreements. However, contraction and consolidation among suppliers of these commodities and services, increasing worldwide demand, past inventory draw-downs and flooding of a key mine of a leading industry supplier have introduced uncertainty as to the ability to replace, if necessary, volumes under these contracts in the event of a protracted supply disruption. We believe this uncertainty is not unique in the nuclear industry.

Radioactive Waste Disposal

Under the Nuclear Waste Policy Act of 1982, the Department of Energy (DOE) is responsible for the permanent disposal of spent nuclear fuel. Wolf Creek pays into a federal Nuclear Waste Fund administered by the DOE a quarterly fee for the future disposal of spent nuclear fuel. Our share of the fee was $4.1 million in 2006, $3.8 million in 2005 and $4.3 million in 2004 and is calculated as one-tenth of a cent for each kilowatt-hour of net nuclear generation produced. We include these costs in operating expenses.

In 2002, the Yucca Mountain site in Nevada was approved by the DOE for the development of a nuclear waste repository for the disposal of spent nuclear fuel and high level nuclear waste from the nation's defense activities. This action allows the DOE to apply to the NRC to license the project. Currently, the DOE has not defined a schedule for submitting a license application. The opening of the Yucca Mountain site has been delayed many times and could be delayed further due to litigation and other issues related to the site as a permanent repository for spent nuclear fuel. Wolf Creek has on-site temporary storage for spent nuclear fuel expected to be generated by Wolf Creek through 2025, the term of its existing operating license.

Wolf Creek disposes of all classes of its low-level radioactive waste at existing third-party repositories. Should disposal capability become unavailable, we believe Wolf Creek is able to store its low-level radioactive waste in an on-site facility. We believe that a temporary loss of low-level radioactive waste disposal capability would not affect Wolf Creek's continued operation.

The Low-Level Radioactive Waste Policy Amendments Act of 1985 mandated that the various states, individually or through interstate compacts, develop alternative low-level radioactive waste disposal facilities. The states of Kansas, Nebraska, Arkansas, Louisiana and Oklahoma formed the Central Interstate Low-Level Radioactive Waste Compact (Central States Compact), and the Central States Compact Commission, which is responsible for creating new disposal capability for the member states. The Central States Compact Commission selected Nebraska as the host state for the disposal facility.

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

Outages

Wolf Creek operates on an 18-month refueling and maintenance outage schedule. Wolf Creek was shut down for 34 days in 2006 for its fifteenth scheduled refueling and maintenance outage. During outages at the plant, we met our electric demand primarily with our other generating units and by purchasing power. As provided by the KCC, we defer and amortize evenly the incremental maintenance costs incurred for planned refueling outages over the unit's 18 month operating cycle. Wolf Creek is next scheduled to be taken off-line in the spring of 2008 for its sixteenth refueling and maintenance outage.

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

The NRC evaluates, monitors and rates various inspection findings and performance indicators for Wolf Creek based on their safety significance. Wolf Creek currently meets all NRC oversight objectives and receives the minimum regimen of NRC inspections. Although not expected, the NRC could impose an unscheduled plant shutdown due to security or other concerns. Those concerns need not be related to Wolf Creek specifically, but could be due to concerns about nuclear power generally, or circumstances at other nuclear plants in which we have no ownership.

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 sufficient funds required for nuclear decommissioning will be accumulated prior to the expiration of the license of the related nuclear power plant. Wolf Creek files a nuclear decommissioning and dismantlement study with the KCC every three years.

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

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

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

We recovered in rates and deposited in an external trust fund approximately $3.9 million for nuclear decommissioning in 2006 and 2005 and $3.8 million in 2004. We record our investment in the nuclear decommissioning fund at fair value. The fair value approximated $111.1 million as of December 31, 2006 and $100.8 million as of December 31, 2005.

Competition and Deregulation

The Federal Energy Regulatory Commission (FERC) requires owners of regulated transmission assets to allow third party wholesale providers of electricity nondiscriminatory access to their transmission systems to transport electric power to wholesale customers. FERC also requires us to provide transmission services to others under terms comparable to those we allow 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 competitive wholesale power markets.

Regional Transmission Organization

We are a member of the SPP, the RTO in our region. On September 19, 2006 the KCC approved an order allowing us to transfer functional control of our transmission system to the SPP under its membership agreement and applicable tariff. The SPP coordinates the operation of our transmission system within an interconnected transmission system that covers all or portions of eight states. The SPP collects revenues for the use of each transmission owner's transmission system. Transmission customers transmit throughout the entire SPP system power purchased and generated for sale or bought for resale in the wholesale market. Transmission capacity is sold on a first come/first served non-discriminatory basis. All transmission customers are charged rates applicable to the transmission system in the zone where energy is delivered, including transmission customers 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, although we expect higher costs due to the administrative costs of the RTO and associated markets. At this time, we are unable to quantify these costs because market implementation issues remain unresolved. We expect that we will recover these costs in rates we charge to our customers.

Real-Time Energy Imbalance Market

The SPP is required by FERC to implement a real-time market to accommodate financial settlement of energy imbalances within the SPP region. An energy imbalance exists when a market participant's actual power inputs to or outputs from the transmission network differ from the level of inputs and outputs scheduled by the transmission user. The intent of a real-time market system is to permit more efficient balancing of energy production and consumption through the use of market protocols. The SPP implemented the real-time energy imbalance market on February 1, 2007. At this time we are unable to determine what impact this may have on our results of operations.

Regulation and Rates

Kansas law gives the KCC general regulatory authority over our rates, extensions and abandonments of service and facilities, the classification of accounts, the issuance of some securities and various other matters. We are also subject to the jurisdiction of FERC, which has authority over wholesale sales of electricity, the transmission of electric power and the issuance of some securities. We are subject to the jurisdiction of the NRC for nuclear plant operations and safety.

FERC Proceedings

Request for Change in Transmission Rates: On May 2, 2005, we filed applications with FERC that proposed a formula transmission rate providing for annual adjustments to our transmission costs. This is consistent with our proposals filed with the KCC on May 2, 2005 to charge retail customers separately for transmission service through a transmission delivery charge. The proposed FERC transmission rates became effective, subject to refund, December 1, 2005. On November 7, 2006 FERC issued an order reflecting a unanimous settlement reached by the parties to the proceeding. The settlement modified the rates we proposed and requires us to refund approximately $3.4 million, which includes the amount we collected in the interim rates since December 2005 and interest on that amount.

Environmental Matters

General

We are subject to various federal, state and local environmental laws and regulations. These laws and regulations relate primarily to discharges into the air, air quality, discharges of effluents into water, the use of water, and the handling and disposal of hazardous substances and wastes. These laws and regulations require a lengthy and complex process for obtaining licenses, permits and approvals from governmental agencies for our new, existing or modified facilities. If we fail to comply with such laws and regulations, we could be fined or otherwise sanctioned by regulators. We have incurred and will continue to incur capital and other expenditures to comply with environmental laws and regulations. The 2005 KCC Order established the environmental cost recovery rider (ECRR), which will allow for the timely inclusion in rates of capital investments we make related directly to environmental improvements required by the Clean Air Act.

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

Air Emissions

The Clean Air Act, state laws and implementing regulations impose, among other things, limitations on major pollutants, including sulfur dioxide (SO_2), particulate matter and nitrogen oxides (NOx).

Certain Kansas Department of Health and Environment (KDHE) regulations applicable to our generating facilities prohibit the emission of SO_2 in excess of prescribed 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 of this act. We have not had to make any material capital expenditures to meet Phase II SO_2 and NOx requirements.

Title IV of the Clean Air Act created an SO_2 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 SO_2 emissions allowances for each affected emitting unit. An SO_2 allowance is a limited authorization to emit one ton of SO_2 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 SO_2 in excess of their allowances may purchase allowances in the market in which such allowances are traded. In 2006, we had emissions allowances adequate to meet planned generation and we expect to have enough in 2007. In the future we may need to purchase additional allowances. We expect to recover the cost of emission allowances through the RECA. The pricing of emissions allowances is unpredictable and may change over time.

On March 15, 2005, the EPA issued the Clean Air Mercury Rule. The rule caps permanently, and seeks to reduce, the amount of mercury that may be emitted from coal-fired power plants. The Clean Air Mercury Rule requires reductions of mercury in two phases, the first starting in 2010. To comply with this rule we will need to install and maintain additional equipment at our coal-fired units. Several different environmental groups and states are challenging this rule in court, which could potentially delay its implementation. To date, no part of the Clean Air Mercury Rule has been stayed by any court although court cases remain open. Assuming this rule is not stayed, we will need to have installed and

certified by January 1, 2009, continuous emissions mercury monitoring systems on each coal-fired unit. We do not know what the costs to comply with the Clean Air Mercury Rule will be, but we believe they could be material.

Environmental requirements have been changing substantially. Accordingly, we may be required to further reduce emissions of presently regulated gases and substances, such as SO_2, NOx, particulate matter and mercury and we may be required to reduce or limit emissions of gases and substances not presently regulated (e.g., carbon dioxide (CO_2)). Proposals and bills in those respects include:

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

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

Environmental Projects

KCPL began installing additional equipment related to emissions controls at La Cygne in 2005. We currently expect our share of these capital costs through the scheduled completion in 2009 to be approximately $232.5 million. Additionally, we have identified the potential for up to $512.4 million of capital expenditures for environmental projects at our other power plants during the next seven to ten years. Our estimated costs of these projects have increased since we first announced these programs. These amounts could increase further depending on the resolution of the EPA New Source Review described below and other factors. In addition to the capital investment, when we install such equipment, we will also incur significant annual expense to operate and maintain the equipment and the operation of the equipment reduces net production from our plants. The ECRR allows for the timely inclusion in rates of capital expenditures tied directly to environmental improvements required by the Clean Air Act. However, increased operating and maintenance costs, other than expenses related to production-related consumables, such as limestone, can be recovered only through a change in our base rates following a rate review.

The degree to which we will need to reduce emissions and the timing of when such emissions controls may be required is uncertain. Both the timing and the nature of required investments depend on specific outcomes that result from interpretation of regulations, new regulations, legislation, and the resolution of the EPA New Source Review described below. In addition, the availability of equipment and contractors can affect the timing and ultimate cost of equipment installation. We expect to recover such costs through the rates we charge our customers.

EPA New Source Review

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

The EPA requested information from us under Section 114 regarding projects and maintenance activities that have been conducted since 1980 at 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. 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 the ECRR. 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. We are not able to estimate the possible loss or range of loss at this time.

Manufactured Gas Sites

We have been associated with a number of former manufactured gas sites located in Kansas and Missouri. 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. Pursuant to an environmental indemnity agreement with ONEOK, the current owner of some of the sites, our liability for twelve of the 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. We have sole responsibility for remediation with respect to three sites.

Our liability for former manufactured gas sites in Missouri is limited by an environmental indemnity with the purchaser of our former Missouri assets in the amount of $7.5 million.

SEASONALITY

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

EMPLOYEES

As of February 15, 2007, we had 2,223 employees. Our current contract with Local 304 and Local 1523 of the International Brotherhood of Electrical Workers extends through June 30, 2008. The contract covered 1,279 employees as of February 15, 2007.

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.westarenergy.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 Securities and Exchange Commission (SEC). The information contained on our Internet website is not part of this document.

EXECUTIVE OFFICERS OF THE COMPANY

Name	Age	Present Office	Other Offices or Positions Held During the Past Five Years
James S. Haines, Jr.	60	Director and Chief Executive Officer (since March 2006)	**Westar Energy, Inc.** Director, Chief Executive Officer and President (December 2002 to March 2006) **The University of Texas at El Paso** Adjunct Professor and Skov Professor of Business Ethics (January 2002 to Present) **El Paso Electric Company** Director and Vice Chairman (December 2001 to November 2002)
William B. Moore	54	President and Chief Operating Officer (since March 2006)	**Westar Energy, Inc.** Executive Vice President and Chief Operating Officer (December 2002 to March 2006) **Saber Partners, LLC** Senior Managing Director and Senior Advisor (October 2000 to December 2002)
Mark A. Ruelle	45	Executive Vice President and Chief Financial Officer (since January 2003)	**Sierra Pacific Resources, Inc.** President, Nevada Power Company (June 2001 to May 2002)
Douglas R. Sterbenz	43	Executive Vice President, Generation and Marketing (since March 2006)	**Westar Energy, Inc.** Senior Vice President, Generation and Marketing (October 2001 to March 2006)
Bruce A. Akin	42	Vice President, Administrative Services (since December 2001)	
Larry D. Irick	50	Vice President, General Counsel and Corporate Secretary (since February 2003)	**Westar Energy, Inc.** Vice President and Corporate Secretary (December 2001 to February 2003)
James J. Ludwig	48	Vice President, Regulatory and Public Affairs (since March 2006)	**Westar Energy, Inc.** Vice President, Public Affairs (January 2003 to March 2006)
Lee Wages	58	Vice President, Controller (since December 2001)	

Executive officers serve at the pleasure of the board of directors. There are no family relationships among any of the executive officers, nor any arrangements or understandings between any executive officer and other persons pursuant to which he was appointed as an executive officer.

ITEM 1A. RISK FACTORS

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

Our Revenues Depend Upon Rates Determined by the KCC

The KCC regulates many aspects of our business and operations, including the rates that we charge customers for retail 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 and a return on capital investments. Using this approach, the KCC sets rates at a level calculated to recover such costs and a permitted return on investment. Other parties to a rate review or the KCC staff may contend that our rates are excessive. Effective January 2006, the KCC authorized changes that left our base rates virtually unchanged but approved various changes to our rate structure that allow some adjustment to our prices. The KCC approved the RECA, which allows us to recover cost of fuel for generation and purchased power expense (less margins earned on wholesale sales). It also authorized us to implement the ECRR, which allows us to change our rates to reflect the impact of capital expenditures made to upgrade our equipment to environmental standards required by the Clean Air Act.

Our Costs May Not be Fully Recovered in Retail Rates

Except to the extent the KCC permits us to modify our prices by using specific adjustments and riders such as the RECA and the ECRR, once established by the KCC, our rates generally remain fixed until changed in a subsequent rate review. We may apply to change our rates or intervening parties may request that the KCC review our rates for possible adjustment, subject to any limitations that may have been ordered by the KCC.

Equipment Failures and Other External Factors Can Adversely Affect Our Results

The generation and transmission of electricity requires the use of expensive and complicated equipment. While we have maintenance programs in place, generating plants are subject to unplanned outages because of equipment failure. In these events, we must either produce replacement power from our other, usually less efficient, units or purchase power from others at unpredictable and potentially higher cost in order to meet our sales obligations. In addition, equipment failure can limit our ability to make opportunistic sales to wholesale customers.

Fuel Deliveries Can Be Interrupted or Slowed and Transmission Systems May Be Constrained

Coal deliveries from the PRB region of Wyoming, the primary source for our coal, can be interrupted or can be slowed due to rail traffic congestion, equipment or track failure, or due to loading problems at the mines. This may require that we implement coal conservation efforts and/or take other compensating measures. We experienced these problems and conserved coal to varying degrees in 2005 and 2006. These measures may include, but are not limited to, reducing coal consumption by revising normal dispatch of generation units, purchasing power or using more expensive power to serve customers and decreasing or, if necessary, eliminating opportunistic wholesale sales. In addition, decisions or mistakes by other utilities may adversely affect our ability to use transmission lines to deliver or import power, thus subjecting us to unexpected expenses or to the cost and uncertainty of public policy initiatives. These factors, along with the prices and price volatility of fuel and wholesale electricity are largely beyond our control. Costs that are not recovered through the RECA could have a material adverse effect on our consolidated earnings, cash flows and financial position. We engage in energy marketing transactions to reduce risk from market fluctuations, enhance system reliability and increase profits. The events mentioned above could reduce our ability to participate in energy marketing opportunities, which could reduce our profits.

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

On January 22, 2004, the EPA notified 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 at Jeffrey Energy Center and at certain of our other coal-fired power plants, the associated cost of which could be material.

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

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

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

We currently apply the accounting principles of Statement of Financial Accounting Standard (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation," to our regulated business. As of December 31, 2006, we had recorded $476.0 million of regulatory assets, net of regulatory liabilities. In the event we determined that we could no longer apply the principles of SFAS No. 71, either as: (i) a result of the establishment of retail competition in our service territory; (ii) a change in the regulatory approach for setting rates from cost-based ratemaking to another form of ratemaking; or (iii) other regulatory actions that restrict cost recovery to a level insufficient to recover costs, we would be required to record a charge against income in the amount of the remaining unamortized net regulatory assets. Such an action would materially reduce our shareholders' equity. We periodically review these criteria to ensure the continuing application of SFAS No. 71 is appropriate. Based upon current evaluation of the various factors that are expected to impact future cost recovery, we believe that our regulatory assets are probable of recovery.

We Face Financial Risks Associated With Wolf Creek

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

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

				Unit Capacity (MW) By Owner		
Name/Location	Unit No.	Year Installed	Principal Fuel	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	—	151.0	151.0
	2	1967	Gas – Oil	—	374.0	374.0
Combustion Turbines	1	2000	Gas	74.0	—	74.0
	2	2000	Gas	72.0	—	72.0
	3	2001	Gas	146.0	—	146.0
Diesel Generator	1	1969	Diesel	—	3.0	3.0
Hutchinson Energy Center:						
Hutchinson, Kansas						
Steam Turbine	4	1965	Gas – Oil	166.0	—	166.0
Combustion Turbines	1	1974	Gas	51.0	—	51.0
	2	1974	Gas	51.0	—	51.0
	3	1974	Gas	56.0	—	56.0
	4	1975	Diesel	75.0	—	75.0
Diesel Generator	1	1983	Diesel	3.0	—	3.0
Jeffrey Energy Center (84%):						
St. Marys, Kansas						
Steam Turbines	1 [a]	1978	Coal	467.0	146.0	613.0
	2 [a]	1980	Coal	467.0	146.0	613.0
	3 [a]	1983	Coal	467.0	146.0	613.0
Wind Turbines	1 [a]	1999	—	0.5	0.1	0.6
	2 [a]	1999	—	0.5	0.1	0.6
La Cygne Station (50%):						
La Cygne, Kansas						
Steam Turbines	1 [a]	1973	Coal	—	370.0	370.0
	2 [b]	1977	Coal	—	341.0	341.0
Lawrence Energy Center:						
Lawrence, Kansas						
Steam Turbines	3	1954	Coal	49.0	—	49.0
	4	1960	Coal	110.0	—	110.0
	5	1971	Coal	373.0	—	373.0
Murray Gill Energy Center:						
Wichita, Kansas						
Steam Turbines	1	1952	Gas	—	39.0	39.0
	2	1954	Gas – Oil	—	63.0	63.0
	3	1956	Gas – Oil	—	95.0	95.0
	4	1959	Gas – Oil	—	99.0	99.0
Neosho Energy Center:						
Parsons, Kansas						
Steam Turbine	3	1954	Gas – Oil	—	66.0	66.0
Spring Creek Energy Center						
Edmond, Oklahoma						
Combustion Turbines	1	2001 [c]	Gas	75.0	—	75.0
	2	2001	Gas	75.0	—	75.0
	3	2001	Gas	75.0	—	75.0
	4	2001	Gas	75.0	—	75.0
State Line (40%):						
Joplin, Missouri						
Combined Cycle	2-1 [a]	2001	Gas	65.0	—	65.0
	2-2 [a]	2001	Gas	65.0	—	65.0
	2-3 [a]	2001	Gas	74.0	—	74.0

Name/Location	Unit No.	Year Installed	Principal Fuel	Unit Capacity (MW) By Owner: Westar Energy	KGE	Total Company
Tecumseh Energy Center:						
Tecumseh, Kansas						
Steam Turbines	7	1957	Coal	74.0	—	74.0
	8	1962	Coal	130.0	—	130.0
Combustion Turbines	1	1972	Gas	19.0	—	19.0
	2	1972	Gas	19.0	—	19.0
Wolf Creek Generating Station (47%):						
Burlington, Kansas						
Nuclear	1[a]	1985	Uranium	—	548.0	548.0
Total				3,446.0	2,587.2	6,033.2

[a] *We jointly own Jeffrey Energy Center (84%), La Cygne unit 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 La Cygne unit 2 generating unit.*

[c] *We acquired Spring Creek Energy Center in 2006.*

We own approximately 6,100 miles of transmission lines, approximately 23,700 miles of overhead distribution lines and approximately 3,800 miles of underground distribution lines.

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

ITEM 3. LEGAL PROCEEDINGS

Information on other legal proceedings is set forth in Notes 3, 14, 16, 17 and 18 of the Notes to Consolidated Financial Statements, "Rate Matters and Regulation," "Commitments and Contingencies — EPA New Source Review," "Legal Proceedings," "Ongoing Investigations — Department of Labor Investigation," and "Potential Liabilities to David C. Wittig and Douglas T. Lake," respectively, which are incorporated herein by reference.

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

None.

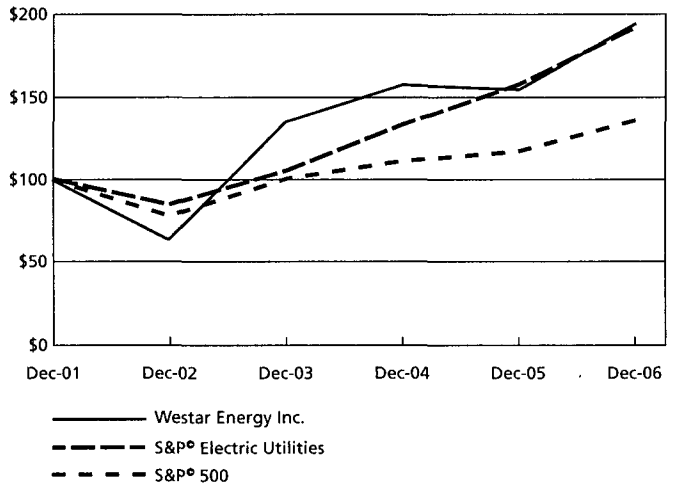
PART II

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

STOCK PERFORMANCE GRAPH

The following performance graph compares the performance of our common stock during the period that began on December 31, 2001 and ended on December 31, 2006 to the Standard & Poor's 500 Index and the Standard & Poor's Electric Utility Index. The graph assumes a $100 investment in our common stock and in each of the indices at the beginning of the period and a reinvestment of dividends paid on such investments throughout the period.

CUMULATIVE TOTAL RETURN
Based upon an initial investment of $100 on December 31, 2001 with dividends reinvested



	Dec-2001	Dec-2002	Dec-2003	Dec-2004	Dec-2005	Dec-2006
Westar Energy Inc.	$100	$63	$135	$158	$155	$195
S&P 500	$100	$78	$100	$111	$117	$135
S&P Electric Utilities	$100	$85	$105	$133	$157	$193

STOCK TRADING

Our common stock is listed on the New York Stock Exchange and traded under the ticker symbol WR. As of February 15, 2007, there were 26,449 common shareholders of record. For information regarding quarterly common stock price ranges for 2006 and 2005, see Note 23 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 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. During 2006 our board of directors declared four quarterly dividends, each at $0.25 per share, reflecting an annual dividend of $1.00 per share. On February 21, 2007, our board of directors declared a quarterly dividend of $0.27 per share on our common stock payable to shareholders on April 2, 2007. The indicated annual dividend rate is $1.08 per share.

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 were not limited by any such restrictions during 2006. We provide further information on these restrictions in Note 20 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.

ITEM 6. SELECTED FINANCIAL DATA

Year Ended December 31,	2006	2005	2004	2003	2002[b]
			(In Thousands)		
Income Statement Data:					
Sales	$ 1,605,743	$ 1,583,278	$ 1,464,489	$ 1,461,143	$ 1,423,151
Income from continuing operations before accounting change[a]	165,309	134,868	100,080	162,915	88,816
Earnings (loss) available for common stock	164,339	134,640	177,900	84,042	(793,400)
As of December 31,	**2006**	**2005**	**2004**	**2003**	**2002**
			(In Thousands)		
Balance Sheet Data:					
Total assets	$ 5,455,175	$ 5,210,069	$ 5,001,144	$ 5,672,520	$ 6,756,666
Long-term obligations and mandatorily redeemable preferred stock[c]	1,580,108	1,681,301	1,724,967	2,259,880	3,222,556
Year Ended December 31,	**2006**	**2005**	**2004**	**2003**	**2002[b]**
Common Stock Data:					
Basic earnings per share available for common stock from continuing operations before accounting change	$ 1.88	$ 1.54	$ 1.19	$ 2.24	$ 1.23
Basic earnings (loss) per share available for common stock	$ 1.88	$ 1.55	$ 2.14	$ 1.16	$ (11.06)
Dividends declared per share	$ 1.00	$ 0.92	$ 0.80	$ 0.76	$ 1.20
Book value per share	$ 17.61	$ 16.31	$ 16.13	$ 13.98	$ 13.41
Average equivalent common shares outstanding (in thousands)[d]	87,510	86,855	82,941	72,429	71,732

[a] *In 2002, we recognized a cumulative effect of accounting change of $623.7 million due to recording an impairment charge for goodwill.*

[b] *Our losses in 2002 were attributable primarily to impairment charges recorded for Protection One, Inc. and Protection One Europe.*

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

[d] *In 2004, we issued and sold approximately 12.5 million shares of common stock realizing net proceeds of $245.1 million.*

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.

In Management's Discussion and Analysis, we discuss our general financial condition, significant changes that occurred during 2006, and our operating results for the years ended December 31, 2006, 2005 and 2004. As you read Management's Discussion and Analysis, please refer to our consolidated financial statements and the accompanying notes, which contain our operating results.

SUMMARY OF SIGNIFICANT ITEMS

Overview

Several significant items have impacted or may impact us and our operations since January 1, 2006:

- Portions of the 2005 KCC Order were challenged and ultimately reversed by the KCC. See "— Changes in Rates" below for additional information;
- We implemented the RECA which allows us to adjust our prices to correspond with changes in the costs we incur for fuel and purchased power;
- We purchased a 300 MW peaking power plant, announced plans to build a 600 MW peaking power plant and announced plans to expand our electric transmission network. See "— Increased Capacity and Future Plans" below for additional information;
- We plan to install emissions control equipment at Jeffrey Energy Center and some of our other coal plants. Due to increasing prices of labor and materials, we increased the estimated costs of installing this equipment at our power plants. For additional information, see "— Liquidity and Capital Resources — Future Cash Requirements";
- The convictions of David C. Wittig and Douglas T. Lake were overturned. See "— Convictions of David C. Wittig and Douglas T. Lake Overturned" below for additional information;
- We received $18.9 million in proceeds from corporate-owned life insurance in 2006 and $9.5 million in 2005; and
- We took measures, including the acquisition of additional rail cars and the conservation of coal, that when coupled with changes at the mines and with the railroads, resulted in improved coal deliveries. See "— Coal Inventory and Delivery" below for additional information.

Changes in Rates

In accordance with a 2003 KCC Order, on May 2, 2005, we filed applications with the KCC for it to review our retail electric rates. The 2005 KCC Order authorized changes in our rates, which we began billing in the first quarter of 2006, and approved various other changes to our rate structures. In April 2006, interveners filed appeals with the Kansas Court of Appeals challenging various aspects of the 2005 KCC Order. On July 7, 2006, the Kansas Court of Appeals reversed and remanded for further consideration by the KCC three elements of the 2005 KCC Order. The balance of the 2005 KCC Order was upheld.

On February 8, 2007, the KCC issued an order in response to the Kansas Court of Appeals' decision regarding the 2005 KCC Order. In its February 8, 2007 Order the KCC: (i) confirmed its original decision regarding its treatment of the La Cygne unit 2 sale-leaseback transaction; (ii) in lieu of a transmission delivery charge, ruled that it intends to permit us to recover our transmission related costs in a manner similar to how we recover our other costs; and (iii) reversed itself with regard to the inclusion in depreciation rates of a component for terminal net salvage. The February 8, 2007 KCC Order requires us to refund to our customers the amount we have collected related to terminal net salvage. We have recorded a regulatory liability at December 31, 2006 in the amount of $16.4 million related to this item.

Increased Capacity and Future Plans

On October 31, 2006, we purchased a 300 MW electric generation facility and related assets from ONEOK Energy Services Company, L.P. (OESC) for $53.0 million. As part of this transaction, we entered into an agreement to provide OESC with 75 MW of capacity through 2015.

In August 2006, we announced plans to build a new natural gas-fired combustion turbine peaking power plant near Emporia in Lyon County, Kansas. We expect the new plant, which we have named the Emporia Energy Center, to have an initial generating capacity of up to 300 MW, with additional capacity to be added in a second phase, bringing the total capacity to approximately 600 MW. We expect the total investment in the plant to be about $318 million. We plan to begin construction on the new plant in the spring of 2007. The initial phase of the plant is scheduled to begin operation in the summer of 2008.

In September 2006, we announced plans to build a transmission line from our Gordon Evans Energy Center northwest of Wichita, Kansas, to a new substation near Hutchison, Kansas, then onto our Summit substation near Salina, Kansas, a distance totaling

approximately 86 miles. In January 2007, we filed an application with the KCC to request permission to build the line. Kansas law requires the KCC to issue an order within 120 days of our filing regarding our application. If the KCC issues a permit for us to proceed, we expect to complete construction in 2009. Our preliminary cost estimate for the project is $80 million to $100 million. This estimate could change materially as engineering and construction proceed. In addition to this line, we plan additional expansions to our electric transmission network in Kansas. These include a new line from our Rose Hill substation near Wichita to the Kansas-Oklahoma border, where we expect to interconnect with new facilities built by an Oklahoma-based utility, and a new line from our Jeffrey Energy Center to an existing substation about 15 miles south of Topeka, Kansas.

Convictions of David C. Wittig and Douglas T. Lake Overturned

On September 12, 2005, David C. Wittig, our former chairman of the board, president and chief executive officer, and Douglas T. Lake, our former executive vice president, chief strategic officer and member of the board, were convicted on various criminal charges by a jury in a trial held in U.S. District court in Kansas. The jury also determined that Mr. Wittig and Mr. Lake should forfeit to the United States certain property that it determined was derived from their criminal conduct. The court subsequently awarded us certain of the property forfeited by Mr. Wittig and Mr. Lake. On January 5, 2007, the U.S. Tenth Circuit Court of Appeals overturned these convictions and forfeiture orders. At December 31, 2006, we had accrued liabilities totaling approximately $74.8 million for compensation not yet paid to Mr. Wittig and Mr. Lake under various plans, and we had also accrued approximately $9.9 million for legal fees and expenses incurred by Mr. Wittig and Mr. Lake in the defense of these charges and related appeals. We believe Mr. Wittig and Mr. Lake are not entitled to this compensation. This dispute, and claims Mr. Wittig and Mr. Lake have made against us, are the subject of an arbitration that has been stayed pending the resolution of the criminal proceedings. We also believe the amounts sought by Mr. Wittig and Mr. Lake for legal fees and expenses are unreasonable. These disputes are also the subject of litigation. We are unable to predict whether the government will retry the criminal charges against Mr. Wittig and Mr. Lake or the outcome of these matters, including their ultimate impact on our results of operations. For additional information, see Note 18 of the Notes to Consolidated Financial Statements, "Potential Liabilities to David C. Wittig and Douglas T. Lake."

Coal Inventory and Delivery

Coal deliveries from the Powder River Basin region of Wyoming to our coal-fired generating stations improved in 2006; however, they continue to be slower than historical averages due primarily to issues at the coal mines and with the rail delivery system. During 2005 and continuing in 2006, we implemented compensating measures based on delivery cycle times, our assumptions about future delivery cycle times, fuel usage and planned inventory levels. We may continue to use these measures as conditions warrant. The compensating measures include, but are not limited to: reducing coal consumption during certain periods, revising normal operational dispatch of our generating units, purchasing power from others, reducing wholesale sales and leasing additional rail cars. The effects of additional purchased power expense and the reduction in sales due to slower coal deliveries have been partially offset by higher market-based wholesale sales prices.

CRITICAL ACCOUNTING ESTIMATES

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

Regulatory Accounting

We currently apply accounting standards for our regulated utility operations that recognize the economic effects of rate regulation in accordance with SFAS No. 71. Accordingly, we have recorded regulatory assets and liabilities when required by a regulatory order or based on regulatory precedent. Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery in utility rates. Regulatory liabilities represent probable future reductions in revenue or refunds to customers.

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

Pension and Post-retirement Benefit Plans Actuarial Assumptions

We and Wolf Creek 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," SFAS No. 106, "Employers' Accounting for Post-retirement Benefits Other Than Pensions" and SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Post-retirement Plans — An Amendment of FASB Statements No. 87, 88, 106, and 132(R)."

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 plans 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% change in our pension plan discount rate, salary scale and rate of return on plan assets.

Actuarial Assumption	Change in Assumption	Annual Change in Projected Benefit Obligation	Annual Change in Pension Liability/ Asset	Annual Change in Projected Pension Expense
			(In Thousands)	
Discount rate	0.5% decrease	$46,609	$46,609	$4,697
	0.5% increase	(43,650)	(43,650)	(4,616)
Salary scale	0.5% decrease	(11,536)	(11,536)	(1,153)
	0.5% increase	11,735	11,735	1,165
Rate of return on plan assets	0.5% decrease	—	—	2,455
	0.5% increase	—	—	(2,455)

We recorded pension expense of approximately $21.4 million in 2006, $12.2 million in 2005 and $5.1 million in 2004. These amounts reflect the pension expense of Westar Energy and our 47% responsibility for the pension expense of Wolf Creek. Pension expense increases are due primarily to the amortization of investment losses from prior years that are recognized on a rolling four-year average basis and changes in assumptions including lower discount rates, lower returns on assets, increases in salaries and updated mortality tables. Pension expense for 2007 is expected to be approximately $20.1 million.

The following table shows the annual impact of a 0.5% change in the discount rate and rate of return on plan assets on our post-retirement benefit plans other than pension plans.

Actuarial Assumption	Change in Assumption	Annual Change in Projected Benefit Obligation	Annual Change in Post-retirement Liability/ Asset	Annual Change in Projected Post-retirement Expense
			(In Thousands)	
Discount rate	0.5% decrease	$7,403	$7,403	$449
	0.5% increase	(7,013)	(7,013)	(454)
Rate of return on plan assets	0.5% decrease	—	—	222
	0.5% increase	—	—	(219)

Revenue Recognition — Energy Sales

We record revenue as electricity is delivered. Amounts delivered to individual customers are determined through the systematic monthly readings of customer meters. At the end of each month, the electric usage from the last meter reading is estimated and corresponding unbilled revenue is recorded.

The accuracy of the unbilled revenue estimate is affected by factors that include fluctuations in energy demands, weather, line losses and changes in the composition of customer classes. We had estimated unbilled revenue of $38.4 million as of December 31, 2006 and $42.1 million as of December 31, 2005.

We account for energy marketing derivative contracts under the mark-to-market method of accounting. Under this method, we recognize changes in the value of contracts in our portfolio as gains or losses in the period of change. With the exception of contracts for fuel that we purchase to produce energy in our power plants, we include the net mark-to-market change in sales on our consolidated statements of income. We record the resulting unrealized gains and losses as energy marketing long-term or short-term assets and liabilities on our consolidated balance sheets as appropriate. We use quoted market prices to value our energy marketing derivative contracts when such data is 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 value 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 the fair value of energy marketing and fuel contracts that were outstanding as of December 31, 2006, their sources and maturity periods.

	Fair Value of Contracts
	(In Thousands)
Net fair value of contracts outstanding as of December 31, 2005	$117,929
Contracts outstanding at the beginning of the period that were realized or otherwise settled during the period	(44,239)
Changes in fair value of contracts outstanding at the beginning and end of the period	(61,536)
Fair value of new contracts entered into during the period	8,471
Fair value of contracts outstanding as of December 31, 2006[a]	$ 20,625

[a] *Approximately $12.8 million of the fair value of fuel supply contracts is recognized as a regulatory liability.*

The sources of the fair values of the financial instruments related to these contracts as of December 31, 2006 are summarized in the following table.

	Fair Value of Contracts at End of Period		
Sources of Fair Value	Total Fair Value	Maturity Less Than 1 Year	Maturity 1-3 Years
		(In Thousands)	
Prices provided by other external sources (swaps and forwards)	$13,091	$ 8,994	$ 4,097
Prices based on option pricing models (options and other)[a]	7,534	992	6,542
Total fair value of contracts outstanding	$20,625	$ 9,986	$10,639

[a] *Options are priced using a series of techniques, such as the Black 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 losses, operating losses and tax credit carryforwards. However, when we believe we do not or will not have sufficient 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 we determine, based on available evidence that it is unlikely that we will realize some portion or all of the deferred tax asset. We report the effect of a change in the valuation allowance in the current period tax expense.

Asset Retirement Obligations

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

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

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

Contingencies and Litigation

We are currently involved in certain legal proceedings and have estimated the probable cost for the resolution of these claims. These estimates are based on an analysis of potential results, assuming a combination of litigation and settlement strategies. It is possible that our future results could be materially affected by changes in our assumptions. See Note 16 of the Notes to Consolidated Financial Statements, "Legal Proceedings," for more detailed information.

OPERATING RESULTS

We evaluate operating results based on earnings 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 revenue subject to refund.

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

Market-based wholesale: Sales of energy to wholesale customers, the rates for which are generally based on prevailing market prices as allowed by our FERC approved market-based tariff, or where not permitted, pricing is based on incremental cost plus a permitted margin. This category also includes changes in valuations of contracts that have yet to settle.

Energy marketing: Includes: (i) transactions based on market prices with volumes not related to the production of our generating assets or the demand of our retail customers; (ii) financially settled products and physical transactions sourced outside our control area; and (iii) changes in valuations for contracts that have yet to settle that may not be recorded in tariff- or market-based wholesale revenues.

Transmission: Reflects transmission revenues, 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 economy of our service area and competitive forces. Our wholesale sales are impacted by, among other factors, demand, cost and availability of fuel and purchased power, price volatility, available generation capacity and transmission availability. Changing weather affects the amount of electricity our customers use. Hot summer temperatures and cold winter temperatures prompt more demand, especially among our residential customers. Mild weather serves to reduce customer demand.

2006 Compared to 2005

Below we discuss our operating results for the year ended December 31, 2006 compared to the results for the year ended December 31, 2005. Changes in results of operations are as follows.

Year Ended December 31,	2006	2005	Change	% Change
	(In Thousands, Except Per Share Amounts)			
SALES:				
Residential	$ 486,107	$ 458,806	$27,301	6.0
Commercial	438,342	404,590	33,752	8.3
Industrial	266,922	242,383	24,539	10.1
Other retail	(32,098)	376	(32,474)	[b]
Total Retail Sales	1,159,273	1,106,155	53,118	4.8
Tariff-based wholesale	195,428	185,598	9,830	5.3
Market-based wholesale	101,217	145,628	(44,411)	(30.5)
Energy marketing	40,113	47,089	(6,976)	(14.8)
Transmission[a]	83,764	76,591	7,173	9.4
Other	25,948	22,217	3,731	16.8
Total Sales	1,605,743	1,583,278	22,465	1.4
OPERATING EXPENSES:				
Fuel and purchased power	483,959	528,229	(44,270)	(8.4)
Operating and maintenance	463,785	437,741	26,044	5.9
Depreciation and amortization	180,228	150,520	29,708	19.7
Selling, general and administrative	171,001	166,060	4,941	3.0
Total Operating Expenses	1,298,973	1,282,550	16,423	1.3
INCOME FROM OPERATIONS	306,770	300,728	6,042	2.0
OTHER INCOME (EXPENSE):				
Investment earnings	9,212	11,365	(2,153)	(18.9)
Other income	18,000	9,948	8,052	80.9
Other expense	(13,711)	(17,580)	3,869	22.0
Total Other Income	13,501	3,733	9,768	261.7
Interest expense	98,650	109,080	(10,430)	(9.6)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	221,621	195,381	26,240	13.4
Income tax expense	56,312	60,513	(4,201)	(6.9)
INCOME FROM CONTINUING OPERATIONS	165,309	134,868	30,441	22.6
Results of discontinued operations, net of tax	—	742	(742)	(100.0)
NET INCOME	165,309	135,610	29,699	21.9
Preferred dividends	970	970	—	—
EARNINGS AVAILABLE FOR COMMON STOCK	$ 164,339	$ 134,640	$29,699	22.1
BASIC EARNINGS PER SHARE	$ 1.88	$ 1.55	$ 0.33	21.3

[a] ***Transmission:*** *Includes an SPP network transmission tariff. In 2006, our SPP network transmission costs were approximately $76.0 million. This amount, less approximately $10.1 million that was retained by the SPP as administration cost, was returned to us as revenue. In 2005, our SPP network transmission costs were approximately $66.2 million with an administration cost of $5.5 million retained by the SPP.*

[b] *Change greater than 1000%*

The following table reflects changes in electric sales volumes, as measured by thousands of megawatt hours (MWh) of electricity. No sales volumes are shown for energy marketing, transmission or other. Energy marketing activities are unrelated to the amount of electricity we generate at our generating plants.

Year Ended December 31,	2006	2005	Change	% Change
	(Thousands of MWh)			
Residential	6,456	6,384	72	1.1
Commercial	7,185	7,151	34	0.5
Industrial	5,824	5,581	243	4.4
Other retail	93	101	(8)	(7.9)
Total Retail	19,558	19,217	341	1.8
Tariff-based wholesale	5,505	5,490	15	0.3
Market-based wholesale	1,913	2,950	(1,037)	(35.2)
Total	26,976	27,657	(681)	(2.5)

The increase in retail sales reflects the change in rates, including the effect of implementing the RECA, and warmer weather. When measured by cooling degree days, the weather during 2006 was 2% warmer than during 2005 and approximately 16% warmer than the 20-year average. The increase in industrial sales was due primarily to additional oil refinery load. The change in other retail sales reflects the recognition in 2006 of revenue subject to refund, of which: (i) $19.9 million is due to the difference between estimated fuel and purchased power costs billed to our customers and actual fuel and purchased power costs incurred for our Westar Energy customers; (ii) $3.3 million is due to amounts associated with a transmission delivery charge approved by the KCC in its 2005 Order; (iii) $4.0 million collected for property taxes in excess of our actual property taxes obligations; and (iv) $16.4 million related to amounts we collected in rates related to terminal net salvage that the KCC's February 8, 2007 Order requires us to refund. The revenue subject to refund was partially offset by our having stopped accruing for rebates to customers in December 2005.

We made tariff-based sales in 2006 at an average price that was about 5% higher than the price of these sales in 2005. We attribute about $1.3 million, or 14%, of the increase in tariff-based wholesale sales to higher prices reflecting an adjustment for our fuel costs as permitted in FERC tariffs.

Our market-based wholesale sales and sales volumes decreased in 2006 due primarily to our having conserved coal inventories, but the average price per MWh that we received for these sales in 2006 was about 7% higher than in 2005.

The change in fuel and purchased power expense is the result of changing volumes produced and purchased, prevailing market prices and contract provisions that allow for price changes. We burned about 4% less fuel in our generating plants in 2006, due primarily to our having conserved coal inventories. We also used less expensive generation. In addition, during 2006 we deferred as a regulatory asset $6.9 million for the difference between the estimated fuel and purchased power costs that we billed our KGE

customers and our higher actual fuel and purchased power costs that we are allowed to collect under the terms of the RECA. As a result, our fuel expense was $45.5 million lower in 2006 than in 2005. We also experienced a $1.2 million increase in our purchased power expense due primarily to our having purchased 9% greater volumes than in 2005.

We experienced an increase in our operating and maintenance expense due primarily to four factors: (i) the amortization of $10.7 million of previously deferred storm restoration expenses as authorized by the 2005 KCC Order; (ii) a $9.9 million increase in SPP network transmission costs; (iii) a $4.7 million increase in taxes other than income taxes due primarily to higher property taxes; and (iv) an increase in maintenance expenses for outages at La Cygne and the Gordon Evans Energy Center. These higher expenses were partially offset by a $5.4 million reduction in the lease expense related to La Cygne unit 2. Operating and maintenance expense in 2005 included a $10.4 million loss as a result of the decrease in the present value of previously disallowed plant costs associated with the original construction of Wolf Creek due to the extension of the recovery period.

We experienced an increase in our depreciation and amortization expense of $29.7 million. This increase was due primarily to the reduction of depreciation expense of $20.1 million in 2005 due to the establishment of a regulatory asset for the differences between the depreciation rates we used for financial reporting purposes and the depreciation rates authorized by the KCC for the period of August 2001 to March 2002. Provisions of the 2005 KCC Order allowed us to record this regulatory asset.

Selling, general and administrative expenses increased due primarily to increased employee pension and benefit costs. Partially offsetting these increases were lower legal fees associated with matters having to deal with former management and a decline in insurance costs.

Other income increased due primarily to corporate-owned life insurance. We received $16.4 million in income from corporate-owned life insurance in 2006 compared to $7.2 million in 2005. Associated with our having terminated an accounts receivable sales facility we experienced a $3.9 million decrease in other expense.

Interest expense decreased due primarily to a $16.7 million reduction in interest expense on long-term debt due primarily to a lower long-term debt balance and lower interest rates resulting from the refinancing activities discussed in detail in "— Liquidity and Capital Resources — Debt Financings." This decline was partially offset by an increase of $6.3 million in interest expense on short-term debt due to increased borrowings under our revolving credit facility.

The decrease in income tax expense is due primarily to the utilization of previously unrecognized capital loss carryforwards to offset realized capital gains and increases in non-taxable income from corporate-owned life insurance.

2005 Compared to 2004

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

Year Ended December 31,	2005	2004	Change	% Change
	(In Thousands, Except Per Share Amounts)			
SALES:				
Residential	$ 458,806	$ 425,150	$ 33,656	7.9
Commercial	404,590	386,991	17,599	4.5
Industrial	242,383	239,518	2,865	1.2
Other retail	376	(46)	422	917.4
Total Retail Sales	1,106,155	1,051,613	54,542	5.2
Tariff-based wholesale	185,598	143,868	41,730	29.0
Market-based wholesale	145,628	140,465	5,163	3.7
Energy marketing	47,089	26,321	20,768	78.9
Transmission[a]	76,591	77,540	(949)	(1.2)
Other	22,217	24,682	(2,465)	(10.0)
Total Sales	1,583,278	1,464,489	118,789	8.1
OPERATING EXPENSES:				
Fuel used for generation	430,426	353,617	76,809	21.7
Purchased power	97,803	66,171	31,632	47.8
Operating and maintenance	437,741	412,002	25,739	6.2
Depreciation and amortization	150,520	169,310	(18,790)	(11.1)
Selling, general and administrative	166,060	173,498	(7,438)	(4.3)
Total Operating Expenses	1,282,550	1,174,598	107,952	9.2
INCOME FROM OPERATIONS	300,728	289,891	10,837	3.7
OTHER INCOME (EXPENSE):				
Investment earnings	11,365	16,746	(5,381)	(32.1)
Loss on extinguishment of debt	—	(18,840)	18,840	100.0
Other income	9,948	2,756	7,192	261.0
Other expense	(17,580)	(14,879)	(2,701)	(18.2)
Total Other Income (Expense)	3,733	(14,217)	17,950	126.3
Interest expense	109,080	142,151	(33,071)	(23.3)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	195,381	133,523	61,858	46.3
Income tax expense	60,513	33,443	27,070	80.9
INCOME FROM CONTINUING OPERATIONS	134,868	100,080	34,788	34.8
Results of discontinued operations, net of tax	742	78,790	(78,048)	(99.1)
NET INCOME	135,610	178,870	(43,260)	(24.2)
Preferred dividends	970	970	—	—
EARNINGS AVAILABLE FOR COMMON STOCK	$ 134,640	$ 177,900	$(43,260)	(24.3)
BASIC EARNINGS PER SHARE	$ 1.55	$ 2.14	$ (0.59)	(27.6)

[a] ***Transmission:*** *Includes an SPP network transmission tariff. In 2005, our SPP network transmission costs were approximately $66.2 million. This amount, less approximately $5.5 million that was retained by the SPP as administration cost, was returned to us as revenue. In 2004, our SPP network transmission costs were approximately $66.6 million with an administration cost of $4.3 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 years ended December 31, 2005 and 2004. No sales volumes are shown for energy marketing, transmission or other. Energy marketing activities are unrelated to electricity we generate.

Year Ended December 31,	2005	2004	Change	% Change
	(Thousands of MWh)			
Residential	6,384	5,925	459	7.7
Commercial	7,151	6,867	284	4.1
Industrial	5,581	5,470	111	2.0
Other retail	101	102	(1)	(1.0)
Total Retail	19,217	18,364	853	4.6
Tariff-based wholesale	5,490	4,573	917	20.1
Market-based wholesale	2,950	4,115	(1,165)	(28.3)
Total	27,657	27,052	605	2.2

Residential and commercial sales and sales volumes increased due primarily to warmer weather during 2005 than experienced in 2004. When measured by cooling degree days, the weather during 2005 was 27% warmer than during 2004 and 6% above 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 warmer weather also contributed to the increased tariff-based wholesale sales and sales volumes. Additionally, about $2.7 million, or approximately 2%, of the increase in the tariff-based wholesale sales was due to the Wolf Creek outages. We sold more tariff-based wholesale power to KEPCo in accordance with a contract to supply replacement power when Wolf Creek is not available. We had more energy available from Jeffrey Energy Center, which also contributed to the increased tariff-based wholesale sales.

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

The change in energy marketing was due primarily to having more favorable changes in market valuations in 2005 compared to 2004 and due to favorable settlements of energy contracts in 2005.

Fuel expense increased due primarily to using more expensive sources of generation because of the lower unit availability of our more economical generating units.

Purchased power expense increased due primarily to a 35% increase in volumes purchased during 2005 as compared to 2004. This was due to the various outages or reduced operating capability at some of our generating units and the availability of economically priced power. At times, it was more economical to purchase power than to operate our available generating units. Also contributing to the increase in purchased power expense was a 9% higher average cost.

Operating and maintenance expense increased due to a number of factors, the largest of which was a $10.4 million write-off of disallowed plant costs pursuant to the 2005 KCC Order.

In addition, costs of operating and maintaining our distribution system increased $8.4 million due primarily to higher labor costs and additional maintenance projects. Also causing the operating and maintenance expense to increase was higher taxes other than income tax of $4.7 million, a $3.5 million charge to write off plant operating system development costs at Wolf Creek due to non-performance of the vendor developing the system and higher maintenance costs at our generating units of $2.8 million due to the outages as discussed above in "— Unit Availability." These higher expenses were partially offset by a $5.4 million decline in expense related to changes in the La Cygne unit 2 operating lease as discussed in Note 21 of the Notes to Consolidated Financial Statements, "Leases."

Depreciation expense decreased primarily because we established a regulatory asset for the depreciation differences between those used for financial statement purposes and regulatory rate making purposes from August 2001 to March 2002 pursuant to the December 28, 2005 KCC Order, which allowed us to record a reduction in depreciation expense of $20.1 million.

Selling, general and administrative expenses decreased due primarily to reduced legal fees and insurance costs. Increased employee pension and benefit costs partially offset the decrease.

During 2004, we recognized a loss of $16.1 million in connection with the redemption of some of our senior unsecured notes and a loss of $2.7 million in connection with the redemption of the Western Resources Capital I 7-7/8% Cumulative Quarterly Income Preferred Securities, Series A.

Other income during 2005 was higher due primarily to $7.2 million of income from corporate-owned life insurance, which was partially offset by higher interest expense associated with borrowings on corporate-owned life insurance.

Interest expense decreased during 2005 due to lower debt balances and lower interest rates due to the refinancing activities as discussed in detail in "— Liquidity and Capital Resources" below.

The increase in income tax expense reflects the increase in income from continuing operations before income taxes.

FINANCIAL CONDITION

A number of factors affected amounts recorded on our balance sheet as of December 31, 2006 compared to December 31, 2005.

Total restricted cash decreased due primarily to the return of $26.0 million of collateral we had previously been required to post related to a capacity and transmission agreement. In May 2006, Moody's Investors Service upgraded its credit ratings for our debt securities, which met conditions in the agreement that allowed the funds to be released.

Our accounts receivable balance increased by $55.1 million due primarily to our having terminated an accounts receivable sales facility during the year. This is discussed in Note 4 of the Notes to Consolidated Financial Statements, "Accounts Receivable Sales Program."

Inventories and supplies increased $46.1 million due primarily to increases in fuel stock. As a result of our coal conservation efforts and other measures we implemented to improve coal deliveries, we were able to build our coal inventories.

Due primarily to lower market valuations on our coal supply contract for Lawrence and Tecumseh Energy Centers the fair market value of our net energy marketing contracts decreased $97.3 million to $20.6 million as of December 31, 2006 compared to $117.9 million as of December 31, 2005.

Regulatory assets, net of regulatory liabilities, increased to $476.0 million at December 31, 2006, from $275.0 million at December 31, 2005. Total regulatory assets increased $172.0 million due primarily to the $186.3 million increase in deferred employee benefit costs for pension and post-retirement benefit obligations recognized pursuant to SFAS No. 158. Total regulatory liabilities decreased $29.0 million due primarily to the change in the market value of the coal supply contract for our Lawrence and Tecumseh Energy Centers as noted in the discussion of inventories above. As of December 31, 2006, we recorded a regulatory liability of $12.8 million compared with $117.7 million as of December 31, 2005 to recognize the mark-to-market value of our coal supply contracts. This decline was partially offset by a $32.7 million increase in the nuclear decommissioning regulatory liability as discussed in Note 15 of the Notes to Consolidated Financial Statements, "Asset Retirement Obligations," $19.9 million of revenue subject to refund for amounts collected from the RECA and $16.4 million for amounts collected related to terminal net salvage as discussed in Note 3 of the Notes to Consolidated Financial Statements.

Other current assets decreased $42.6 million due primarily to the manner in which we settled lawsuits discussed in detail in Note 16 of the Notes to Consolidated Financial Statements, "Legal Proceedings." As a result of settling the lawsuits and with our insurance carriers, pending actual cash distributions to the plaintiffs, we had recorded a receivable from our insurer, with an offsetting payable to the plaintiffs. Once payments were made to the plaintiffs, both the receivable and the payable were eliminated.

Other assets decreased $13.2 million due primarily to the elimination of the pension intangible asset of $17.6 million pursuant to the adoption of SFAS No. 158 and $10.2 million associated with the redemption of Guardian International, Inc. (Guardian) preferred stock. This decline was offset partially by a $7.3 million increase associated with assets acquired with the acquisition of the Spring Creek Energy Center.

As of December 31, 2006, we had no current maturities of long-term debt. Current maturities of long-term debt as of December 31, 2005 consisted of the $100.0 million outstanding aggregate principal amount of KGE 6.2% first mortgage bonds that we repaid in January 2006.

We increased our borrowings under the Westar Energy revolving credit facility. As a result our short-term debt increased $160.0 million. We used a portion of the borrowings to repay the KGE first mortgage bonds that were due in January 2006. In addition, we used borrowings under the revolving credit facility to meet our on-going operational needs.

Other current liabilities decreased $29.9 million due primarily to the disbursement of the funds for the settlement of lawsuits as discussed above and as detailed in Note 16 of the Notes to Consolidated Financial Statements, "Legal Proceedings." Upon rebating $10.0 million to customers in 2006, in fulfillment of a 2003 regulatory settlement, we reduced other current liabilities accordingly.

Accrued employee benefits increased $88.5 million due primarily to the additional pension and post-retirement benefit liabilities recorded in 2006 pursuant to the adoption of SFAS No. 158. For additional information, see Notes 12 of the Notes to Consolidated Financial Statements, "Employee Benefit Plans."

Asset retirement obligations decreased $45.7 million due primarily to the remeasurement of our asset retirement obligation for Wolf Creek based on its application for a license extension. For additional information, see Note 15 of the Notes to Consolidated Financial Statements, "Asset Retirement Obligations."

During 2006 we implemented SFAS No. 123R, which guides the accounting for equity-based compensation. This caused us to record changes in temporary equity, paid-in capital and unearned compensation. This is discussed in further detail in Note 12 of the Notes to Consolidated Financial Statements, "Employee Benefit Plans."

Accumulated other comprehensive income increased $41.1 million due primarily to the establishment of a regulatory asset for the pension liabilities that were previously charged to accumulated other comprehensive income.

LIQUIDITY AND CAPITAL RESOURCES

Overview

We believe we will have sufficient cash to fund future operations, debt maturities 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 and access to capital markets. Uncertainties affecting our ability to meet these cash 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.

Capital Resources

As of December 31, 2006, we had $18.2 million in unrestricted cash and cash equivalents. In addition, Westar Energy has a $500.0 million revolving credit facility against which $160.0 million had been borrowed and $32.0 million of letters of credit have been issued. This left $308.0 million available under this facility.

The Westar Energy and KGE mortgages each contain provisions restricting the amount of first mortgage bonds that can be issued by each entity. We must 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. As of December 31, 2006, based on an assumed interest rate of 6%, $378.8 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. As of December 31, 2006, based on an assumed interest rate of 6%, approximately $908.1 million principal amount of additional KGE first mortgage bonds could be issued under the most restrictive provisions in the mortgage.

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 decreased $97.9 million to $256.0 million in 2006, from $353.9 million in 2005. During 2006, we used $72.4 million to pay federal and state income taxes and made a $20.8 million contribution to our defined benefit pension trust. During 2005, we used approximately $33.1 million for system restoration costs related to the ice storm that affected our service territory in January 2005. We received $57.4 million in tax refunds during 2005.

Cash flows from operating activities increased $8.3 million to $353.9 million in 2005, from $345.6 million in 2004. During 2005, we received approximately $47.5 million more in tax refunds than we did during 2004. Cash paid for interest was $40.4 million lower in 2005 than in 2004 due primarily to our lower debt balances.

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 $344.9 million in 2006, $212.8 million in 2005 and $197.1 million in 2004 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.

Cash Flows used in Financing Activities

We received net cash flows from financing activities of $12.8 million in 2006. In 2006, an increase in short-term debt was the principal source of cash flows from financing activities. Cash from financing activities was used to retire long-term debt and to pay dividends.

In 2005, we received cash primarily from the issuance of long-term debt and we used cash primarily to retire long-term debt and pay dividends.

Financing activities in 2005 used $127.9 million of cash compared to $323.2 million in 2004. 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.

Future Cash Requirements

Our business requires significant capital investments. Through 2009, we expect we will need cash mostly for utility construction programs designed to improve facilities providing electric service, for future peaking capacity needs, for construction of new transmission lines and to comply with environmental regulations. We expect to meet these cash needs with internally generated cash flow, borrowings under Westar Energy's revolving credit facility and through the issuance of securities in the capital markets.

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. We expect that costs related to updating or installing emissions controls will be material. As discussed above, the ECRR will allow for timely inclusion in rates of the costs of capital expenditures directly tied to environmental improvements required by the Clean Air Act. We believe that other costs incurred would qualify for recovery through rates.

Capital expenditures for 2006 and anticipated capital expenditures for 2007 through 2009, including costs of removal, are shown in the following table.

	Actual 2006	2007	2008	2009
		(In Thousands)		
Generation:				
Replacements and other	$ 51,343	$ 93,005	$ 133,534	$ 145,199
Additional capacity	74,552	213,537	116,843	33,652
Environmental	47,103	191,987	168,268	128,428
Nuclear fuel	25,716	31,517	19,420	19,901
Transmission	31,537	65,310	104,656	137,366
Distribution:				
Replacements and other	38,409	37,106	56,742	73,794
New customers	64,161	56,175	57,467	58,788
Other	12,039	47,643	18,597	16,633
Total capital expenditures	$ 344,860	$ 736,280	$ 675,527	$ 613,761

We prepare these estimates for planning purposes and revise our estimates from time to time. Actual expenditures will differ from our estimates. These amounts do not include any estimate of expenditures that may be incurred as a result of the EPA investigation.

Maturities of long-term debt as of December 31, 2006 are as follows.

Year	Principal Amount
	(In Thousands)
2007	$ —
2008	—
2009	145,078
2010	—
Thereafter	1,421,268
Total long-term debt maturities	$ 1,566,346

Debt Financings

On June 1, 2006, we refinanced $100.0 million of pollution control bonds, which were to mature in 2031. We replaced this issue with two new pollution control bond series of $50.0 million each. One series carries an interest rate of 4.85% and matures in 2031. The second series carries a variable interest rate and also matures in 2031.

On March 17, 2006, Westar Energy amended and restated the revolving credit facility dated May 6, 2005 to increase the size of the facility, extend the term and reduce borrowing costs. The amended and restated revolving credit facility matures on March 17, 2011. So long as there is no default or event of default under the revolving credit facility, we may elect annually prior to the anniversary date of the facility to extend the term of the credit facility for one year. This one year extension can be requested twice during the term of the facility, subject to lender participation. The facility allows Westar Energy to borrow up to an aggregate amount of $500.0 million, including letters of credit up to a maximum aggregate amount of $150.0 million. We may elect, subject to FERC approval, to increase the aggregate amount of borrowings under the facility to $750.0 million by increasing the commitment of one or more lenders who have agreed to such increase, or by adding one or more new lenders with the consent of the Administrative Agent and any letter of credit issuing bank, which will not be unreasonably withheld, so long as there is no default or event of default under the revolving credit facility.

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

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

On June 30, 2005, Westar Energy sold $400.0 million aggregate principal amount of Westar Energy first mortgage bonds, consisting of $150.0 million of 5.875% bonds maturing in 2036 and $250.0 million of 5.1% bonds maturing in 2020. On July 27, 2005, proceeds from the offering were used to redeem the outstanding $365.0 million aggregate principal amount of Westar Energy's 7.875% first mortgage bonds due 2007, together with accrued interest and a call premium equal to approximately 6% of the principal outstanding, and for general corporate purposes. The call premium is recorded as a regulatory asset and is being amortized over the term of the new 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. The call premium is recorded as a regulatory asset and is being amortized over the term of the new bonds.

Debt Covenants

Some of our debt instruments contain restrictions that require us to maintain 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 as of December 31, 2006.

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.

In February 2007, S&P upgraded its credit ratings for our securities as shown in the table below. In May 2006, Moody's Investors Service upgraded its credit ratings for our securities as shown in the table below and changed its outlook for our ratings to stable. In March 2006, Fitch Investors Service upgraded its credit ratings for our securities as shown in the table below and changed its outlook for our ratings to stable.

As of February 26, 2007, 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	Baa2	Baa3	Baa2
Fitch	BBB	BBB-	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 the Westar Energy revolving credit agreement 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

As of December 31, 2006 and 2005, our long-term capital structure was as follows:

	2006	2005
Common equity	49%	45%
Preferred stock	1%	1%
Long-term debt	50%	54%
Total	100%	100%

OFF-BALANCE SHEET ARRANGEMENTS

As of December 31, 2006, we did not have any off-balance sheet financing arrangements, other than our operating leases entered into in the ordinary course of business. For additional information on our operating leases, see Note 21 of the Notes to Consolidated Financial Statements, "Leases."

CONTRACTUAL OBLIGATIONS AND COMMERCIAL COMMITMENTS

In the course of our business activities, we enter into a variety of obligations and commercial commitments. Some of these result in direct obligations reflected on our consolidated balance sheets while others are commitments, some firm and some based on uncertainties, not reflected in our underlying consolidated financial statements. The obligations listed below include amounts for on-going needs for which contractual obligations existed as of December 31, 2006.

Contractual Cash Obligations

The following table summarizes the projected future cash payments for our contractual obligations existing as of December 31, 2006.

	Total	2007	2008-2009	2010-2011	Thereafter
			(In Thousands)		
Long-term debt[a]	$1,566,346	$ —	$145,078	$ —	$1,421,268
Interest on long-term debt[b]	1,461,210	83,973	167,946	147,272	1,062,019
Adjusted long-term debt	3,027,556	83,973	313,024	147,272	2,483,287
Wolf Creek pension benefit funding obligations[c]	6,300	6,300	—	—	—
Capital leases[d]	21,779	6,162	8,210	4,845	2,562
Operating leases[e]	583,739	35,272	89,064	84,988	374,415
Fossil fuel[f]	1,413,183	218,296	379,957	274,746	540,184
Nuclear fuel[g]	347,493	35,360	37,860	45,205	229,068
Unconditional purchase obligations	176,120	56,441	113,544	6,135	—
Total contractual obligations, including adjusted long-term debt	$5,576,170	$441,804	$941,659	$563,191	$3,629,516

[a] *See Note 10 of the Notes to Consolidated Financial Statements, "Long-Term Debt," for individual long-term debt maturities.*

[b] *We calculate interest on our variable rate debt based on the effective interest rate as of December 31, 2006*

[c] *Pension benefit funding obligations represent only the minimum funding requirements under the Employee Retirement Income Securities Act of 1974. Minimum funding requirements for future periods are not yet known. Our funding policy is to contribute amounts sufficient to meet the minimum funding requirements plus additional amounts as deemed fiscally appropriate; therefore, actual contributions may differ from expected contributions. See Notes 12 and 13 of the Notes to Consolidated Financial Statements, "Employee Benefit Plans" and "Wolf Creek Employee Benefit Plans," for additional information regarding pensions.*

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

[e] *Includes the La Cygne unit 2 lease, office space, operating facilities, office equipment, operating equipment, rail car leases and other miscellaneous commitments.*

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

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

Commercial Commitments

Our commercial commitments existing as of December 31, 2006 consist of outstanding letters of credit that expire in 2007, some of which automatically renew annually. The letters of credit are comprised of $26.2 million related to our energy marketing and trading activities, $3.4 million related to worker's compensation and $2.7 million related to other operating activities for a total outstanding balance of $32.3 million.

OTHER INFORMATION

Stock Based Compensation

Effective January 1, 2006, we adopted SFAS No. 123R using the modified prospective transition method. Since 2002, we have used RSUs exclusively for our stock-based compensation awards. Given the characteristics of our stock-based compensation awards, the adoption of SFAS No. 123R did not have a material impact on our consolidated results of operations.

Total unrecognized compensation cost related to RSU awards was $4.4 million as of December 31, 2006. We expect to recognize these costs over a remaining weighted-average period of 3.7 years. Upon adoption of SFAS No. 123R, we were required to charge $10.3 million of unearned stock compensation against additional paid-in capital. There were no modifications of awards during the years ended December 31, 2006, 2005 or 2004.

Prior to the adoption of SFAS No. 123R, we reported all tax benefits resulting from the vesting of RSU awards and exercise of stock options as operating cash flows in the consolidated statements of cash flows. SFAS No. 123R requires cash retained as a result of excess tax benefits resulting from the tax deductions in excess of the related compensation cost recognized in the financial statements to be classified as cash flows from financing activities in the consolidated statements of cash flows.

Pension Obligation

We made a $20.8 million voluntary pension contribution to the Westar Energy pension trust in 2006. Based on the January 1, 2006 funding valuation, we are not required to make any contributions to the pension trust during 2007. We currently expect to make a voluntary contribution to the pension trust of an estimated $11.8 million in 2007. We may make additional contributions into the pension trust in 2007 depending on how the funded status of the pension plan changes, regulatory treatment for the contributions and conclusions reached as there is more clarity with respect to the Pension Protection Act of 2006 (PPA) that was signed into law on August 17, 2006. The United States Treasury Department is in the process of developing implementation guidance for the PPA; however, it is likely the PPA will accelerate minimum funding requirements beginning in 2009. We may choose to pre-fund some of the anticipated required funding.

Customer Rebates

We made rebates to customers of $10.0 million in 2006 and $10.5 million during the year ended December 31, 2005, in accordance with a July 25, 2003 KCC Order.

Purchase of Electric Generation Facility

On October 31, 2006, we purchased a 300 MW electric generation facility and related assets from OESC for $53.0 million. As part of this transaction, we entered into an agreement to provide OESC with 75 MW of capacity through 2015.

Agreement to Assume Leasehold Interest in Jeffrey Energy Center

On August 30, 2006, we entered into an agreement with Aquila, Inc. to assume its 8% leasehold interest in Jeffrey Energy Center. We expect this transaction to close in 2007. In relation to this transaction, we entered into a long-term sale agreement with Mid-Kansas Electric Company, LLC (MKEC) pursuant to which we will provide MKEC with the capacity and energy from the 8% leasehold interest in the Jeffrey Energy Center through January 3, 2019. We also agreed to purchase Aquila's materials and supplies, inventory and leasehold improvements at the then unamortized book balance as of the date of closing. We estimate this amount will be approximately $30.0 million. Following the closing of this transaction, our capital expenditures associated with Jeffrey Energy Center will reflect not only the 84% of the station that we own, but also the 8% leasehold interest we assumed from Aquila, Inc.

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.

As of December 31, 2006, we had recorded regulatory assets currently subject to recovery in future rates of approximately $609.5 million and regulatory liabilities of $133.5 million as discussed in greater detail in Note 2 of the Notes to Consolidated Financial Statements, "Summary of Significant Accounting Policies — Regulatory Accounting." We believe that it is probable that our regulatory assets will be recovered in the future.

Asset Retirement Obligations

Legal Liability

In accordance with SFAS No. 143 and FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations" (FIN 47), we have recognized legal obligations associated with the disposal of long-lived assets that result from the acquisition, construction, development or normal operation of such assets. Concurrent with the recognition of the liability, the estimated cost of an asset retirement obligation is capitalized and depreciated over the remaining life of the asset.

We have recorded asset retirement obligations at fair value for the estimated cost to: decommission Wolf Creek (our 47% share); disposal of asbestos insulating material at our power plants; remediation of ash disposal ponds; and the disposal of polychlorinated biphenyl (PCB) contaminated oil.

As of December 31, 2006 and 2005, we have recorded asset retirement obligations of $84.2 million and $129.9 million, respectively. For additional information on our legal asset retirement obligations, see Note 15 of the Notes to Consolidated Financial Statements, "Asset Retirement Obligations."

Non-Legal Liability — Cost of Removal

We recover in rates, as a component of depreciation, the costs to dispose of utility plant assets that do not represent legal retirement obligations. As of December 31, 2006 and 2005, we had $13.4 million and $6.9 million, respectively, in amounts collected, but unspent, for removal costs classified as a regulatory liability. The net amount related to non-legal retirement costs can fluctuate based on amounts recovered in rates compared to removal costs incurred.

Guardian International Preferred Stock

On March 6, 2006, Guardian was acquired by Devcon International Corporation in a merger. In connection with this merger, we received approximately $23.2 million for 15,214 shares of Guardian Series D preferred stock and 8,000 shares of Guardian Series E preferred stock held of record by us. We beneficially owned 354.4 shares of the Guardian Series D preferred stock and 312.9 shares of the Guardian Series E preferred stock. We recognized a gain of approximately $0.3 million as a result of this transaction. Certain current and former officers beneficially owned the remaining shares. Of these shares, 14,094 shares of Guardian Series D preferred stock and 7,276 shares of Guardian Series E preferred stock were beneficially owned by Mr. Wittig and Mr. Lake. The ownership of the shares beneficially owned by either Mr. Wittig or Mr. Lake, as well as related dividends, and now the cash received for the shares, is disputed and is the subject of the arbitration proceeding with Mr. Wittig and Mr. Lake discussed in Note 16, "Legal Proceedings." These shares were, and now the cash received for the shares are, also part of the property forfeited by Mr. Wittig and Mr. Lake in the criminal proceeding discussed in Note 18, "Potential Liabilities to David C. Wittig and Douglas T. Lake." As a result of this transaction, we no longer hold any Guardian securities.

New Accounting Pronouncements

SFAS No. 159 — The Fair Value Option for Financial Assets and Financial Liabilities

In February 2007, the Financial Accounting Standards Board (FASB) released SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities — Including an amendment to FASB Statement No. 115." SFAS No. 159 permits entities to choose to measure many financial instruments and certain other items at fair value. A business entity shall report unrealized gains and losses on items for which fair value option has been elected in earnings at each subsequent reporting date. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. We anticipate adopting the guidance effective January 1, 2008. We are currently evaluating what impact the adoption of SFAS No. 159 will have on our consolidated financial statements.

SFAS No. 157 — Fair Value Measurements

In September 2006, FASB released SFAS No. 157, "Fair Value Measurements." SFAS No. 157 defines fair value, establishes a framework for measuring fair value in GAAP, and expands disclosures about fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007 with the cumulative effect of the change in accounting principle recorded as an adjustment to opening retained earnings. We anticipate adopting the guidance effective January 1, 2008. We are currently evaluating what impact the adoption of SFAS No. 157 will have on our consolidated financial statements.

FIN 48 — Accounting for Uncertainty in Income Taxes

In July 2006, FASB released FASB Interpretation No. (FIN) 48, "Accounting for Uncertainty in Income Taxes — an Interpretation of FASB Statement No. 109." FIN 48 prescribes a comprehensive model for how companies should recognize, measure and disclose in their financial statements uncertain tax positions taken, or expected to be taken, on a tax return. It also provides guidance on derecognizing, classification, interest and penalties, accounting in interim periods, disclosure, and transition. FIN 48 is effective for fiscal years beginning after December 15, 2006 with the cumulative effect of the change in accounting principle recorded as an adjustment to opening retained earnings.

We will adopt the guidance effective January 1, 2007. As of this date, we continue to evaluate what impact the adoption of FIN 48 will have on our consolidated financial statements. We do not expect the adoption of FIN 48 to have a material impact on our consolidated financial statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Hedging Activity

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

In an effort to mitigate market risk associated with fuel and energy prices, we may use economic hedging arrangements to reduce our exposure to price changes. Our future exposure to changes in prices will be dependent on the market prices and the extent and effectiveness of any economic hedging arrangements into which we enter.

Market Price Risks

Our economic hedging and trading activities involve risks, including commodity price risk, interest rate risk and credit risk. Commodity price risk is the risk that changes in commodity prices may impact the price at which we are able to buy and sell electricity and purchase fuels for our generating units. We believe we will continue to experience volatility in the prices for these commodities.

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

Credit risk represents the risk of loss resulting from non-performance by a counterparty of its contractual obligations. We have exposure to credit risk and counterparty default risk with our retail, wholesale and energy marketing activities. We maintain credit policies intended to reduce overall credit risk. We employ additional credit risk control mechanisms that we believe are appropriate, such as letters of credit, parental guarantees and master netting agreements with counterparties that allow for offsetting exposures. Results actually achieved from economic hedging and trading activities could vary materially from intended results and could materially affect our consolidated financial results depending on the success of our credit risk management efforts.

Commodity Price Exposure

We may engage in both financial and physical trading to manage our commodity price risk. We trade electricity, coal, natural gas and oil. We use a variety of financial instruments, including forward contracts, options and swaps, and we trade energy commodity contracts. We may also use economic hedging techniques to manage overall fuel expenditures. We procure physical products 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. Our risk of loss, in the form of increased costs, from market price changes in fuel is mitigated through the RECA, which provides for inclusion of most fuel costs in retail rates.

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 2007.

The use of the VaR method requires assumptions, including the selection of a confidence level for potential losses and the estimated holding period. 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 calculation has been adjusted to remove the impact of fuel contracts due to implementation of the RECA in 2006. The VaR amounts for 2006 and 2005 were as follows.

	2006	2005
	(In Thousands)	
High	$2,178	$2,690
Low	449	471
Average	1,089	1,398

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 possibility of a 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 loss of revenues associated with this could be material and adverse to our consolidated results of operations and financial condition.

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

Interest Rate Exposure

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

We had approximately $431.9 million of variable rate debt as of December 31, 2006. A 100 basis point change in interest rates applicable to this debt would impact income before income taxes on an annualized basis by approximately $4.3 million. In addition, a decline in interest rates generally can serve to increase our pension and post retirement obligations and affect investment returns.

Security Price Risk

We maintain trust funds, as required by the NRC and Kansas state laws, to fund certain costs of nuclear plant decommissioning. As of December 31, 2006, these funds were comprised of 63% equity securities, 33% debt securities and 4% cash and cash equivalents. The fair value of these funds was $111.1 million as of December 31, 2006 and $100.8 million as of December 31, 2005. By maintaining a diversified portfolio of securities, we seek to maximize the returns to fund the decommissioning obligation within acceptable risk tolerances. However, debt and equity securities in the portfolio are exposed to price fluctuations in the capital markets. If the value of the securities diminishes, the cost of funding the obligation rises. We actively monitor the portfolio by benchmarking the performance of the investments against relevant indices and by maintaining and periodically reviewing the asset allocation in relation to established policy targets. Our exposure to equity price market risk is, in part, mitigated because we are currently allowed to recover decommissioning costs in the rates we charge our customers.

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 as of December 31, 2006. 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, as of December 31, 2006, 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 Control over Financial Reporting, that Westar Energy, Inc. and its subsidiaries (the "Company") maintained effective internal control over financial reporting as of December 31, 2006, 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 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.

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2006, 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, 2006, 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, 2006 of the Company and our report dated February 28, 2007 expressed an unqualified opinion on those financial statements and financial statement schedule and included an explanatory paragraph regarding the Company's adoption of new accounting standards.

/s/ Deloitte & Touche LLP

Kansas City, Missouri
February 28, 2007

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, 2006 and 2005, and the related consolidated statements of income, comprehensive income, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2006. 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 these 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 Westar Energy, Inc. and subsidiaries as of December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, 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 12 to the financial statements, in 2006, the Company adopted Statement of Financial Accounting Standard No. 123(R), "Share-Based Payment," and Statement of Financial Accounting Standard No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans."

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, 2006, 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 February 28, 2007 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
February 28, 2007

WESTAR ENERGY, INC. CONSOLIDATED BALANCE SHEETS

As of December 31, (Dollars in Thousands)	2006	2005
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	**$ 18,196**	$ 38,539
Restricted cash	**—**	2,430
Accounts receivable, net	**179,859**	124,711
Inventories and supplies, net	**147,930**	101,818
Energy marketing contracts	**67,267**	55,948
Tax receivable	**15,142**	1,565
Deferred tax assets	**853**	19,211
Prepaid expenses	**29,620**	30,452
Regulatory assets	**58,777**	39,300
Other	**19,076**	61,646
Total Current Assets	**536,720**	475,620
PROPERTY, PLANT AND EQUIPMENT, NET	**4,071,607**	3,947,732
OTHER ASSETS:		
Restricted cash	**—**	25,014
Regulatory assets	**550,703**	398,198
Nuclear decommissioning trust	**111,135**	100,803
Energy marketing contracts	**11,173**	75,698
Other	**173,837**	187,004
Total Other Assets	**846,848**	786,717
TOTAL ASSETS	**$5,455,175**	$ 5,210,069
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Current maturities of long-term debt	**$ —**	$ 100,000
Short-term debt	**160,000**	—
Accounts payable	**150,424**	109,807
Accrued taxes	**102,219**	100,568
Energy marketing contracts	**57,281**	11,710
Accrued interest	**32,928**	36,609
Regulatory liabilities	**49,836**	50,970
Other	**110,488**	140,403
Total Current Liabilities	**663,176**	550,067
LONG-TERM LIABILITIES:		
Long-term debt, net	**1,563,265**	1,562,990
Deferred income taxes	**906,311**	911,135
Unamortized investment tax credits	**61,668**	65,558
Deferred gain from sale-leaseback	**125,017**	130,513
Accrued employee benefits	**246,930**	158,418
Asset retirement obligations	**84,192**	129,888
Energy marketing contracts	**534**	2,007
Regulatory liabilities	**83,664**	111,523
Other	**152,852**	150,531
Total Long-Term Liabilities	**3,224,433**	3,222,563
COMMITMENTS AND CONTINGENCIES (see Notes 14 and 16)		
TEMPORARY EQUITY (See Note 12)	**6,671**	—
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 87,394,886 shares and 86,835,371 shares, respectively	**436,974**	434,177
Paid-in capital	**916,605**	923,083
Unearned compensation	**—**	(10,257)
Retained earnings	**185,779**	109,987
Accumulated other comprehensive income (loss), net	**101**	(40,987)
Total Shareholders' Equity	**1,560,895**	1,437,439
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**$5,455,175**	$ 5,210,069

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

WESTAR ENERGY, INC. CONSOLIDATED STATEMENTS OF INCOME

Year Ended December 31,	2006	2005	2004
(Dollars in Thousands, Except Per Share Amounts)			
SALES	**$1,605,743**	$ 1,583,278	$ 1,464,489
OPERATING EXPENSES:			
Fuel and purchased power	**483,959**	528,229	419,788
Operating and maintenance	**463,785**	437,741	412,002
Depreciation and amortization	**180,228**	150,520	169,310
Selling, general and administrative	**171,001**	166,060	173,498
Total Operating Expenses	**1,298,973**	1,282,550	1,174,598
INCOME FROM OPERATIONS	**306,770**	300,728	289,891
OTHER INCOME (EXPENSE):			
Investment earnings	**9,212**	11,365	16,746
Loss on extinguishment of debt	**—**	—	(18,840)
Other income	**18,000**	9,948	2,756
Other expense	**(13,711)**	(17,580)	(14,879)
Total Other Income (Expense)	**13,501**	3,733	(14,217)
Interest expense	**98,650**	109,080	142,151
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	**221,621**	195,381	133,523
Income tax expense	**56,312**	60,513	33,443
INCOME FROM CONTINUING OPERATIONS	**165,309**	134,868	100,080
Results of discontinued operations, net of tax	**—**	742	78,790
NET INCOME	**165,309**	135,610	178,870
Preferred dividends	**970**	970	970
EARNINGS AVAILABLE FOR COMMON STOCK	**$ 164,339**	$ 134,640	$ 177,900
BASIC AND DILUTED EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING (see Note 2):			
Basic earnings available from continuing operations	**$ 1.88**	$ 1.54	$ 1.19
Discontinued operations, net of tax	**—**	0.01	0.95
Basic earnings available	**$ 1.88**	$ 1.55	$ 2.14
Diluted earnings available from continuing operations	**$ 1.87**	$ 1.53	$ 1.19
Discontinued operations, net of tax	**—**	0.01	0.94
Diluted earnings available	**$ 1.87**	$ 1.54	$ 2.13
Average equivalent common shares outstanding	**87,509,800**	86,855,485	82,941,374
DIVIDENDS DECLARED PER COMMON SHARE	**$ 1.00**	$ 0.92	$ 0.80

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

WESTAR ENERGY, INC. CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year Ended December 31, (Dollars in Thousands)	**2006**	2005	2004
NET INCOME	**$ 165,309**	$ 135,610	$ 178,870
OTHER COMPREHENSIVE INCOME (LOSS):			
Unrealized holding (loss) gain on marketable securities arising during the period	**(57)**	45	11
Minimum pension liability adjustment	**31,841**	(68,321)	7,769
Other comprehensive income (loss), before tax	**31,784**	(68,276)	7,780
Income tax (expense) benefit related to items of other comprehensive income	**(12,666)**	27,176	(3,090)
Other comprehensive income (loss), net of tax	**19,118**	(41,100)	4,690
COMPREHENSIVE INCOME	**$ 184,427**	$ 94,510	$ 183,560

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

WESTAR ENERGY, INC. CONSOLIDATED STATEMENTS OF CASH FLOWS

Year Ended December 31, (Dollars in Thousands)	2006	2005	2004
CASH FLOWS FROM (USED IN) OPERATING ACTIVITIES:			
Net income	**$ 165,309**	$ 135,610	$ 178,870
Adjustments to reconcile net income to net cash provided by operating activities:			
Discontinued operations, net of tax	**—**	(742)	(78,790)
Depreciation and amortization	**180,228**	150,520	169,310
Amortization of nuclear fuel	**13,851**	13,315	14,221
Amortization of deferred gain from sale-leaseback	**(5,495)**	(8,469)	(11,828)
Amortization of corporate-owned life insurance	**15,336**	16,265	12,622
Non-cash stock compensation	**3,389**	3,219	7,916
Net changes in energy marketing assets and liabilities	**(7,505)**	5,799	4,383
Loss on extinguishment of debt	**—**	—	18,840
Accrued liability to certain former officers	**3,813**	2,018	8,384
Gain on sale of utility plant and property	**(570)**	—	(503)
Net deferred income taxes and credits	**(4,203)**	25,552	(5,215)
Stock based compensation excess tax benefits	**(854)**	—	—
Changes in working capital items, net of acquisitions and dispositions:			
Accounts receivable, net	**(55,148)**	(32,179)	(11,561)
Inventories and supplies	**(46,112)**	22,745	10,368
Prepaid expenses and other	**(4,095)**	(65,635)	(35,114)
Accounts payable	**22,625**	6,929	6,439
Accrued taxes	**(13,160)**	91,938	43,463
Other current liabilities	**(5,708)**	(20,876)	(5,907)
Changes in other assets	**19,412**	20,374	12,846
Changes in other liabilities	**(25,127)**	(12,492)	6,880
Cash flows from operating activities	**255,986**	353,891	345,624
CASH FLOWS FROM (USED IN) INVESTING ACTIVITIES:			
Additions to property, plant and equipment	**(344,860)**	(212,814)	(197,149)
Purchase of securities within the nuclear decommissioning trust fund	**(345,541)**	(372,426)	(313,241)
Sale of securities within the nuclear decommissioning trust fund	**341,410**	367,570	309,105
Investment in corporate-owned life insurance	**(19,127)**	(19,346)	(19,658)
Proceeds from investment in corporate-owned life insurance	**22,684**	10,997	—
Proceeds from sale of Protection One, Inc.	**—**	—	81,670
Proceeds from sale of Protection One, Inc. bonds	**—**	—	26,640
Proceeds from sale of plant and property	**1,695**	—	8,604
Proceeds from sale of international investment	**—**	—	11,219
Issuance of officer loans and interest, net of payments	**—**	—	2
Proceeds from other investments	**53,411**	13,990	16,548
Cash flows used in investing activities	**(290,328)**	(212,029)	(76,260)
CASH FLOWS FROM (USED IN) FINANCING ACTIVITIES:			
Short-term debt, net	**160,000**	—	(1,000)
Proceeds from long-term debt	**99,662**	642,807	623,301
Retirements of long-term debt	**(200,000)**	(741,847)	(1,188,081)
Funds in trust for debt repayments	**—**	—	78
Repayment of capital leases	**(4,813)**	(4,898)	(4,977)
Borrowings against cash surrender value of corporate-owned life insurance	**59,697**	58,039	57,090
Repayment of borrowings against cash surrender value of corporate-owned life insurance	**(24,133)**	(13,026)	(444)
Stock based compensation excess tax benefits	**854**	—	—
Issuance of common stock, net	**2,394**	5,584	245,130
Cash dividends paid	**(80,894)**	(74,593)	(56,189)
Reissuance of treasury stock	**—**	—	1,927
Cash flows from (used in) financing activities	**12,767**	(127,934)	(323,165)
CASH FLOWS FROM (USED IN) DISCONTINUED OPERATIONS:			
Cash flows from operating activities	**—**	—	2,265
Cash flows from (used in) investing activities	**1,232**	—	(3,412)
Net cash from (used in) discontinued operations	**1,232**	—	(1,147)
NET (DECREASE) INCREASE IN CASH AND CASH EQUIVALENTS	**(20,343)**	13,928	(54,948)
CASH AND CASH EQUIVALENTS:			
Beginning of period	**38,539**	24,611	79,559
End of period	**$ 18,196**	$ 38,539	$ 24,611

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

WESTAR ENERGY, INC. CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

	Cumulative Preferred Stock	Common Stock	Paid-in Capital	Unearned Compensation	Loans to Officers	Retained Earnings (Accumulated Deficit)	Treasury Stock	Accumulated Other Comprehensive (Loss) Income	Total Shareholders' Equity
				(Dollars in Thousands)					
BALANCE AT DECEMBER 31, 2003	$ 21,436	$364,201	$776,754	$ (15,879)	$ (2)	$(102,782)	$ (2,391)	$ (4,577)	$1,036,760
Net income	—	—	—	—	—	178,870	—	—	178,870
Issuance of common stock, net	—	65,948	192,337	—	—	—	—	—	258,285
Preferred dividends, net of retirements	—	—	653	—	—	(1,074)	—	—	(421)
Dividends on common stock	—	—	(46,473)	—	—	(19,786)	—	—	(66,259)
Issuance of treasury stock	—	—	1,230	—	—	(175)	2,391	—	3,446
Grant of restricted stock	—	—	1,417	(1,417)	—	—	—	—	—
Amortization of restricted stock	—	—	—	6,838	—	—	—	—	6,838
Forfeited restricted stock	—	—	—	97	—	—	—	—	97
Stock compensation	—	—	(12,986)	—	—	—	—	—	(12,986)
Issuance of officer loans and interest, net of payments	—	—	—	—	2	—	—	—	2
Unrealized gain on marketable securities	—	—	—	—	—	—	—	11	11
Minimum pension liability adjustment	—	—	—	—	—	—	—	7,769	7,769
Income tax expense	—	—	—	—	—	—	—	(3,090)	(3,090)
BALANCE AT DECEMBER 31, 2004	21,436	430,149	912,932	(10,361)	—	55,053	—	113	1,409,322
Net income	—	—	—	—	—	135,610	—	—	135,610
Issuance of common stock, net	—	4,028	13,171	—	—	—	—	—	17,199
Preferred dividends, net of retirements	—	—	—	—	—	(970)	—	—	(970)
Dividends on common stock	—	—	—	—	—	(79,706)	—	—	(79,706)
Grant of restricted stock	—	—	2,986	(2,986)	—	—	—	—	—
Amortization of restricted stock	—	—	—	3,019	—	—	—	—	3,019
Forfeited restricted stock	—	—	—	71	—	—	—	—	71
Stock compensation and tax benefit	—	—	(6,006)	—	—	—	—	—	(6,006)
Unrealized gain on marketable securities	—	—	—	—	—	—	—	45	45
Minimum pension liability adjustment	—	—	—	—	—	—	—	(68,321)	(68,321)
Income tax benefit	—	—	—	—	—	—	—	27,176	27,176
BALANCE AT DECEMBER 31, 2005	**21,436**	**434,177**	**923,083**	**(10,257)**	**—**	**109,987**	**—**	**(40,987)**	**1,437,439**
Net income	—	—	—	—	—	**165,309**	—	—	**165,309**
Issuance of common stock, net	—	**2,797**	**9,585**	—	—	—	—	—	**12,382**
Preferred dividends, net of retirements	—	—	—	—	—	**(970)**	—	—	**(970)**
Dividends on common stock	—	—	—	—	—	**(88,547)**	—	—	**(88,547)**
Reclass to Temporary Equity	—	—	**(6,671)**	—	—	—	—	—	**(6,671)**
Reclass of unearned compensation	—	—	**(10,257)**	**10,257**	—	—	—	—	—
Amortization of restricted stock	—	—	**2,956**	—	—	—	—	—	**2,956**
Stock compensation and tax benefit	—	—	**(2,091)**	—	—	—	—	—	**(2,091)**
Unrealized loss on marketable securities	—	—	—	—	—	—	—	**(57)**	**(57)**
Minimum pension liability adjustment	—	—	—	—	—	—	—	**31,841**	**31,841**
Income tax expense	—	—	—	—	—	—	—	**(12,666)**	**(12,666)**
Reclass to regulatory asset	—	—	—	—	—	—	—	**21,970**	**21,970**
BALANCE AT DECEMBER 31, 2006	**$ 21,436**	**$436,974**	**$916,605**	**$ —**	**$ —**	**$ 185,779**	**$ —**	**$ 101**	**$1,560,895**

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 669,000 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. KGE owns a 47% interest in the Wolf Creek Generating Station (Wolf Creek), a nuclear power plant located near Burlington, 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.

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

Use of Management's Estimates

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

Regulatory Accounting

We apply accounting standards for our regulated utility operations that recognize the economic effects of rate regulation in accordance with 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 future reductions in revenue or refunds to customers through the rate making process. Regulatory assets and liabilities reflected on our consolidated balance sheets are as follows.

As of December 31,	2006	2005
	(In Thousands)	
Regulatory Assets:		
Amounts due from customers for future income taxes, net	$160,147	$166,632
Debt reacquisition costs	97,342	103,563
Deferred employee benefit costs	189,226	4,160
Disallowed plant costs	16,733	16,929
2002 ice storm costs	14,897	19,389
2005 ice storm costs	24,540	30,878
Asset retirement obligations	19,312	18,686
Depreciation	58,863	49,894
Property taxes	181	10,462
Wolf Creek outage	14,975	9,915
Retail energy cost adjustment	6,950	—
Other regulatory assets	6,314	6,990
Total regulatory assets	$609,480	$437,498
Regulatory Liabilities:		
Fuel supply contracts	$ 12,794	$117,668
Nuclear decommissioning	48,793	16,048
Retail energy cost adjustment	19,884	—
State Line purchased power	6,623	8,109
Terminal net salvage	16,439	—
Removal costs	13,355	6,888
Other regulatory liabilities	15,612	13,780
Total regulatory liabilities	$133,500	$162,493

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

- **Amounts due from customers for future income taxes, net:** In accordance with various rate orders, we have reduced rates to reflect the tax benefits associated with certain tax deductions, thereby passing on these benefits to customers at the time we receive them. 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 in future periods. We have recorded a regulatory asset for these amounts. We also have recorded a regulatory liability for our obligation to customers for taxes recovered from customers in earlier periods when corporate tax rates were higher than the current tax rates.

The benefit will be returned to customers as these temporary differences reverse in future periods. 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.

- **Debt reacquisition costs:** This includes costs incurred to reacquire and refinance debt. Debt reacquisition costs are amortized over the term of the new debt.
- **Deferred employee benefit costs:** Employee benefit costs include $189.4 million, less $3.1 million for applicable taxes, for pension and post-retirement benefit obligations pursuant to SFAS No. 158 and $2.9 million for post-retirement expenses in excess of amounts paid. We will amortize to expense approximately $17.6 million during 2007 for the benefit obligation. The post-retirement expenses are recovered over a period of five years.
- **Disallowed plant costs:** In 1985, the Kansas Corporation Commission (KCC) disallowed certain costs associated with the original construction of Wolf Creek. In 1987, the KCC authorized KGE to recover these costs in rates over the useful life of Wolf Creek.
- **2002 ice storm costs:** We accumulated and deferred for later recovery costs related to restoring our electric distribution system from the damage it suffered as a result of an ice storm that occurred in January 2002. The KCC authorized us to accrue carrying costs on this item. As allowed by the December 28, 2005 KCC Order, in 2006 Westar Energy began recovering $7.7 million over a three year period and KGE began recovering $11.7 million over a five year period. We earn a return on this asset.
- **2005 ice storm costs:** We accumulated and deferred for future recovery costs related to restoring our electric distribution system from the damage it sustained as a result of a subsequent, more severe, ice storm that occurred in January 2005. The KCC authorized us to accrue carrying costs on this item. As allowed by the December 28, 2005 KCC Order, in 2006 Westar Energy began recovering $5.6 million over a three year period and KGE began recovering $25.3 million over a five year period. We earn a return on this asset.
- **Asset retirement obligations:** This represents amounts associated with our asset retirement obligations as discussed in Note 15, "Asset Retirement Obligations." We recover this item over the life of the utility plant.
- **Depreciation:** This represents the difference between the regulatory depreciation expense and the depreciation expense we record for financial reporting purposes. We earn a return on this asset. We recover this item over the life of the related utility plant.
- **Property taxes:** We are allowed to adjust our rates to recover an amount equal to the property taxes we must pay. This item represents the amount we have paid for property taxes that we have not yet collected from customers. We expect to recover this shortfall over a one year period.
- **Wolf Creek outage:** Wolf Creek incurs a refueling and maintenance outage approximately every 18 months. The expenses associated with these maintenance and refueling outages are deferred and amortized over the period of time between such planned outages.
- **Retail energy cost adjustment:** We are allowed to adjust our retail prices to reflect changes in the cost of fuel and purchased power needed to serve our customers. This item represents the difference in the actual cost of fuel consumed in producing electricity and the cost of purchased power and amounts we have collected from customers. We expect to recover in our rates this shortfall over a one year period.
- **Other regulatory assets:** This item includes various regulatory assets that individually are small in relation to the total regulatory asset balance. Other regulatory assets have various recovery periods, most of which range from three to five years.

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

- **Fuel supply contracts:** We use mark to market accounting for some of our fuel contracts. This item represents the non-cash net gain position on fuel supply contracts that are marked-to-market in accordance with the requirements of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." Under the RECA, fuel contract market gains accrue to the benefit of our customers.
- **Nuclear decommissioning:** We have a legal obligation to decommission Wolf Creek at the end of its useful life. This amount represents the difference between the fair value of our asset retirement obligation and the fair value of the assets in our decommissioning trust. See Note 6, "Financial Investments and Trading Securities" and Note 15, "Asset Retirement Obligations," for information regarding our Nuclear Decommissioning Trust Fund and our asset retirement obligation.
- **Retail energy cost adjustment:** We are allowed to adjust our retail prices to reflect changes in the cost of fuel and purchased power needed to serve our customers. We bill customers based on our estimated costs. This item represents the amount we collected from customers that was in excess of our actual cost of fuel and purchased power. We will refund to customers this excess recovery over a one year period.
- **State Line purchased power:** This represents amounts received from customers in excess of costs incurred under Westar Energy's purchased power agreement with Westar Generating, Inc., a wholly owned subsidiary.
- **Terminal net salvage:** This represents amounts collected in rates for terminal net salvage. Pursuant to the February 8, 2007 KCC Order, the KCC ordered us to refund amounts previously collected. We expect to refund this amount during 2007.
- **Removal costs:** This represents amounts collected, but unspent, for costs to dispose of utility plant assets that do not represent legal retirement obligations. The liability will be discharged as removal costs are incurred.
- **Other regulatory liabilities:** This includes various regulatory liabilities that individually are relatively small in relation to the total regulatory liability balance. Other regulatory liabilities will be credited over various periods, most of which range from one to five years.

Cash and Cash Equivalents

We consider investments that are highly liquid and that have 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.

Accounts Receivable

Receivables, which consist primarily of trade accounts receivable, were reduced by allowances for doubtful accounts of $6.3 million at December 31, 2006, and $5.2 million at December 31, 2005.

Inventories and Supplies

We state inventories and supplies at average cost.

Property, Plant and Equipment

We record the value of property, plant and equipment 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 funds used to finance construction projects. The AFUDC rate was 5.3% in 2006, 4.2% in 2005 and 3.8% in 2004. We capitalize the cost of additions to utility plant and replacement units of property. We capitalized AFUDC of $4.1 million in 2006, $2.7 million in 2005 and $1.8 million in 2004.

We charge maintenance costs and replacement of minor items of property to expense as incurred, except for maintenance costs incurred for our refueling outages at Wolf Creek. As authorized by regulators, we amortize these amounts to expense ratably over the 18-month period between such scheduled outages. Normally, when a unit of depreciable property is retired, we charge to accumulated depreciation the original cost, less salvage value.

Depreciation

We depreciate utility plant using a straight-line method at rates based on the estimated remaining useful lives of the assets. These rates are based on an average annual composite basis using group rates that approximated 2.7% in 2006, 2.5% in 2005 and 2.6% in 2004.

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

	Years
Fossil fuel generating facilities	15 to 75
Nuclear fuel generating facility	40 to 60
Transmission facilities	42 to 65
Distribution facilities	19 to 65
Other	5 to 35

In its order on December 28, 2005, the KCC approved a change in our depreciation rates. This change increased our depreciation expense by approximately $8.8 million.

Nuclear Fuel

We record as property, plant and equipment our share of the cost of nuclear fuel used in the process of refinement, conversion, enrichment and fabrication. We reflect this at original cost and amortize such amounts to fuel expense 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 $19.6 million as of December 31, 2006 and $24.2 million as of December 31, 2005. Spent nuclear fuel charged to fuel and purchased power was $18.8 million in 2006, $18.0 million in 2005 and $19.3 million in 2004.

Cash Surrender Value of Life Insurance

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

As of December 31,	2006	2005
	(In Thousands)	
Cash surrender value of policies	$1,053,231	$1,014,198
Borrowings against policies	(971,892)	(936,329)
Corporate-owned life insurance, net	$ 81,339	$ 77,869

We record income for increases in cash surrender value and death proceeds. We offset against policy income the interest expense that we incur on policy loans. Income recognized from death proceeds is highly variable from period to period. Death benefits approximated $18.9 million in 2006, $9.5 million in 2005 and $2.0 million in 2004.

Revenue Recognition — Energy Sales

We record revenue as electricity is delivered. Amounts delivered to individual customers are determined through the systematic monthly readings of customer meters. At the end of each month, the electric usage from the last meter reading is estimated and corresponding unbilled revenue is recorded.

The accuracy of the unbilled revenue estimate is affected by factors that include fluctuations in energy demands, weather, line losses and changes in the composition of customer classes. We had estimated unbilled revenue of $38.4 million as of December 31, 2006 and $42.1 million as of December 31, 2005.

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

Income Taxes

We use the asset and liability method of accounting for income taxes as required by SFAS No. 109, "Accounting for Income Taxes." Under the asset and liability method, we recognize deferred tax assets and liabilities for the future tax consequences attributable to temporary differences between the financial statement carrying

amounts and the tax basis of existing assets and liabilities. We recognize the future tax benefits to the extent that realization of such benefits is more likely than not. We amortize deferred investment tax credits over the lives of the related properties.

Sales Taxes

We account for the collection and remittance of sales tax on a net basis. As a result, these amounts are not reflected in the consolidated statements of income.

Dilutive Shares

We report basic earnings per share applicable to equivalent common stock based on the weighted average number of common shares outstanding and shares issuable in connection with vested restricted share units (RSU) during the period reported. Diluted earnings 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). We discontinued the ESPP effective January 1, 2005. The dilutive effect of shares issuable under the ESPP and our stock-based compensation plans is computed using the treasury stock method.

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

Year Ended December 31,	2006	2005	2004
DENOMINATOR FOR BASIC AND DILUTED EARNINGS PER SHARE:			
Denominator for basic earnings per share — weighted average equivalent shares	87,509,800	86,855,485	82,941,374
Effect of dilutive securities:			
Employee stock purchase plan shares	—	—	17,515
Employee stock options	788	1,750	1,943
Restricted share units	589,352	552,423	680,216
Denominator for diluted earnings per share — weighted average shares	88,099,940	87,409,658	83,641,048
Potentially dilutive shares not included in the denominator because they are antidilutive	158,080	214,340	217,375

Supplemental Cash Flow Information

Year Ended December 31,	2006	2005	2004
		(In Thousands)	
CASH PAID FOR:			
Interest on financing activities, net of amount capitalized	$ 88,872	$ 87,634	$ 127,993
Income taxes	72,407	772	1,162
NON-CASH INVESTING TRANSATIONS:			
Property, plant and equipment additions	29,134	10,800	13,513
NON-CASH FINANCING TRANSACTIONS:			
Issuance of common stock for reinvested dividends and RSUs	10,094	11,728	14,674
Assets acquired through capital leases	4,491	3,716	3,272

New Accounting Pronouncements

SFAS No. 159 — The Fair Value Option for Financial Assets and Financial Liabilities

In February 2007, the Financial Accounting Standards Board (FASB) released SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities — Including an amendment to FASB Statement No. 115." SFAS No. 159 permits entities to choose to measure many financial instruments and certain other items at fair value. A business entity shall report unrealized gains and losses on items for which fair value option has been elected in earnings at each subsequent reporting date. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. We anticipate adopting the guidance effective January 1, 2008. We are currently evaluating what impact the adoption of SFAS No. 159 will have on our consolidated financial statements.

SFAS No. 157 — Fair Value Measurements

In September 2006, FASB released SFAS No. 157, "Fair Value Measurements." SFAS No. 157 defines fair value, establishes a framework for measuring fair value in GAAP, and expands disclosures about fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007 with the cumulative effect of the change in accounting principle recorded as an adjustment to opening retained earnings. We anticipate adopting the guidance effective January 1, 2008. We are currently evaluating what impact the adoption of SFAS No. 157 will have on our consolidated financial statements.

FIN 48 — Accounting for Uncertainty in Income Taxes

In July 2006, FASB released FASB Interpretation No. (FIN) 48, "Accounting for Uncertainty in Income Taxes — an Interpretation of FASB Statement No. 109." FIN 48 prescribes a comprehensive model for how companies should recognize, measure and disclose in their financial statements uncertain tax positions taken, or expected to be taken, on a tax return. It also provides guidance on derecognizing, classification, interest and penalties, accounting in interim periods, disclosure, and transition. FIN 48 is effective for fiscal years beginning after December 15, 2006 with the cumulative effect of the change in accounting principle recorded as an adjustment to opening retained earnings.

We will adopt the guidance effective January 1, 2007. As of this date, we continue to evaluate what impact the adoption of FIN 48 will have on our consolidated financial statements. We do not expect the adoption of FIN 48 to have a material impact on our consolidated financial statements.

3. RATE MATTERS AND REGULATION

Changes in Rates

In accordance with a 2003 KCC Order, on May 2, 2005, we filed applications with the KCC for it to review our retail electric rates. On December 28, 2005, the KCC issued an order (2005 KCC Order) authorizing changes in our rates, which we began billing in the first quarter of 2006, and approving various other changes in our rate structures. In April 2006, interveners to the rate review filed appeals with the Kansas Court of Appeals challenging various aspects of the 2005 KCC Order. On July 7, 2006, the Kansas Court of Appeals reversed and remanded for further consideration by the KCC three elements of the 2005 KCC Order. The balance of the 2005 KCC Order was upheld.

The Kansas Court of Appeals held: (i) the KCC's approval of a transmission delivery charge, in the circumstances of this case, violated the Kansas statutes that authorize a transmission delivery charge, (ii) the KCC's approval of recovery of terminal net salvage, adjusted for inflation, in our depreciation rates was not supported by substantial competent evidence, and (iii) the KCC's reversal of its prior rate treatment of the La Cygne Generating Station (La Cygne) unit 2 sale-leaseback transaction was not sufficiently justified and was thus unreasonable, arbitrary and capricious.

On February 8, 2007, the KCC issued an order in response to the Kansas Court of Appeals' decision regarding the 2005 KCC Order. In its February 8, 2007 Order the KCC: (i) confirmed its original decision regarding its treatment of the La Cygne unit 2 sale-leaseback transaction; (ii) in lieu of a transmission delivery charge, ruled that it intends to permit us to recover our transmission related costs in a manner similar to how we recover our other costs; and (iii) reversed itself with regard to the inclusion in depreciation rates of a component for terminal net salvage. The February 8, 2007 KCC Order requires us to refund to our customers the amount we have collected related to terminal net salvage. We have recorded a regulatory liability at December 31, 2006 in the amount of $16.4 million related to this item.

FERC Proceedings

Request for Change in Transmission Rates

On May 2, 2005, we filed applications with the Federal Energy Regulatory Commission (FERC) that proposed a formula transmission rate providing for annual adjustments to our transmission costs. This is consistent with our proposals filed with the KCC on May 2, 2005 to charge retail customers separately for transmission service through a transmission delivery charge. The proposed FERC transmission rates became effective, subject to refund, December 1, 2005. On November 7, 2006 FERC issued an order reflecting the unanimous settlement reached by the parties to the proceeding. The settlement modified the rates we proposed and requires us to refund $3.4 million, which includes the amount we collected in the interim rates since December 2005 and interest on that amount.

4. ACCOUNTS RECEIVABLE SALES PROGRAM

We terminated our accounts receivable sales program in March 2006. The receivables sold by WR Receivables, Inc. (WR Receivables), our wholly owned subsidiary, during 2005 to the bank and commercial paper conduit are not reflected in the accounts receivable balance in the accompanying consolidated balance sheets. The amounts sold to the bank and commercial paper conduit were $65.0 million as of December 31, 2005. We recorded this activity on the consolidated statements of cash flows for the year ended December 31, 2005 in the "accounts receivable, net" line of cash flows from operating activities.

The following table summarizes accounts receivable information for WR Receivables.

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

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

As of December 31,	2005
	(In Thousands)
Customer accounts receivable	$128,868
Allowance for uncollectible accounts	(4,933)
Customer accounts receivable, net	123,935
Other accounts receivable	1,076
Other allowance for uncollectible accounts	(300)
Total balance sheet accounts receivable, net	124,711
Customer accounts receivable sold	65,000
Total accounts receivable managed	$189,711
Net uncollectible accounts written off	$ 3,862
Delinquent customer accounts receivable over 60 days	$ 2,994

5. FINANCIAL INSTRUMENTS, ENERGY MARKETING AND RISK MANAGEMENT

Values of Financial Instruments

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

Cash and cash equivalents, short-term borrowings and variable-rate debt are carried at cost, which approximates fair value. The nuclear decommissioning trust is recorded at fair value, which is estimated based on the quoted market prices as of December 31, 2006 and 2005. See Note 6, "Financial Investments and Trading Securities," for additional information about our nuclear decommissioning trust. The fair value of fixed-rate debt is estimated based on quoted market prices for the same or similar issues or on the current rates offered for instruments of the same remaining maturities and redemption provisions.

The recorded amounts of accounts receivable and other current financial instruments approximate fair value.

We base estimates of fair value on information available as of December 31, 2006 and 2005. These fair value estimates have not been comprehensively revalued for the purpose of these financial statements since that date and current estimates of fair value may differ from the amounts below. The carrying values and estimated fair values of our financial instruments are as shown in the table below.

	Carrying Value		Fair Value	
As of December 31,	**2006**	**2005**	**2006**	**2005**
		(In Thousands)		
Fixed-rate debt, net of current maturities	$1,294,405	$1,344,406	$1,277,497	$1,339,452

Derivative Instruments

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

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

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

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

We are also exposed to commodity price changes. We use derivative contracts for non-trading purposes and a mix of various fuel types primarily to reduce exposure relative to the volatility of market and commodity prices. The wholesale power market is extremely volatile in price and supply. This volatility impacts our costs of power purchased and our participation in energy trades. If we were unable to generate an adequate supply of electricity for our customers, we would purchase power in the wholesale market to the extent it is available, subject to possible transmission constraints, and/or implement curtailment or interruption procedures as permitted in our tariffs and terms and conditions of service.

We use various fossil fuel types, including coal, natural gas and oil, to operate our plants. A significant portion of our coal requirements are purchased under long-term contracts.

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

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

6. FINANCIAL INVESTMENTS AND TRADING SECURITIES

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

Trading Securities

We have investments in trust assets securing certain executive benefits that are classified as trading securities. We include any unrealized gains or losses on these securities in investment earnings on our consolidated statements of income. There was an unrealized gain of $1.7 million as of December 31, 2006 and an unrealized loss of $0.3 million as of December 31, 2005.

Available-for-Sale Securities

We hold investments in debt and equity securities in a trust fund for the purpose of funding the decommissioning of Wolf Creek. We have classified these investments in debt and equity securities as available-for-sale and have recorded all such investments at their fair market value as of December 31, 2006 and 2005. Investments by the nuclear decommissioning trust fund are allocated 63% to equity securities, 33% to fixed-income securities and 4% to cash and cash equivalents. Fixed-income investments are limited to U.S. government or agency securities, municipal bonds, or corporate securities. Using the specific identification method to determine cost, the gross realized gains on those sales were $7.5 million in 2006, $3.2 million in 2005 and $4.3 million in 2004. We reflect net realized and unrealized gains and losses in regulatory liabilities on our consolidated balance sheets. This reporting is consistent with the method we use to account for the decommissioning costs recovered in rates. Gains or losses on assets in the trust fund could result in lower or higher funding requirements for decommissioning costs, which we believe would be reflected in electric rates paid by our customers.

The following table presents the costs and fair values of investments in debt and equity securities in the nuclear decommissioning trust fund as of December 31, 2006 and 2005. Changes in the fair value of the trust fund are recorded as an increase or decrease to the regulatory liability recorded in connection with the decommissioning of Wolf Creek.

Security Type	Cost	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
		(In Thousands)		
2006:				
Debt securities	$ 36,947	$ 181	$ —	$ 37,128
Equity securities	57,202	12,466	—	69,668
Cash equivalents	4,339	—	—	4,339
Total	$ 98,488	$ 12,647	$ —	$ 111,135
2005:				
Debt securities	$ 25,196	$ —	$ (309)	$ 24,887
Equity securities	51,591	14,731	—	66,322
Cash equivalents	9,594	—	—	9,594
Total	$ 86,381	$ 14,731	$ (309)	$ 100,803

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

As of December 31, 2006	Cost	Fair Value
	(In Thousands)	
Less than 5 years	$ 3,314	$ 3,315
5 years to 10 years	6,549	6,536
Due after 10 years	16,903	16,892
Sub-total	26,766	26,743
Fixed Income Fund	10,181	10,385
Total	$ 36,947	$ 37,128

The following table presents the fair value and the gross unrealized losses of the available-for-sale securities held in the nuclear decommissioning trust fund that were not deemed to be other-than-temporarily impaired, aggregated by investment category and the length of time that individual securities have been in a continuous unrealized loss position, at December 31, 2006.

	Less than 12 Months		12 Months or Greater		Total	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
			(In Thousands)			
Debt securities	$ 8,931	$ (152)	$ 738	$(14)	$ 9,669	$ (166)
Equity securities	9,006	(1,214)	282	(44)	9,288	(1,258)
Total	$17,937	$(1,366)	$1,020	$(58)	$18,957	$(1,424)

7. PROPERTY, PLANT AND EQUIPMENT

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

As of December 31,	2006	2005
	(In Thousands)	
Electric plant in service	$ 6,066,954	$ 5,937,760
Electric plant acquisition adjustment	802,318	802,318
Accumulated depreciation	(2,979,159)	(2,880,613)
	3,890,113	3,859,465
Construction work in progress	142,351	60,561
Nuclear fuel, net	39,109	27,672
Net utility plant	4,071,573	3,947,698
Non-utility plant in service	34	34
Net property, plant and equipment	$ 4,071,607	$ 3,947,732

We recorded depreciation expense on utility property, plant and equipment of $159.9 million in 2006, $130.1 million in 2005 and $148.9 million in 2004.

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 as of December 31, 2006 is shown in the table below.

	Our Ownership as of December 31, 2006					
	In-Service Dates	Investment	Accumulated Depreciation	Construction Work in Progress	Net MW	Ownership Percent
		(Dollars in Thousands)				
La Cygne unit 1[a]	June 1973	$ 228,369	$127,152	$32,530	370.0	50
Jeffrey unit 1[b]	July 1978	318,661	170,761	6,590	613.0	84
Jeffrey unit 2[b]	May 1980	307,681	152,351	5,152	613.0	84
Jeffrey unit 3[b]	May 1983	455,668	213,076	4,907	613.0	84
Jeffrey wind 1[b]	May 1999	874	328	—	0.6	84
Jeffrey wind 2[b]	May 1999	874	328	—	0.6	84
Wolf Creek[c]	Sept. 1985	1,401,443	628,965	28,661	548.0	47
State Line[d]	June 2001	106,571	23,850	362	204.0	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. We include in operating expenses on our consolidated statements of income our share of operating expenses of the above plants, as well as such expenses for a 50% undivided interest in La Cygne unit 2 (representing 341 MW capacity) sold and leased back to KGE in 1987. Our share of other transactions associated with the plants is included in the appropriate classification on our consolidated financial statements.

9. SHORT-TERM DEBT

A syndicate of banks provides us a revolving credit facility on a committed basis totaling $500.0 million. The facility matures on March 17, 2011. So long as there is no default or event of default under the revolving credit facility, we may elect to extend the term of the credit facility for one year. This one year extension can be requested twice during the term of the facility, subject to lender participation. The facility allows us to borrow up to an aggregate amount of $500.0 million, including letters of credit up to a maximum aggregate amount of $150.0 million. We may elect, subject to FERC approval, to increase the aggregate amount of borrowings under the facility to $750.0 million by increasing the commitment of one or more lenders who have agreed to such increase, or by adding one or more new lenders with the consent of the Administrative Agent and any letter of credit issuing bank, which will not be unreasonably withheld, so long as there is no default or event of default under the revolving credit facility. As of December 31, 2006, we had borrowings of $160.0 million and $32.0 million of letters of credit outstanding under this facility.

Information regarding our short-term borrowings is as follows.

As of December 31,	2006	2005
	(Dollars in Thousands)	
Weighted average short-term debt outstanding during the year	$122,392	$9,661
Weighted daily average interest rates during the year, excluding fees	5.71%	4.77%

Our interest expense on short-term debt was $7.6 million in 2006, $1.3 million in 2005 and $1.1 million in 2004.

10. LONG-TERM DEBT

Outstanding Debt

The following table summarizes our long-term debt outstanding.

As of December 31,	2006	2005
	(In Thousands)	
Westar Energy		
First mortgage bond series:		
6.000% due 2014	$ 250,000	$ 250,000
5.150% due 2017	125,000	125,000
5.950% due 2035	125,000	125,000
5.100% due 2020	250,000	250,000
5.875% due 2036	150,000	150,000
	900,000	900,000
Pollution control bond series:		
Variable due 2032, 3.65% as of December 31, 2006; 3.30% as of December 31, 2005	45,000	45,000
Variable due 2032, 3.55% as of December 31, 2006; 3.20% as of December 31, 2005	30,500	30,500
5.000% due 2033	58,340	58,340
	133,840	133,840
7.125% unsecured senior notes due 2009	145,078	145,078
	145,078	145,078
KGE		
First mortgage bond series:		
6.200% due 2006	—	100,000
	—	100,000
Pollution control bond series:		
5.100% due 2023	13,488	13,488
Variable due 2027, 3.50% as of December 31, 2006; 3.35% as of December 31, 2005	21,940	21,940
5.300% due 2031	108,600	108,600
5.300% due 2031	18,900	18,900
2.650% due 2031 and putable 2006	—	100,000
Variable due 2031, 3.47% as of December 31, 2006; 3.49% as of December 31, 2005	100,000	100,000
Variable due 2032, 3.45% as of December 31, 2006; 3.30% as of December 31, 2005	14,500	14,500
Variable due 2032, 3.44% as of December 31, 2006; 3.25% as of December 31, 2005	10,000	10,000
4.85% due 2031	50,000	—
Variable due 2031, 3.85% as of December 31, 2006	50,000	—
	387,428	387,428
Unamortized debt discount[a]	(3,081)	(3,356)
Long-term debt due within one year	—	(100,000)
Long-term debt, net	$1,563,265	$1,562,990

[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. We must 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 $2.0 billion, unless amended. First mortgage bonds are secured by utility assets. Amounts of additional bonds that may be issued are subject to property, earnings and certain restrictive provisions, except in connection with certain refundings, of each mortgage. As of December 31, 2006, based on an assumed interest rate of 6%, $378.8 million principal amount of additional first mortgage bonds could be issued under the most restrictive provisions in Westar Energy's mortgage. As of December 31, 2006, based on an assumed interest rate of 6%, approximately $908.1 million principal amount of additional KGE first mortgage bonds could be issued under the most restrictive provisions in KGE's mortgage.

On June 1, 2006, we refinanced $100.0 million of pollution control bonds, which were to mature in 2031. We replaced this issue with two new pollution control bond series of $50.0 million each. One series carries an interest rate of 4.85% and matures in 2031. The second series carries a variable interest rate and also matures in 2031.

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

On June 30, 2005, Westar Energy sold $400.0 million aggregate principal amount of Westar Energy first mortgage bonds, consisting of $150.0 million of 5.875% bonds maturing in 2036 and $250.0 million of 5.1% bonds maturing in 2020. On July 27, 2005, proceeds from the offering were used to redeem the outstanding $365.0 million aggregate principal amount of Westar Energy's 7.875% first mortgage bonds due 2007, together with accrued interest and a call premium equal to approximately 6% of the principal outstanding, and for general corporate purposes. The call premium is recorded as a regulatory asset and is being amortized over the term of the new 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. The call premium is recorded as a regulatory asset and is being amortized over the term of the new bonds.

Debt Covenants

Some of our debt instruments contain restrictions that require us to maintain leverage ratios as defined in the agreements. We calculate these ratios in accordance with our credit agreements. We use these ratios solely to determine compliance with our various debt covenants. We were in compliance with these covenants as of December 31, 2006.

Maturities

Maturities of long-term debt as of December 31, 2006 are as follows.

Year	Principal Amount
	(In Thousands)
2007	$ —
2008	—
2009	145,078
2010	—
Thereafter	1,421,268
Total long-term debt maturities	$1,566,346

Our interest expense on long-term debt was $91.0 million in 2006, $107.8 million in 2005 and $141.1 million in 2004.

11. INCOME TAXES

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

Year Ended December 31,	2006	2005	2004
		(In Thousands)	
Income tax expense (benefit) from continuing operations:			
Current income taxes:			
Federal	$46,211	$30,132	$ 41,649
State	14,303	4,829	(2,991)
Deferred income taxes:			
Federal	(1,150)	24,831	(2,285)
State	578	3,511	1,858
Investment tax credit amortization	(3,630)	(2,790)	(4,788)
Income tax expense from continuing operations	56,312	60,513	33,443
Income tax expense (benefit) from discontinued operations:			
Current income taxes:			
Federal	—	29	(116,903)
State	—	7	(22,569)
Deferred income taxes:			
Federal	—	370	77,019
State	—	84	17,172
Income tax expense (benefit) from discontinued operations	—	490	(45,281)
Total income tax expense (benefit)	$56,312	$61,003	$(11,838)

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

December 31,	2006	2005
	(In Thousands)	
Current deferred tax assets	$ 853	$ 19,211
Non-current deferred tax liabilities	906,311	911,135
Net deferred tax liabilities	$905,458	$891,924

The tax effect of the temporary differences and carryforwards that comprise our deferred tax assets and deferred tax liabilities are summarized in the following table.

December 31,	2006	2005
	(In Thousands)	
Deferred tax assets:		
Deferred gain on sale-leaseback	$ 54,978	$ 57,297
General business credit carryforward[a]	—	15,679
Accrued liabilities	30,531	20,390
Disallowed costs	15,955	16,617
Long-term energy contracts	9,314	10,289
Deferred employee benefit costs	77,155	—
Capital loss carryforward[b]	219,795	227,668
Other	74,963	79,547
Total gross deferred tax assets	482,691	427,487
Less: Valuation allowance[b]	223,227	233,211
Deferred tax assets	$ 259,464	$ 194,276
Deferred tax liabilities:		
Accelerated depreciation	$ 642,493	$ 644,082
Acquisition premium	227,999	235,167
Amounts due from customers for future income taxes, net	160,147	166,632
Deferred employee benefit costs	74,111	—
Other	60,172	40,319
Total deferred tax liabilities	$1,164,922	$1,086,200
Net deferred tax liabilities	$ 905,458	$ 891,924

[a] *As of December 31, 2005, we had available general business tax credits of $15.7 million generated from affordable housing partnerships in which we sold the majority of our interests in 2001. These tax credits expire beginning 2019 through 2025. We believe these tax credits will be fully utilized in 2006.*

[b] *As of December 31, 2006, we have a net capital loss of $552.6 million available to offset any future capital gains through 2009. However, as we do not expect to realize any significant capital gains in the future, a valuation allowance of $219.8 million has been established. In addition, a valuation allowance of $3.4 million has been established for certain deferred tax assets related to the write-down of other investments. The total valuation allowance related to deferred tax assets was $223.2 million as of December 31, 2006 and $233.2 million as of December 31, 2005. The net reduction in valuation allowance of $10.0 million was due primarily to capital gains realized in 2006.*

In accordance with various rate orders, we have reduced rates to reflect the tax benefits associated with certain tax deductions. We believe it is probable that the net future increases in income taxes payable will be recovered from customers when these temporary tax benefits reverse. We have recorded a regulatory asset for these amounts. We also have recorded a regulatory liability for our obligation to reduce rates charged customers for deferred taxes recovered from customers at corporate tax rates higher than the current tax rates. The rate reduction will occur as the temporary differences resulting in the excess deferred tax liabilities reverse. The tax-related regulatory assets and liabilities as well as unamortized investment tax credits are also temporary differences for which deferred income taxes have been provided. The net deferred tax liability related to these temporary differences is classified above as amounts due from customers for future income taxes.

The effective income tax rates set forth below are for continuing operations and discontinued 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,	2006	2005	2004
Statutory federal income tax rate from continuing operations	35.0%	35.0%	35.0%
Effect of:			
State income taxes	4.4	2.8	1.0
Amortization of investment tax credits	(1.6)	(1.4)	(3.6)
Corporate-owned life insurance policies	(8.3)	(6.9)	(9.0)
Accelerated depreciation flow through and amortization	1.4	1.2	5.3
Income tax reserve adjustment	0.7	0.6	(5.3)
Capital loss utilization	(4.0)	(0.8)	(2.2)
Other	(2.2)	0.5	3.8
Effective income tax rate from continuing operations	25.4%	31.0%	25.0%
Statutory federal income tax rate from discontinued operations	—%	35.0%	35.0%
Effect of:			
State income taxes	—	4.8	(6.4)
Tax loss in excess of book loss	—	—	(160.6)
Valuation allowance capital loss	—	—	(3.9)
Other	—	—	0.8
Effective income tax rate from discontinued operations	—%	39.8%	(135.1)%

We file income tax returns in the U.S. and various state jurisdictions. As a matter of course, we remain subject to ongoing federal and state tax examinations. We have extended the federal statute of limitations for years 1995 through 2002 until December 31, 2007.

As of December 31, 2006 and 2005, we recorded reserves for uncertain tax positions of $53.6 million and $50.8 million, respectively. The tax positions may involve income, deductions or credits reported in prior year income tax returns that we believe were treated properly on such tax returns. The tax returns containing these tax reporting positions are currently under audit or will likely be audited by the Internal Revenue Service or other taxing authorities. The timing of the resolution of these audits is uncertain. If the positions taken on the tax returns are ultimately upheld or not challenged within the time available for such challenges, we will reverse these tax provisions to income. If the positions taken on the tax returns are determined to be inappropriate, we may be required to make cash

payments for taxes and interest. The reserves are determined based on our best estimate of probable assessments by the applicable taxing authorities and are adjusted, from time to time, based on changing facts and circumstances.

As of December 31, 2006 and 2005, we also had a reserve of $6.9 million and $6.1 million, respectively, for probable assessments of taxes other than income taxes.

In July 2006 FASB released FIN 48, which prescribes a comprehensive model for how companies should recognize, measure and disclose in their financial statements uncertain tax positions taken, or expected to be taken, on a tax return. It also provides guidance on derecognizing, classification, interest and penalties, accounting in interim periods, disclosure, and transition. FIN 48 is effective for fiscal years beginning after December 15, 2006 with the cumulative effect of the change in accounting principle recorded as an adjustment to opening retained earnings.

We will adopt the guidance effective January 1, 2007. As of this date, we continue to evaluate what impact the adoption of FIN 48 will have on our consolidated financial statements. We do not expect the adoption of FIN 48 to have a material impact on our consolidated financial statements.

12. EMPLOYEE BENEFIT PLANS

Pension

We maintain a qualified non-contributory defined benefit pension plan covering substantially all of our employees. For the majority 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 funding policy for the pension plan is to contribute amounts sufficient to meet the minimum funding requirements under the PPA plus additional amounts as considered appropriate. Non-union employees hired after December 31, 2001 are covered by the same defined benefit plan with benefits derived from a cash balance account formula. We also maintain a non-qualified Executive Salary Continuation Plan for the benefit of certain current and retired officers.

In addition to providing pension benefits, we provide certain post-retirement health care and life insurance benefits for substantially all retired employees. The cost of post-retirement benefits are accrued during an employee's years of service and recovered through rates. We fund the portion of net periodic post-retirement benefit costs that are included in rates.

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

In September 2006, FASB released SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Post-retirement Plans — An Amendment of FASB Statements No. 87, 88, 106, and 132(R)." Under the new standard, companies must recognize a net liability or asset to report the funded status of their defined benefit pension and other post-retirement benefit plans on their balance sheets. On December 31, 2006 we adopted the recognition and disclosure provisions of SFAS No. 158. The effect of adopting SFAS No. 158 on our financial condition at December 31, 2006 has been included in the accompanying consolidated financial statements. We received an accounting authority order from the KCC to recognize as a regulatory asset the pension and post-retirement liabilities that otherwise would have been charged to other comprehensive income. SFAS No. 158 did not have an effect on our consolidated financial condition at December 31, 2005.

The incremental effect of adopting the provisions of SFAS No. 158 on our statement of financial position at December 31, 2006, including the effect on our portion of Wolf Creek's pension and post-retirement plans, are presented in the following table. The adoption of SFAS No. 158 had no effect on our consolidated statement of income for the year ended December 31, 2006, or for any prior period presented.

Incremental Effect of Applying SFAS No. 158 on Individual Line Items in the Consolidated Balance Sheet as of December 31, 2006

	Before SFAS No. 158	Adjustments	After SFAS No. 158
CURRENT ASSETS:			
Regulatory assets	$ —	$ 17,582	$ 17,582
Total Current Assets	—	17,582	17,582
OTHER ASSETS:			
Regulatory assets	—	168,732	168,732
Other	14,412	(14,412)	—
Total Other Assets	14,412	154,320	168,732
TOTAL ASSETS	14,412	171,902	186,314
CURRENT LIABILITIES:			
Other	—	2,467	2,467
Total Current Liabilities	—	2,467	2,467
LONG-TERM LIABILITIES:			
Deferred income taxes	(16,948)	11,466	(5,482)
Accrued employee benefits	71,274	135,999	207,273
Total Long-Term Liabilities	54,326	147,465	201,791
SHAREHOLDERS' EQUITY:			
Accumulated other comprehensive (loss) income, net	(21,970)	21,970	—
Total Shareholders' Equity	(21,970)	21,970	—
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 32,356	$171,902	$204,258

The following tables summarize the status of our pension and other post-retirement benefit plans.

As of December 31,	Pension Benefits 2006	Pension Benefits 2005	Post-retirement Benefits 2006	Post-retirement Benefits 2005
	(In Thousands)			
Change in Benefit Obligation:				
Benefit obligation, beginning of year	$549,132	$494,615	$128,185	$123,466
Service cost	9,178	6,735	1,492	1,615
Interest cost	30,522	28,764	6,875	7,049
Plan participants' contributions	—	—	3,380	3,380
Benefits paid	(28,345)	(28,581)	(11,306)	(11,825)
Assumption changes	(9,925)	43,264	(2,032)	3,714
Actuarial losses (gains)	1,166	430	(2,048)	279
Amendments	—	3,905	—	507
Benefit obligation, end of year	$551,728	$549,132	$124,546	$128,185
Change in Plan Assets:				
Fair value of plan assets, beginning of year	$422,300	$422,602	$44,196	$32,612
Actual return on plan assets	35,302	26,604	3,374	1,276
Employer contribution	20,750	—	12,200	18,600
Plan participants' contributions	—	—	3,380	3,380
Part D Reimbursements	—	—	677	—
Benefits paid	(26,528)	(26,906)	(11,049)	(11,672)
Fair value of plan assets, end of year	$451,824	$422,300	$52,778	$44,196
Funded status	$(99,904)	$(126,832)	$(71,768)	$(83,989)
Unrecognized net loss	N/A	118,821	N/A	33,757
Unrecognized transition obligation, net	N/A	—	N/A	27,839
Unrecognized prior service cost	N/A	17,051	N/A	(424)
Prepaid benefit (accrued) costs	$(99,904)	$9,040	$(71,768)	$(22,817)
Amounts Recognized in the Balance Sheets Consist Of:				
Current liability	$(1,930)	$N/A	$—	$N/A
Noncurrent liability	(97,974)	N/A	(71,768)	N/A
Prepaid benefit cost	N/A	25,983	N/A	N/A
Accrued benefit liability	N/A	(16,943)	N/A	(22,817)
Additional minimum liability	N/A	(80,758)	N/A	N/A
Intangible asset	N/A	17,051	N/A	N/A
Accumulated other comprehensive income	N/A	63,707	N/A	N/A
Net amount recognized	$(99,904)	$9,040	$(71,768)	$(22,817)
Amounts Recognized in Regulatory Assets Consist of:				
Net actuarial loss	$102,172	$N/A	$26,570	$N/A
Prior service cost	13,926	N/A	17	N/A
Transition obligation	—	N/A	23,909	N/A
Net amount recognized	$116,098	$N/A	$50,496	$N/A

As of December 31,	Pension Benefits 2006	Pension Benefits 2005	Post-retirement Benefits 2006	Post-retirement Benefits 2005
	(Dollars in Thousands)			
Pension Plans With a Projected Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$551,728	$549,132	$N/A	$N/A
Accumulated benefit obligation	483,511	494,018	N/A	N/A
Fair value of plan assets	451,824	422,300	N/A	N/A
Pension Plans With an Accumulated Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$551,728	$549,132	$N/A	$N/A
Accumulated benefit obligation	483,511	494,018	N/A	N/A
Fair value of plan assets	451,824	422,300	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	$124,546	$128,185
Fair value of plan assets	N/A	N/A	52,778	44,196
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Benefit Obligation:				
Discount rate	5.90%	5.65%	5.80%	5.65%
Compensation rate increase	4.00%	3.50%	4.00%	3.50%

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

We use an interest rate yield curve to make judgments pursuant to Emerging Issues Task Force (EITF) No. D-36, "Selection of Discount Rates Used for Measuring Defined Benefit Pension Obligations and Obligations of Post Retirement Benefit Plans Other Than Pensions." The yield curve is constructed based on the yields on over 500 high-quality, non-callable corporate bonds with maturities between zero and 30 years. A theoretical spot rate curve constructed from this yield curve is then used to discount the annual benefit cash flows of our pension plan and develop a single-point discount rate matching the plan's payout structure.

We amortize the prior service cost (benefit) on a straight-line basis over the average future service of the active employees (plan participants) benefiting under the plan at the time of the amendment. The net actuarial loss subject to amortization is amortized on a straight-line basis over the average future service of active plan participants benefiting under the plan, without application of the amortization corridor described in SFAS No. 87, "Employers' Accounting for Pensions" and SFAS No. 106, "Employers' Accounting for Post-retirement Benefits Other Than Pensions."

Year Ended December 31,	Pension Benefits 2006	2005	2004
	(Dollars in Thousands)		
Components of Net Periodic Cost (Benefit):			
Service cost	$ 9,178	$ 6,735	$ 6,110
Interest cost	30,522	28,764	28,319
Expected return on plan assets	(35,939)	(36,272)	(38,561)
Amortization of unrecognized:			
Transition obligation, net	—	—	—
Prior service costs/(benefit)	2,892	2,761	2,762
Actuarial loss, net	8,759	5,347	2,525
Net periodic cost	$15,412	$ 7,335	$ 1,155
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost (Benefit):			
Discount rate	5.65%	5.90%	6.10%
Expected long-term return on plan assets	8.50%	8.75%	9.00%
Compensation rate increase	3.50%	3.00%	3.10%

Year Ended December 31,	Post-retirement Benefits 2006	2005	2004
	(Dollars in Thousands)		
Components of Net Periodic Cost (Benefit):			
Service cost	$ 1,492	$ 1,615	$ 1,487
Interest cost	6,875	7,049	6,774
Expected return on plan assets	(2,971)	(2,552)	(1,999)
Amortization of unrecognized:			
Transition obligation, net	3,931	3,931	3,931
Prior service costs/(benefit)	(415)	(467)	(467)
Actuarial loss, net	2,001	1,934	1,172
Net periodic cost	$10,913	$11,510	$ 10,898
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost (Benefit):			
Discount rate	5.65%	5.90%	6.10%
Expected long-term return on plan assets	7.75%	8.25%	8.50%
Compensation rate increase	3.50%	3.00%	3.10%

The estimated amounts that will be amortized from regulatory assets into net periodic benefit cost in 2007 are as follows:

	Pension Benefits	Other Post-retirement Benefits
Actuarial loss	$ 7,625	$1,830
Prior service (credit)/cost	2,535	(415)
Transition obligation	—	3,931
Total	$10,160	$5,346

We base the expected long-term rate of return on plan assets 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 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 $4.6 million. The subsidy also decreased the net periodic post-retirement benefit cost by approximately $0.6 million for 2006.

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

As of December 31,	2006	2005
Health care cost trend rate assumed for next year	9.00%	8.00%
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	2011	2009

The health care cost trend rate affects 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	$ 56	$ (62)
Effect on post-retirement benefit obligation	852	(943)

The asset allocation for the pension plans and the post-retirement benefit plans at the end of 2006 and 2005, and the target allocations for 2007, by asset category, are as shown in the following table.

Asset Category	Target Allocations 2007	Plan Assets 2006	2005
Pension Plans:			
Equity securities	65%	62%	65%
Debt securities	35%	35%	29%
Cash	0% - 5%	3%	6%
Total		100%	100%
Post-retirement Benefit Plans:			
Equity securities	65%	64%	40%
Debt securities	30%	28%	50%
Cash	5%	8%	10%
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.

The following table shows the expected cash flows for the pension plans and post-retirement benefit plans for future years.

	Pension Benefits		Post-retirement Benefits	
Expected Cash Flows	To/(From) Trust	To/(From) Company Assets	To/(From) Trust	To/(From) Company Assets
	(In Millions)			
Expected contributions:				
2007[a]	$ 11.8	$ 1.9	$11.4	$ 0.3
Expected benefit payments:				
2007	$ (26.1)	$(1.9)	$ (8.1)	$(0.3)
2008	(26.0)	(1.9)	(8.2)	(0.3)
2009	(26.1)	(1.8)	(8.3)	(0.3)
2010	(26.4)	(1.8)	(8.3)	(0.3)
2011	(27.0)	(1.8)	(8.4)	(0.3)
2012 – 2016	(155.7)	(9.0)	(43.5)	(1.5)

[a] *We expect to make a voluntary contribution to the Westar Energy pension trust in 2007. We estimate that amount to be $11.8 million.*

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 $4.8 million in 2006, $4.1 million in 2005 and $3.4 million in 2004.

Under our former qualified employee stock purchase plan established in 1999, full-time, non-union employees purchased 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. 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. As of December 31, 2006, awards of 3,772,823 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.

Effective January 1, 2006, we adopted SFAS No. 123 (revised 2004), "Share-Based Payment," (SFAS No. 123R) for stock-based compensation plans. Under SFAS No. 123R, all stock-based compensation is measured at the grant date, based on the fair value of the award, and is recognized as an expense in the consolidated statement of income over the requisite service period. On March 29, 2005, the Securities and Exchange Commission (SEC) staff issued Staff Accounting Bulletin (SAB) No. 107 on Share-Based Payment to express the views of the staff regarding the interaction between SFAS No. 123R and SEC rules and regulations as well as provide staff's view on valuation of stock-based compensation arrangements for public companies. The SAB No. 107 guidance was taken into consideration with the implementation of SFAS No. 123R.

We adopted SFAS No. 123R using the modified prospective transition method. Under the modified prospective transition method, we are required to record stock-based compensation expense for all awards granted after the adoption date and for the unvested portion of previously granted awards outstanding as of the adoption date. Compensation cost related to the unvested portion of previously granted awards is based on the grant-date fair value estimated in accordance with the original provisions of SFAS No. 123. Compensation cost for awards granted after the adoption date are based on the grant-date fair value estimated in accordance with the provisions of SFAS No. 123R. Since 2002, we have used RSUs exclusively for our stock-based compensation awards. RSUs are valued in the same manner under SFAS Nos. 123 and 123R.

The table below shows compensation expense and income tax benefits related to stock-based compensation arrangements that are included in our net income.

Twelve Months Ended December 31,	2006	2005	2004
	(In Thousands)		
Compensation expense	$3,395	$4,560	$8,141
Income tax benefits related to stock-based compensation arrangements	1,350	1,814	3,238

The incremental amount of stock-based compensation expense that was disclosed and not included in our consolidated statements of income for the years ended December 31, 2005 and 2004 was not material to our consolidated results of operations.

Restricted share unit (RSU) awards are grants that entitle the holder to receive shares of common stock as the awards vest. These RSU awards are defined in SFAS No. 123R as nonvested shares and do not include restrictions once the awards have vested. We measure the fair value of the RSU awards based on the market price of the underlying common stock as of the date of grant and recognize that cost as an expense in the consolidated statement of income over the requisite service period. The requisite service periods range from one to ten years. RSU awards issued after adoption of SFAS No. 123R with only service conditions that have a graded vesting schedule will be recognized as an expense in the consolidated statement of income on a straight-line basis over the requisite service period for the entire award. Awards issued prior to adoption of SFAS No. 123R will continue to be recognized as an expense in the consolidated statement of income on a straight-line basis over the requisite service period for each separately vesting portion of the award.

During the year ended December 31, 2006, our RSU activity was as follows:

As of December 31,	2006		2005		2004	
	Shares	Weighted-Average Grant Date Fair Value	Shares	Weighted-Average Grant Date Fair Value	Shares	Weighted-Average Grant Date Fair Value
	(In Thousands)		(In Thousands)		(In Thousands)	
Nonvested balance, beginning of year	1,094.5	$18.54	1,298.4	$17.50	1,913.7	$16.25
Granted	160.3	23.91	135.5	22.04	60.1	20.57
Vested	(306.6)	14.96	(336.0)	13.28	(668.4)	14.65
Forfeited	(14.8)	21.56	(3.4)	20.43	(7.0)	17.72
Nonvested balance, end of year	933.4	20.82	1,094.5	18.54	1,298.4	17.50

Total unrecognized compensation cost related to RSU awards was $4.4 million as of December 31, 2006. These costs are expected to be recognized over a remaining weighted-average period of 3.7 years. Upon adoption of SFAS No. 123R, we were required to charge $10.3 million of unearned stock compensation against additional paid-in capital. The total fair value of shares vested during the years ended December 31, 2006, 2005 and 2004, was $7.2 million, $7.5 million and $13.6 million, respectively. There were no modifications of awards during the years ended December 31, 2006, 2005 or 2004.

SFAS No. 123R requires that forfeitures be estimated over the vesting period, rather than being recognized as a reduction of compensation expense when the forfeiture actually occurs. The cumulative effect of the use of the estimated forfeiture method for prior periods upon adoption of SFAS No. 123R was not material.

RSU awards that can be settled in cash upon a change in control were reclassified from permanent equity to temporary equity upon adoption of SFAS No. 123R. As of December 31, 2006, we had $6.7 million of temporary equity on our consolidated balance sheet. If we determine it is probable that these awards will be settled in cash, the awards will be reclassified as a liability.

Stock options granted between 1997 and 2001 are completely vested and expire 10 years from the date of grant. All 160,480 outstanding options are exercisable. There were 7,225 options exercised and 51,885 options forfeited during the year ended December 31, 2006. We currently have no plans to issue new stock option awards.

Another component of the LTISA Plan is the Executive Stock for Compensation program, where in the past eligible employees were entitled to receive deferred stock in lieu of current cash compensation. Although this plan was discontinued in 2001, dividends will continue to be paid to plan participants on their outstanding plan balance until distribution. Plan participants were awarded 4,407 shares of common stock for dividends in 2006, 3,936 shares in 2005 and 4,422 shares in 2004. Participants received common stock distributions of 1,936 shares in 2006, 12,271 shares in 2005 and 46,544 shares in 2004.

Prior to the adoption of SFAS No. 123R, we reported all tax benefits resulting from the vesting of RSU awards and exercise of stock options as operating cash flows in the consolidated statements of cash flows. SFAS No. 123R requires cash retained as a result of excess tax benefits resulting from the tax deductions in excess of the related compensation cost recognized in the financial statements to be classified as cash flows from financing activities in the consolidated statements of cash flows.

13. WOLF CREEK EMPLOYEE BENEFIT PLANS

Pension and Post-retirement Benefits

As a co-owner of Wolf Creek, KGE is indirectly responsible for 47% of the liabilities and expenses associated with the Wolf Creek pension and post-retirement plans. KGE accrues its 47% of the Wolf Creek cost of pension and post-retirement benefits during the years an employee provides service. The following tables summarize the net periodic costs for KGE's 47% share of the Wolf Creek pension and post-retirement benefit plans.

	Pension Benefits		Post-retirement Benefits	
As of December 31,	2006	2005	2006	2005
	(In Thousands)			
Change in Benefit Obligation:				
Benefit obligation, beginning of year	$ 71,537	$ 59,168	$ 7,005	$ 6,102
Service cost	3,245	2,820	248	238
Interest cost	4,293	3,730	412	384
Plan participants' contributions	—	—	253	193
Benefits paid	(1,185)	(992)	(610)	(515)
Actuarial losses	1,278	6,811	83	603
Amendments	45	—	—	—
Benefit obligation, end of year	$ 79,213	$ 71,537	$ 7,391	$ 7,005
Change in Plan Assets:				
Fair value of plan assets, beginning of year	$ 39,752	$ 32,491	$ N/A	$ N/A
Actual return on plan assets	4,346	2,979	N/A	N/A
Employer contribution	4,766	5,084	N/A	N/A
Benefits paid	(995)	(802)	N/A	N/A
Fair value of plan assets, end of year	$ 47,869	$ 39,752	$ N/A	$ N/A
Funded status	$ (31,344)	$ (31,785)	$ (7,391)	$ (7,005)
Unrecognized net loss	N/A	20,850	N/A	2,645
Unrecognized transition obligation, net	N/A	342	N/A	403
Unrecognized prior service cost	N/A	188	N/A	—
Post-measurement date adjustments	1,164	205	N/A	—
Accrued post-retirement benefit costs	$ (30,180)	$ (10,200)	$ (7,391)	$ (3,957)
Amounts Recognized in the Balance Sheets Consist Of:				
Current liability	$ (190)	$ N/A	$ (347)	$ N/A
Noncurrent liability	(29,990)	N/A	(7,044)	N/A
Accrued benefit liability	N/A	(10,200)	N/A	(3,957)
Additional minimum liability	N/A	(5,144)	N/A	N/A
Intangible asset	N/A	530	N/A	N/A
Accumulated other comprehensive income	N/A	4,614	N/A	N/A
Net amount recognized	$ (30,180)	$ (10,200)	$ (7,391)	$ (3,957)
Amounts Recognized in Regulatory Assets Consist of:				
Net actuarial loss	$ 19,397	$ N/A	$ 2,531	$ N/A
Prior service cost	202	N/A	—	N/A
Transition obligation	284	N/A	346	N/A
Net amount recognized	$ 19,883	$ N/A	$ 2,877	$ N/A

	Pension Benefits		Post-retirement Benefits	
As of December 31,	2006	2005	2006	2005
	(Dollars in Thousands)			
Pension Plans With a Projected Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$ 79,213	$ 71,537	$ N/A	$ N/A
Accumulated benefit obligation	62,339	55,302	N/A	N/A
Fair value of plan assets	47,869	39,752	N/A	N/A
Pension Plans With an Accumulated Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$ 79,213	$ 71,537	$ N/A	$ N/A
Accumulated benefit obligation	62,339	55,302	N/A	N/A
Fair value of plan assets	47,869	39,752	N/A	N/A
Post-retirement Plans With an Accumulated Post-retirement Benefit Obligation In Excess of Plan Assets:				
Accumulated post-retirement benefit obligation	$ N/A	$ N/A	$ 7,931	$ 7,005
Fair value of plan assets	N/A	N/A	N/A	N/A
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Benefit Obligation:				
Discount rate	5.70%	5.75%	5.80%	5.75%
Compensation rate increase	3.25%	3.25%	N/A	N/A

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

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

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

Year Ended December 31,	Pension Benefits 2006	2005	2004
	(Dollars in Thousands)		
Components of Net Periodic Cost:			
Service cost	$ 3,245	$ 2,820	$ 2,572
Interest cost	4,293	3,730	3,295
Expected return on plan assets	(3,428)	(3,114)	(2,780)
Amortization of unrecognized:			
Transition obligation, net	57	57	57
Prior service costs	31	31	31
Actuarial loss, net	1,813	1,340	802
Net periodic cost	$ 6,011	$ 4,864	$ 3,977
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost:			
Discount rate	5.75%	6.00%	6.20%
Expected long-term return on plan assets	8.25%	8.75%	9.00%
Compensation rate increase	3.25%	3.00%	3.20%

Year Ended December 31,	Post-retirement Benefits 2006	2005	2004
	(Dollars in Thousands)		
Components of Net Periodic Cost:			
Service cost	$ 248	$ 238	$ 235
Interest cost	412	384	356
Expected return on plan assets	—	—	—
Amortization of unrecognized:			
Transition obligation, net	58	58	58
Prior service costs	—	—	—
Actuarial loss, net	196	170	141
Net periodic cost	$ 914	$ 850	$ 790
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost:			
Discount rate	5.75%	6.00%	6.10%
Expected long-term return on plan assets	N/A	N/A	N/A
Compensation rate increase	N/A	N/A	N/A

The estimated amounts that will be amortized from regulatory assets into net periodic benefit cost in 2007 are as follows:

	Pension Benefits	Other Post-retirement Benefits
Actuarial loss	$ 1,724	$ 183
Prior service cost	54	—
Transition obligation	57	58
Total	$ 1,835	$ 241

The expected long-term rate of return on plan assets is based on historical and projected rates of return for current and planned asset classes in the plans' investment portfolio. Assumed projected rates of return for each asset class were selected after analyzing long-term historical experience and future expectations of the volatility of the various asset classes. Based on target asset allocations for each asset class, the overall expected rate of return for the portfolio was developed, adjusted for historical and expected experience of active portfolio management results compared to benchmark returns and for the effect of expenses paid from plan assets.

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

As of December 31,	2006	2005
Health care cost trend rate assumed for next year	9.0%	8.0%
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	2011	2012

The health care cost trend rate affects 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	$ 6	$ (6)
Effect on the present value of the projected benefit obligation	42	(42)

The asset allocation for the pension plans at the end of 2006 and 2005, and the target allocation for 2007, by asset category are as shown in the following table.

Asset Category	Target Allocations 2007	Plan Assets 2006	2005
Pension Plans:			
Equity securities	65%	63%	63%
Debt securities	35%	34%	27%
Cash	0%	3%	10%
Total		100%	100%

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

Expected Cash Flows	Pension Benefits To/(From) Trust	To/(From) Company Assets	Post-retirement Benefits To/(From) Trust	To/(From) Company Assets
	(In Millions)			
Expected contributions:				
2007	$ 6.3	$ 0.2	$ N/A	$ 0.3
Expected benefit payments:				
2007	$(1.2)	$(0.2)	$ N/A	$(0.3)
2008	(1.5)	(0.2)	N/A	(0.4)
2009	(1.7)	(0.2)	N/A	(0.4)
2010	(2.0)	(0.2)	N/A	(0.4)
2011	(2.4)	(0.2)	N/A	(0.5)
2012 – 2016	(20.2)	(1.2)	N/A	(3.2)

Savings Plan

Wolf Creek maintains a qualified 401(k) savings plan in which most of its employees participate. They match employees' contributions in cash up to specified maximum limits. Wolf Creek's contribution to the plan is deposited with a trustee and is invested at the direction of plan participants into one or more of the investment alternatives provided under the plan. KGE's portion of expense associated with Wolf Creek's matching contributions was $0.9 million in 2006, $0.9 million in 2005 and $0.8 million in 2004.

14. 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 $352.7 million as of December 31, 2006, of which $176.1 million has been committed. The $176.1 million commitment relates to purchase obligations issued and outstanding at year-end.

The yearly detail of the aggregate amount of required payments as of December 31, 2006 was as follows.

	Committed Amount
	(In Thousands)
2007	$ 56,441
2008	99,726
2009	13,818
Thereafter	6,135
Total amount committed	$176,120

Clean Air Act

We must comply with the Clean Air Act, state laws and implementing regulations that impose, among other things, limitations on major pollutants, including sulfur dioxide (SO_2), particulate matter and nitrogen oxides (NOx). In addition, we must comply with the provisions of the Clean Air Act Amendments of 1990 that require a two-phase reduction in some emissions. We have installed continuous monitoring and reporting equipment in order to meet the acid rain requirements.

Environmental Projects

KCPL began updating or installing additional equipment related to emissions controls at La Cygne in 2005. We will continue to incur costs through the scheduled completion in 2009. We anticipate that our share of these capital costs will be approximately $232.5 million. Additionally, we have identified the potential for up to $512.4 million of expenditures at other power plants for other environmental projects during approximately the next seven to ten years. This cost could increase depending on the resolution of the Environmental Protection Agency (EPA) New Source Review described below. In addition to the capital investment, were we to install such equipment, we anticipate that we would incur significant annual expense to operate and maintain the equipment and the operation of the equipment would reduce net production from our plants. The environmental cost recovery rider (ECRR) approved in the 2005 KCC Order allows for the timely inclusion in rates of capital expenditures tied directly to environmental improvements required by the Clean Air Act. However, increased operating and maintenance costs, other than expenses related to production-related consumables, such as limestone, can be recovered only through a change in base rates following a rate review.

The degree to which we will need to reduce emissions and the timing of when such emissions controls may be required is uncertain. Both the timing and the nature of required investments depend on specific outcomes that result from interpretation of regulations, new regulations, legislation, and the resolution of the EPA New Source Review described below. In addition, the availability of equipment and contractors can affect the timing and ultimate cost of equipment installation. Whether through base rates or the ECRR, we expect to recover such costs through the rates we charge our customers.

EPA New Source Review

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

The EPA requested information from us under Section 114 regarding projects and maintenance activities that have been conducted since 1980 at 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. 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 the ECRR. 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. We are not able to estimate the possible loss or range of loss at this time.

Manufactured Gas Sites

We have been associated with a number of former manufactured gas sites located in Kansas and Missouri. We and the Kansas Department of Health and Environment (KDHE) entered into a consent agreement in 1994 governing all future work at the Kansas sites. Under the terms of the consent agreement, we agreed to investigate and, if necessary, remediate these sites. Pursuant to an environmental indemnity agreement with ONEOK, the current owner of some of the sites, our liability for twelve of the 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. We have sole responsibility for remediation with respect to three sites.

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.

Nuclear Decommissioning

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

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

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

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

Nuclear decommissioning costs that are recovered in rates are deposited in an external trust fund. We recovered in rates and deposited in the trust approximately $3.9 million for nuclear decommissioning in 2006 and 2005 and $3.8 million in 2004. We record our investment in the nuclear decommissioning fund at fair value. The fair value approximated $111.1 million as of December 31, 2006 and $100.8 million as of December 31, 2005.

Storage of Spent Nuclear Fuel

Under the Nuclear Waste Policy Act of 1982, the Department of Energy (DOE) is responsible for the permanent disposal of spent nuclear fuel. As required by federal law, the Wolf Creek co-owners entered into a standard contract with the DOE in 1984 in which the DOE promised to begin accepting from commercial nuclear power plants their used nuclear fuel for disposal beginning in early 1998. In return, Wolf Creek pays into a federal Nuclear Waste Fund administered by the DOE a quarterly fee for the future disposal of spent nuclear fuel. Our share of the fee was $4.1 million in 2006, $3.8 million in 2005 and $4.3 million in 2004 and is calculated as one-tenth of a cent for each kilowatt-hour of net nuclear generation produced. We include these disposal costs in operating expenses.

In 2002, the Yucca Mountain site in Nevada was approved for the development of a nuclear waste repository for the disposal of spent nuclear fuel and high level nuclear waste from the nation's defense activities. This action allows the DOE to apply to the NRC to license the project. Currently, the DOE has not defined a schedule for submitting a license application. The opening of the Yucca Mountain site has been delayed many times and could be delayed further due to litigation and other issues related to the site as a permanent repository for spent nuclear fuel. Wolf Creek has on-site temporary storage for spent nuclear fuel expected to be generated by Wolf Creek through 2025.

Nuclear Insurance

We maintain nuclear insurance for Wolf Creek in four areas: liability, worker radiation, property and accidental outage. These policies contain certain industry standard exclusions, including, but not limited to, ordinary wear and tear and war. Both the nuclear liability and property insurance programs subscribed to by members of the nuclear power generating industry include industry aggregate

limits for non-certified acts, as defined by the Terrorism Risk Insurance Act, of terrorism-related losses, including replacement power costs. An industry aggregate limit of $300.0 million exists for liability claims, regardless of the number of non-certified acts affecting Wolf Creek or any other nuclear energy liability policy or the number of policies in place. An industry aggregate limit of $3.2 billion plus any reinsurance recoverable by Nuclear Electric Insurance Limited (NEIL), our insurance provider, exists for property claims, including accidental outage power costs for acts of terrorism affecting Wolf Creek or any other nuclear energy facility property policy within twelve months from the date of the first act. These limits are the maximum amount to be paid to members who sustain losses or damages from these types of terrorist acts. For certified acts of terrorism, the individual policy limits apply. In addition, industry-wide retrospective assessment programs (discussed below) can apply once these insurance programs have been exhausted.

Nuclear Liability Insurance

Pursuant to the Price-Anderson Act, which was reauthorized through December 31, 2025 by the Energy Policy Act of 2005, we are required to insure against public liability claims resulting from nuclear incidents to the full limit of public liability, which is currently approximately $10.8 billion. This limit of liability consists of the maximum available commercial insurance of $300.0 million, and the remaining $10.5 billion is provided through mandatory participation in an industry-wide retrospective assessment program. Under this retrospective assessment program, the owners of Wolf Creek Nuclear Operating Corporation can be assessed a total of $100.6 million (our share is $47.3 million), payable at no more than $15.0 million (our share is $7.1 million) per incident per year, per reactor. Both the total and yearly 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. The next scheduled inflation adjustment is scheduled for July 1, 2008. In addition, Congress could impose additional revenue-raising measures to pay claims.

Nuclear Property Insurance

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

Accidental Nuclear Outage Insurance

The owners also carry additional insurance with NEIL to cover costs of replacement power and other extra expenses incurred during a prolonged outage resulting from accidental property damage at Wolf Creek. If significant losses were incurred at any of the nuclear plants insured under the NEIL policies, we may be subject to retrospective assessments under the current policies of approximately $26.1 million (our share is $12.3 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. As of December 31, 2006, our share of Wolf Creek's nuclear fuel commitments were approximately $75.4 million for uranium concentrates expiring in 2017, $10.6 million for conversion expiring in 2017, $145.6 million for enrichment expiring at various times through 2024 and $53.5 million for fabrication through 2024.

As of December 31, 2006, our coal and coal transportation contract commitments in 2006 dollars under the remaining terms of the contracts were approximately $1.4 billion. The largest contract expires in 2020, with the remaining contracts expiring at various times through 2013.

As of December 31, 2006, our natural gas transportation commitments in 2006 dollars under the remaining terms of the contracts were approximately $32.1 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 Decommissioning Fund. Our portion of the assessment, including carrying costs, for Wolf Creek was approximately $9.7 million, adjusted for inflation. We recover such costs from prices we charge our customers.

15. ASSET RETIREMENT OBLIGATIONS

Legal Liability

In accordance with SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143) and FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations" (FIN 47), we have recognized legal obligations associated with the disposal of long-lived assets that result from the acquisition, construction, development or normal operation of such assets. Concurrent with the recognition of the liability, the estimated cost of an asset retirement obligation is capitalized and depreciated over the remaining life of the asset.

We have recorded asset retirement obligations at fair value for: the estimated cost to decommission Wolf Creek (our 47% share); disposal of asbestos insulating material at our power plants; remediation of ash disposal ponds; and the disposal of polychlorinated biphenyl (PCB) contaminated oil.

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

As of December 31,	2006	2005
	(In Thousands)	
Beginning asset retirement obligations	$ 129,888	$ 87,118
Liabilities incurred	218	—
Liabilities settled	(737)	—
Transition liability	—	6,336
Accretion expense	8,327	21,796
Revision to nuclear decommissioning ARO Liability	(53,504)	14,638
Ending asset retirement obligations	$ 84,192	$ 129,888

In September 2006, Wolf Creek Nuclear Operating Corporation (WCNOC), the operating company for Wolf Creek, filed a request for a 20 year extension of Wolf Creek's operating license with the Nuclear Regulatory Commission (NRC). Currently, the operating license will expire in 2025. We anticipate that the NRC may take up to two years before it rules on the request. The NRC may impose conditions as part of any approval. Based on the experience of other nuclear plant operators, we believe that the NRC will ultimately approve the request. Therefore, we decreased our asset retirement obligation by $53.5 million to reflect the revision in our estimate of the timing of the cash flows that we will incur to satisfy this obligation.

During 2005 we updated our nuclear decommissioning and dismantlement study. Based upon the results of the 2005 study, we revised our estimate of our Wolf Creek asset retirement obligation. Accordingly, in 2005 we increased our asset retirement liability by $14.6 million.

In March 2005, the FASB issued FIN 47. The interpretation clarified the term "conditional asset retirement obligation" as used in SFAS No. 143. Conditional asset retirement obligation refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. We determined the conditional asset retirement obligations that are within the scope of FIN 47 to include disposal of asbestos insulating material at our power plants, remediation of ash disposal ponds and the disposal of PCB contaminated oil. We adopted the provisions of FIN 47 for the year ended December 31, 2005.

The amount of the retirement obligation related to asbestos disposal was recorded as of 1990, the date when the Environmental Protection Agency published the "National Emission Standards for Hazardous Air Pollutants: Asbestos NESHAP Revision; Final Rule."

We operate, as permitted by the state of Kansas, ash landfills at several of our power plants. The ash landfills retirement obligation was determined based upon the date each landfill was originally placed in service.

PCB contaminates are contained within company electrical equipment, primarily transformers. The PCB contaminates retirement obligation was determined based upon the PCB regulations that originally became effective in 1978.

The recording of the obligation for regulated operations has no income statement impact due to the deferral of the adjustments through the establishment of a regulatory asset pursuant to SFAS No. 71. The following table summarizes the accounting for the initial adoption of FIN 47, as of December 31, 2005.

	Plant Assets	Regulatory Assets	Long-Term Liabilities
		(In Thousands)	
Reflect retirement obligation when liability incurred	$ 6,336	$ —	$ 6,336
Record accretion of liability to adoption date	—	14,861	14,861
Record depreciation of plant to adoption date	(3,825)	3,825	–
Net impact of FIN 47	$ 2,511	$ 18,686	$ 21,197

Non-Legal Liability — Cost of Removal

We recover in rates, as a component of depreciation, the costs to dispose of utility plant assets that do not represent legal retirement obligations. As of December 31, 2006 and 2005, we had $13.4 million and $6.9 million, respectively, in amounts collected, but unspent, for removal costs classified as a regulatory liability. The net amount related to non-legal retirement costs can fluctuate based on amounts recovered in rates compared to removal costs incurred.

16. LEGAL PROCEEDINGS

We and certain of our present and former officers and directors were 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. In early April 2005, we reached an agreement in principle with the plaintiffs to settle this lawsuit for $30.0 million. The full terms of the proposed settlement are set forth in a Stipulation and Agreement of Compromise, Settlement and Release dated as of May 31, 2005 filed with the court. On September 1, 2005, the court approved the proposed settlement and directed the parties to consummate the settlement in accordance with the stipulation. Pursuant to the stipulation, we paid $1.25 million and our insurance carriers paid $28.75 million into a settlement fund that following effectiveness of the settlement was disbursed, after payment of $9.0 million of legal fees for plaintiffs' counsel plus expenses, to shareholders as provided in the stipulation. The amounts paid by our insurance carriers in this settlement included the payments related to the settlement of the shareholder derivative lawsuit described below. The settlement became effective on June 21, 2006.

Certain present and former members of our board of directors and officers were 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." In early April 2005, a special litigation committee of our board of directors approved an agreement in principle to settle this lawsuit for $12.5 million to be paid to us by our insurance carriers. The full terms of the proposed settlement are set forth in a Stipulation and Agreement of Compromise, Settlement and Release dated May 31, 2005 filed with the court. On September 1, 2005, the court approved the proposed settlement and directed the parties to consummate the settlement in accordance with the stipulation. Pursuant to the stipulation, the recovery from our insurance carriers, less attorney's fees of $2.5 million, was paid into the settlement fund for the settlement of the securities class action lawsuit as described above. On September 16, 2005, one shareholder filed a motion asking the court to reconsider its order approving the settlement. The court denied this motion on December 2, 2005, and the shareholder then filed a timely appeal with the United States Court of Appeals for the Tenth Circuit. This appeal was dismissed on June 21, 2006 and the settlement became effective.

We and certain of our present and former officers and employees were 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." The lawsuit was brought on behalf of participants in, and beneficiaries of, our Employees' 401(k) Savings Plan between July 1, 1998 and January 1, 2003. On January 31, 2006, we reached an agreement in principle with the plaintiffs to settle this lawsuit for $9.25 million to be paid by our insurance carrier. The full terms of the proposed settlement are set forth in a Class Action Settlement Agreement dated March 23, 2006 filed with the court. On July 27, 2006, the court issued an order that approved the proposed settlement, approved plaintiffs' attorneys' fees and litigation expenses totaling $2.9 million to be paid from the settlement fund, and directed the parties to consummate the settlement in accordance with the settlement agreement.

After the settlement of these lawsuits became effective in 2006, settlement funds were disbursed and liabilities previously recorded in connection with these settlements as current liabilities were reflected as having been paid.

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 final resolution of the criminal charges filed by the United States Attorney's Office against Mr. Wittig and Mr. Lake in U.S. District Court in the District of Kansas. On September 12, 2005, the jury convicted Mr. Wittig and Mr. Lake on the charges relevant to each of them. On January 5, 2007, these convictions were overturned by U.S. Tenth Circuit Court of Appeals following appeals by Mr. Wittig and Mr. Lake. The government is evaluating what action to take as a result of this decision and the arbitration remains stayed. We are unable to predict the ultimate impact of this matter on our consolidated results of operations.

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 results of operations.

See also Notes 14, 17 and 18 for discussion of 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.

17. 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. Subsequently, the United States Attorney's Office 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 provided information in response to these requests and we cooperated 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. For additional information regarding the jury trial of Mr. Wittig and Mr. Lake, see Note 18, "Potential Liabilities to David C. Wittig and Douglas T. Lake."

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 pension benefit plan. We have provided information to the Department of Labor pursuant to the subpoena and subsequent inquiries. 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 16, "Legal Proceedings," for discussion of a class action lawsuit brought on behalf of participants in our Employees' 401(k) Savings Plan.

18. 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. 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 final resolution of criminal charges filed by the United States Attorney's Office against Mr. Wittig and Mr. Lake in U.S. District Court in the District of Kansas. On September 12, 2005, the jury convicted Mr. Wittig and Mr. Lake on the charges relevant to each of them. On January 5, 2007, these convictions were overturned by U.S. Tenth Circuit Court of Appeals following appeals by Mr. Wittig and Mr. Lake. The government is evaluating what action to take as a result of this decision and the arbitration remains stayed. We are unable to predict the ultimate impact of this matter on our consolidated results of operations.

As of December 31, 2006, we had accrued liabilities totaling approximately $74.8 million for compensation not yet paid to Mr. Wittig and Mr. Lake under various agreements and plans. The compensation includes RSU awards, deferred vested shares, deferred RSU awards, deferred vested stock for compensation, executive salary continuation plan benefits, potential obligations related to the cash received for Guardian International, Inc. (Guardian) preferred stock as discussed in Note 19, "Guardian International Preferred Stock," 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, through December 31, 2006 we have accrued $9.9 million for legal fees and expenses incurred by Mr. Wittig and Mr. Lake that are recorded in accounts payable on our consolidated balance sheets. These legal fees and expenses were incurred by Mr. Wittig and Mr. Lake in the defense of the criminal charges filed by the United States Attorney's Office and the subsequent appeal of convictions on these charges. On January 5, 2007, the convictions were overturned by the U.S. Tenth Circuit Court of Appeals. We may incur substantial additional expenses for legal fees and expenses incurred by Mr. Wittig and Mr. Lake depending on the actions taken by the United States Attorney's Office as a result of the decision by the Tenth Circuit Court of Appeals and developments in the arbitration, neither of which we are able to predict at this time. We have filed lawsuits against Mr. Wittig and Mr. Lake claiming that the legal fees and expenses they have incurred, which we have advanced or for which they seek advancement in the defense of the criminal charges, are unreasonable and excessive. We have asked the court to determine the amount of the legal fees and expenses that were reasonably incurred and which we have an obligation to advance. We are unable to estimate the amount of the legal fees and expenses that will be incurred by Mr. Wittig and Mr. Lake for which we may be ultimately responsible.

The jury in the trial of Mr. Wittig and Mr. Lake also determined that Mr. Wittig and Mr. Lake should forfeit to the United States certain property that it determined was derived from their criminal conduct. We subsequently filed petitions asserting a superior interest in certain forfeited property. The court subsequently entered final orders of forfeiture awarding us certain property forfeited by Mr. Wittig and Mr. Lake. The property awarded to us consists substantially of compensation and benefits that we were seeking to avoid paying in the arbitration proceeding referenced above. Following appeal, the Tenth Circuit Court of Appeals also overturned the forfeiture orders.

19. GUARDIAN INTERNATIONAL PREFERRED STOCK

On March 6, 2006, Guardian was acquired by Devcon International Corporation in a merger. In connection with this merger, we received approximately $23.2 million for 15,214 shares of Guardian Series D preferred stock and 8,000 shares of Guardian Series E preferred stock held of record by us. We beneficially owned 354.4 shares of the Guardian Series D preferred stock and 312.9 shares of the Guardian Series E preferred stock. We recognized a gain of approximately $0.3 million as a result of this transaction. Certain current and former officers beneficially owned the remaining shares. Of these shares, 14,094 shares of Guardian Series D preferred stock and 7,276 shares of Guardian Series E preferred stock were beneficially owned by Mr. Wittig and Mr. Lake. The ownership of the shares beneficially owned by either Mr. Wittig or Mr. Lake, as well as related dividends, and now the cash received for the shares, is disputed and is the subject of the arbitration proceeding with Mr. Wittig and Mr. Lake discussed in Note 16, "Legal Proceedings." These shares were, and now the cash received for the shares are, also part of the property forfeited by Mr. Wittig and Mr. Lake in the criminal proceeding discussed in Note 18, "Potential Liabilities to David C. Wittig and Douglas T. Lake." As a result of this transaction, we no longer hold any Guardian securities.

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 16, "Legal Proceedings."

20. COMMON AND PREFERRED STOCK

Activity in Westar Energy's stock accounts for each of the three years ended December 31 is as follows:

	Cumulative preferred stock shares	Common stock shares	Treasury stock shares
Balance at December 31, 2003	214,363	72,840,217	(203,575)
Issuance of common stock	—	13,189,504	—
Issuance of treasury stock	—	—	203,575
Balance at December 31, 2004	214,363	86,029,721	—
Issuance of common stock	—	805,650	—
Balance at December 31, 2005	214,363	86,835,371	—
Issuance of common stock	—	559,515	—
Balance at December 31, 2006	214,363	87,394,886	—

Westar Energy's articles of incorporation, as amended, provide for 150,000,000 authorized shares of common stock. As of December 31, 2006, we had 87,394,886 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 2006, a total of 559,515 shares were issued by Westar Energy through the DSPP and other stock based plans operated under the 1996 Long-Term Incentive and Share Award Plan. As of December 31, 2006, a total of 4,684,639 shares were available under the DSPP registration statement.

Common Stock Issuance

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

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 as of December 31, 2006.

Rate	Shares	Principal Outstanding	Call Price	Premium	Total Cost 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 its 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 Westar Energy's common stock, including premiums on its 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 its common stock shall not exceed 50% of its 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 its common 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. As of December 31, 2006, 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 its outstanding common stock and its 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.

21. LEASES

Operating Leases

We lease office buildings, computer equipment, vehicles, rail cars, a generating facility and other property and equipment. These leases have various terms and expiration dates ranging from 1 to 23 years.

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

Year Ended December 31,	La Cygne Unit 2 Lease[a]	Total Operating Leases
	(In Thousands)	
Rental expense:		
2004	$ 28,895	$ 38,793
2005	23,481	34,239
2006	18,069	32,107
Future commitments:		
2007	$ 23,464	$ 35,272
2008	32,892	45,196
2009	32,964	43,868
2010	33,041	42,622
2011	33,122	42,366
Thereafter	322,683	374,415
Total future commitments	$478,166	$583,739

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

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

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

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 4-year term. Assets recorded under capital leases are listed below.

December 31,	2006	2005
	(In Thousands)	
Vehicles	$30,009	$33,518
Computer equipment and software	4,950	4,168
Accumulated amortization	(18,115)	(19,375)
Total capital leases	$16,844	$18,311

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 are listed below.

Year Ended December 31,	Total Capital Leases
	(In Thousands)
2007	$ 6,162
2008	4,593
2009	3,617
2010	2,425
2011	2,420
Thereafter	2,562
	21,779
Amounts representing imputed interest	(4,935)
Present value of net minimum lease payments under capital leases	$16,844

22. DISCONTINUED OPERATIONS — Sale of Protection One and Protection One Europe

In 2006, we received proceeds of $1.2 million that was released from an escrow account arising from the sale of Protection One Europe, a security business we sold on June 30, 2003. In 2005, we recorded approximately $0.7 million in income in our results of discontinued operations due to the resolution of indemnification issues with the sale of the Protection One Europe security business.

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.

Results of discontinued operations are presented in the table below.

Year Ended December 31,	2005[a]	2004[b]
	(In Thousands, Except Per Share Amounts)	
Sales	$ —	$ 22,466
Costs and expenses	—	19,937
Earnings from discontinued operations before income taxes	—	2,529
Estimated gain on disposal	1,232	30,980
Income tax expense (benefit)	490	(45,281)
Results of discontinued operations	$ 742	$ 78,790
Basic results of discontinued operations per share	$ 0.01	$ 0.95
Diluted results of discontinued operations per share	$ 0.01	$ 0.94

[a] *Amounts are related to the resolution of indemnification issues associated with the sale of Protection One Europe.*

[b] *Includes results through February 17, 2004 when Protection One was sold.*

23. 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.

Recognition of the change in the market value of our fuel contracts significantly affected our 2005 quarterly results. Based on the terms of certain fuel supply contracts, changes in the fair value of these contracts were marked-to-market through earnings in accordance with the requirements of SFAS No. 133. We recognized non-cash gains of $12.3 million for the three months ended March 31, 2005, $13.0 million for the three months ended June 30, 2005 and $45.8 million for the three months ended September 30, 2005. As a result of the December 28, 2005 KCC Order implementing the RECA, we reversed $70.9 million of these previously recognized mark-to-market adjustments to fuel expense during the fourth quarter of 2005.

Also as a result of the December 28, 2005 KCC Order, during the fourth quarter of 2005 we recorded a $10.4 million write-off of disallowed plant costs and established a regulatory asset for depreciation differences, which allowed us to record a reduction in depreciation expense of $20.1 million.

In addition, our net results of discontinued operations varied between comparable quarters. In the fourth quarter of 2005, we recognized income from discontinued operations of $0.7 million, which reflects the resolution of indemnification issues with the sale of the Protection One Europe security business.

2006	First	Second	Third	Fourth
	(In Thousands, Except Per Share Amounts)			
Sales	$340,023	$406,622	$515,947	$343,152
Net income	26,838	35,365	90,034	13,073
Earnings available for common stock	$ 26,596	$ 35,123	$ 89,792	$ 12,831
Per Share Data[a]:				
Basic:				
Earnings available	$ 0.30	$ 0.40	$ 1.03	$ 0.15
Diluted:				
Earnings available	$ 0.30	$ 0.40	$ 1.02	$ 0.15
Cash dividend declared per common share	$ 0.25	$ 0.25	$ 0.25	$ 0.25
Market price per common share:				
High	$ 22.05	$ 22.39	$ 24.60	$ 27.24
Low	$ 20.09	$ 20.40	$ 21.50	$ 23.20

[a] *Items are computed independently for each of the periods presented and the sum of the quarterly amounts may not equal the total for the year.*

2005	First	Second	Third	Fourth
	(In Thousands, Except Per Share Amounts)			
Sales	$336,502	$374,802	$477,896	$394,078
Income from continuing operations	15,615	27,876	84,475	6,901
Results of discontinued operations, net of tax	—	—	—	742
Net income	15,615	27,876	84,475	7,643
Earnings available for common stock	$ 15,373	$ 27,634	$ 84,233	$ 7,401
Per Share Data[a]:				
Basic:				
Earnings available from continuing operations	$ 0.18	$ 0.32	$ 0.97	$ 0.07
Discontinued operations, net of tax	—	—	—	0.01
Earnings available	$ 0.18	$ 0.32	$ 0.97	$ 0.08
Diluted:				
Earnings available from continuing operations	$ 0.18	$ 0.32	$ 0.96	$ 0.07
Discontinued operations, net of tax	—	—	—	0.01
Earnings available	$ 0.18	$ 0.32	$ 0.96	$ 0.08
Cash dividend declared per common share	$ 0.23	$ 0.23	$ 0.23	$ 0.23
Market price per common share:				
High	$ 23.80	$ 24.29	$ 24.97	$ 24.80
Low	$ 21.07	$ 21.10	$ 22.90	$ 21.26

[a] *Items are computed independently for each of the periods presented and the sum of the quarterly amounts may not equal the total for the year.*

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, as of December 31, 2006, 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 accumulated and communicated to the chief executive officer and the chief financial officer, and 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, 2006, 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 2007 Annual Meeting of Shareholders to be filed pursuant to Regulation 14A (the 2007 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 2007 Proxy Statement, and that information is incorporated by reference in this Form 10-K. The information required by Item 406, 407(c)(3), (d)(4) and (d)(5) of Regulation S-K will be included under the caption "Corporate Governance Matters" in our 2007 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 2007 Proxy Statement under the captions "Compensation Discussion and Analysis," "Compensation Committee Report," "Compensation of Executive Officers and Directors," and "Compensation Committee Interlocks and Insider Participation" 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 2007 Proxy Statement under the captions "Beneficial Ownership of Voting Securities" and "Shares Authorized For Issuance Under Equity Compensation Plans," 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 2007 Proxy Statement under the captions "Independent Registered Accounting Firm 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.

Management's Report on Internal Control Over Financial Reporting

Reports of Independent Registered Public Accounting Firm

Consolidated Balance Sheets, as of December 31, 2006 and 2005

Consolidated Statements of Income for the years ended December 31, 2006, 2005 and 2004

Consolidated Statements of Comprehensive Income for the years ended December 31, 2006, 2005 and 2004

Consolidated Statements of Cash Flows for the years ended December 31, 2006, 2005 and 2004

Consolidated Statements of Shareholders' Equity for the years ended December 31, 2006, 2005 and 2004

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 15(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 Form 8-K filed on January 18, 2005)	I
1(b)	— Underwriting Agreement between Westar Energy, Inc. and Barclays Capital and Citigroup Global Markets, Inc., as representatives of the several underwriters, dated June 27, 2005 (filed as Exhibit 1.1 to the Form 8-K filed on July 1, 2005)	I
3(a)	— By-laws of Westar Energy, Inc., as amended April 28, 2004 (filed as Exhibit 3(a) to the Form 10-Q for the period ended June 30, 2004 filed on August 4, 2004)	I
3(b)	— Restated Articles of Incorporation of Westar Energy, Inc., as amended through May 25, 1988 (filed as Exhibit 4 to the Form S-8 Registration Statement, SEC File No. 33-23022 filed on July 15, 1988)	I
3(c)	— Certificate of Amendment to Restated Articles of Incorporation of Westar Energy, Inc. (filed as Exhibit 3 to the Form 10-K405 for the period ended December 31, 1998 filed on April 14, 1999)	I
3(d)	— Certificate of Designations for Preference Stock, 8.5% Series (filed as Exhibit 3(d) to the Form 10-K for the period ended December 31, 1993 filed on March 22, 1994)	I
3(e)	— Certificate of Correction to Restated Articles of Incorporation of Westar Energy, Inc. (filed as Exhibit 3(b) to the Form 10-K for the period ended December 31, 1991 filed on March 30, 1992)	I
3(f)	— Certificate of Designations for Preference Stock, 7.58% Series (filed as Exhibit 3(e) to the Form 10-K for the period ended December 31, 1993 filed on March 22, 1994)	I
3(g)	— Certificate of Amendment to Restated Articles of Incorporation of Westar Energy, Inc. (filed as Exhibit 3(c) to the Form 10-K for the period ended December 31, 1994 filed on March 30, 1995)	I
3(h)	— Certificate of Amendment to Restated Articles of Incorporation of Westar Energy, Inc. (filed as Exhibit 3 to the Form 10-Q for the period ended June 30, 1994 filed on August 11, 1994)	I

3(i)	— Certificate of Amendment to Restated Articles of Incorporation of Westar Energy, Inc. (filed as Exhibit 3(a) to the Form 10-Q for the period ended June 30, 1996 filed on August 14, 1996)	I
3(j)	— Certificate of Amendment to Restated Articles of Incorporation of Westar Energy, Inc. (filed as Exhibit 3 to the Form 10-Q for the period ended March 31, 1998 filed on May 12, 1998)	I
3(k)	— Form of Certificate of Designations for 7.5% Convertible Preference Stock (filed as Exhibit 99.4 to the Form 8-K filed on November 17, 2000)	I
3(l)	— Certificate of Amendment to Restated Articles of Incorporation of Westar Energy, Inc. (filed as Exhibit 3(l) to the Form 10-K for the period ended December 31, 2002 filed on April 11, 2003)	I
3(m)	— Certificate of Amendment to Restated Articles of Incorporation of Westar Energy, Inc. (filed as Exhibit 3(m) to the Form 10-K for the period ended December 31, 2002 filed on April 11, 2003)	I
3(n)	— Certificate of Amendment to Restated Articles of Incorporation of Westar Energy, Inc. (filed as Exhibit 3(m) to the Form S-3 Registration Statement No. 333-125828 filed on June 15, 2005)	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 Form 10-K for the period ended December 31, 1992 filed on March 30, 1993)	I
4(f)	— Twenty-Ninth Supplemental Indenture dated August 20, 1992 (filed as Exhibit 4(p) to the Form 10-K for the period ended December 31, 1992 filed on March 30, 1993)	I
4(g)	— Thirtieth Supplemental Indenture dated February 1, 1993 (filed as Exhibit 4(q) to the Form 10-K for the period ended December 31, 1992 filed on March 30, 1993)	I
4(h)	— Thirty-First Supplemental Indenture dated April 15, 1993 (filed as Exhibit 4(r) to the Form S-3 Registration Statement No. 33-50069 filed on August 24, 1993)	I
4(i)	— Thirty-Second Supplemental Indenture dated April 15, 1994 (filed as Exhibit 4(s) to the Form 10-K for the period ended December 31, 1994 filed on March 30, 1995)	I
4(j)	— Thirty-Fourth Supplemental Indenture dated June 28, 2000 (filed as Exhibit 4(v) to the Form 10-K for the period ended December 31, 2000 filed on April 2, 2001)	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 Form 10-Q for the period ended March 31, 2002 filed on May 15, 2002)	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 Form 8-K filed on January 18, 2005)	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 Form 8-K filed on January 18, 2005)	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 Form 8-K filed on January 18, 2005)	I

4(o)	— Thirty-Ninth Supplemental Indenture dated June 30, 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 4.1 to the Form 8-K filed on July 1, 2005)	I
4(p)	— 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 Form 10-Q for the period ended June 30, 2002 filed on August 14, 2002)	I
4(q)	— Forty-Second Supplemental Indenture dated March 12, 2004 between Kansas Gas and Electric Company and BNY Midwest Trust Company, as Trustee (filed as Exhibit 4(p) to the Form 10-K for the period ended December 31, 2004 filed on March 16, 2005)	I
4(r)	— Forty-Fourth Supplemental Indenture dated May 6, 2005 between Kansas Gas and Electric Company and BNY Midwest Trust Company, as Trustee (filed as Exhibit 4 to the Form 10-Q for the period ended March 31, 2005 filed on May 10, 2005)	I
4(s)	— Debt Securities Indenture dated August 1, 1998 (filed as Exhibit 4.1 to the Form 10-Q for the period ended June 30, 1998 filed on August 12, 1998)	I
4(t)	— 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 Form 10-Q for the period ended March 31, 2002 filed on May 15, 2002)	I
4(u)	— Forty-Fifth Supplemental Indenture dated March 17, 2006 between Kansas Gas and Electric Company and BNY Midwest Trust Company, as Trustee, to the Kansas Gas and Electric Company Mortgage and Deed of Trust dated April 1, 1940 (filed as Exhibit 4.1 to the Form 8-K filed on March 21, 2006)	I
4(v)	— Forty-Sixth Supplemental Indenture dated June 1, 2006 between Kansas Gas and Electric Company and BNY Midwest Trust Company, as Trustee, to the Kansas Gas and Electric Company Mortgage and Deed of Trust dated April 1, 1940 (filed as Exhibit 4 to the Form 10-Q for the period ended June 30, 2006 filed on August 9, 2006)	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 Form 10-Q for the period ended June 30, 1996 filed on August 14, 1996)*	I
10(b)	— Form of Employment Agreements with Messrs. Grennan, Koupal, Terrill, Lake and Wittig and Ms. Sharpe (filed as Exhibit 10(b) to the Form 10-K for the period ended December 31, 2000 filed on April 2, 2001)*	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 Form 10-Q for the period ended June 30, 1994 filed on August 11, 1994)	I
10(d)	— Agreement between Westar Energy, Inc. and AMAX Coal West Inc. effective March 31, 1993 (filed as Exhibit 10(a) to the Form 10-K for the period ended December 31, 1993 filed on March 22, 1994)	I
10(e)	— Agreement between Westar Energy, Inc. and Williams Natural Gas Company dated October 1, 1993 (filed as Exhibit 10(b) to the Form 10-K for the period ended December 31, 1993 filed on March 22, 1994)	I
10(f)	— Short-term Incentive Plan (filed as Exhibit 10(j) to the Form 10-K for the period ended December 31, 1993 filed on March 22, 1994)*	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 10.1 to the Form 8-K filed on October 21, 2004)*	I
10(h)	— Executive Salary Continuation Plan of Western Resources, Inc., as revised, effective September 22, 1995 (filed as Exhibit 10(j) to the Form 10-K for the period ended December 31, 1995 filed on March 27, 1996)*	I
10(i)	— Letter Agreement between Westar Energy, Inc. and David C. Wittig, dated April 27, 1995 (filed as Exhibit 10(m) to the Form 10-K for the period ended December 31, 1995 filed on March 27, 1996)*	I

10(j) — Form of Split Dollar Insurance Agreement (filed as Exhibit 10.3 to the Form 10-Q for the period ended June 30, 1998 filed on August 12, 1998)* 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 Form 10-Q/A for the period ended June 30, 1998 filed on August 24, 1998)* I

10(l) — Letter Agreement between Westar Energy, Inc. and Douglas T. Lake, dated August 17, 1998 (filed as Exhibit 10(n) to the Form 10-K405 for the period ended December 31, 1999 filed on March 29, 2000)* I

10(m) — Form of Change of Control Agreement with officers of Westar Energy, Inc. (filed as Exhibit 10(o) to the Form 10-K for the period ended December 31, 2000 filed on April 2, 2001)* I

10(n) — Form of loan agreement with officers of Westar Energy, Inc. (filed as Exhibit 10(r) to the Form 10-K for the period ended December 31, 2001 filed on April 1, 2002)* 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 Form 10-Q for the period ended June 30, 2002 filed on August 14, 2002)* 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 Form 10-Q for the period ended June 30, 2002 filed on August 14, 2002)* 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 Form 10-Q for the period ended June 30, 2002 filed on August 14, 2002) I

10(r) — Employment Agreement dated September 23, 2002 between Westar Energy, Inc. and David C. Wittig (filed as Exhibit 10.1 to the Form 10-Q for the period ended September 30, 2002 filed on November 15, 2002)* I

10(s) — Employment Agreement dated September 23, 2002 between Westar Energy, Inc. and Douglas T. Lake (filed as Exhibit 10.1 to the Form 8-K filed on November 25, 2002)* 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 Form 10-Q for the period ended September 30, 2003 filed on November 10, 2003)* I

10(u) — Letter Agreement dated November 1, 2003 between Westar Energy, Inc. and William B. Moore (filed as Exhibit 10(b) to the Form 10-Q for the period ended September 30, 2003 filed on November 10, 2003)* I

10(v) — Letter Agreement dated November 1, 2003 between Westar Energy, Inc. and Mark A. Ruelle (filed as Exhibit 10(c) to the Form 10-Q for the period ended September 30, 2003 filed on November 10, 2003)* I

10(w) — Letter Agreement dated November 1, 2003 between Westar Energy, Inc. and Douglas R. Sterbenz (filed as Exhibit 10(d) to the Form 10-Q for the period ended September 30, 2003 filed on November 10, 2003)* I

10(x) — Letter Agreement dated November 1, 2003 between Westar Energy, Inc. and Larry D. Irick (filed as Exhibit 10(e) to the Form 10-Q for the period ended September 30, 2003 filed on November 10, 2003)* 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 Form 10-Q for the period ended September 30, 2003 filed on November 10, 2003) 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 Form 10-Q for the period ended March 31, 2004 filed on May 10, 2004) 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 Form 10-Q for the period ended June 30, 2004 filed on August 4, 2004) 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 Form 8-K filed on December 24, 2003)	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 Form 8-K filed on November 15, 2004)	I
10(ad)	— Restricted Share Unit Award Agreement between Westar Energy, Inc. and James S. Haines, Jr. (filed as Exhibit 10.1 to the Form 8-K filed on December 7, 2004)*	I
10(ae)	— Deferral Election Form of James S. Haines, Jr. (filed as Exhibit 10.2 to the Form 8-K filed on December 7, 2004)*	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 10.1 to the Form 8-K filed on December 17, 2004)*	I
10(ag)	— Restricted Share Unit Award Agreement between Westar Energy, Inc. and William B. Moore (filed as Exhibit 10.1 to the Form 8-K filed on December 29, 2004)*	I
10(ah)	— Deferral Election Form of William B. Moore (filed as Exhibit 10.2 to the Form 8-K filed on December 29, 2004)*	I
10(ai)	— Amended and Restated Credit Agreement dated as of May 6, 2005 among Westar Energy, Inc., the several banks and other financial institutions or entities from time to time parties to the Agreement, JPMorgan Chase Bank, N.A., 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 to the Form 10-Q for the period ended March 31, 2005 filed on May 10, 2005)	I
10(aj)	— Amended and Restated Westar Energy Restricted Share Units Deferral Election Form for James S. Haines, Jr. (filed as Exhibit 10.1 to the Form 8-K filed on December 22, 2005)*	I
10(ak)	— Form of Change in Control Agreement (filed as Exhibit 10.1 to the Form 8-K filed on January 26, 2006)*	I
10(al)	— Form of Amendment to the Employment Letter Agreements for Mr. Ruelle and Mr. Sterbenz (filed as Exhibit 10.2 to the Form 8-K filed on January 26, 2006)*	I
10(am)	— Form of Amendment to the Employment Letter Agreements for Mr. Irick and One Other Officer (filed as Exhibit 10.3 to the Form 8-K filed on January 26, 2006)*	I
10(an)	— Second Amended and Restated Credit Agreement, dated as of March 17, 2006, among Westar Energy, Inc., the several banks and other financial institutions or entities from time to time parties to the Agreement (filed as Exhibit 10.1 to the Form 8-K filed on March 21, 2006)	I
10(ao)	— Amendment to the Employment Letter Agreement for Mr. James S. Haines, Jr. (filed as Exhibit 99.3 to the Form 8-K filed on August 22, 2006)*	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 Form 10-Q for the period ended September 30, 2002 filed on November 15, 2002)	I
99(b)	— Kansas Corporation Commission Order dated December 23, 2002 (filed as Exhibit 99.1 to the Form 8-K filed on December 27, 2002)	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 Form 8-K filed on February 6, 2003)	I
99(d)	— Kansas Corporation Commission Order dated February 10, 2003 (filed as Exhibit 99.1 to the Form 8-K filed on February 11, 2003)	I

99(e) — Kansas Corporation Commission Order dated March 11, 2003 (filed as Exhibit 99(f) to the Form 10-K for the period ended December 31, 2002 filed on April 11, 2003) I

99(f) — Demand for Arbitration (filed as Exhibit 99.1 to the Form 8-K filed on June 13, 2003) I

99(g) — Stipulation and Agreement filed with the Kansas Corporation Commission on July 21, 2003 (filed as Exhibit 99.1 to the Form 8-K filed on July 22, 2003) I

99(h) — Summary of Rate Application dated May 2, 2005 (filed as Exhibit 99.1 to the Form 8-KA filed on May 10, 2005) I

99(i) — Federal Energy Regulatory Commission Order On Proposed Mitigation Measures, Tariff Revisions, and Compliance Filings issued September 6, 2006 (filed as Exhibit 99.1 to the Form 8-K filed on September 12, 2006) I

WESTAR ENERGY, INC.

SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS

Description	Balance at Beginning of Period	Charged to Costs and Expenses	Deductions[a]	Balance at End of Period
		(In Thousands)		
Year ended December 31, 2004				
Allowances deducted from assets for doubtful accounts	$5,415	$2,718	$(2,820)	$5,313
Year ended December 31, 2005				
Allowances deducted from assets for doubtful accounts	$5,313	$3,959	$(4,039)	$5,233
Year ended December 31, 2006				
Allowances deducted from assets for doubtful accounts	$5,233	$5,091	$(4,067)	$6,257

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

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 1, 2007

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 and Chief Executive Officer (Principal Executive Officer)	March 1, 2007
/s/ MARK A. RUELLE (Mark A. Ruelle)	Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	March 1, 2007
/s/ CHARLES Q. CHANDLER IV (Charles Q. Chandler IV)	Chairman of the Board	March 1, 2007
/s/ MOLLIE H. CARTER (Mollie H. Carter)	Director	March 1, 2007
/s/ R. A. EDWARDS III (R. A. Edwards III)	Director	March 1, 2007
/s/ JERRY B. FARLEY (Jerry B. Farley)	Director	March 1, 2007
/s/ B. ANTHONY ISAAC (B. Anthony Isaac)	Director	March 1, 2007
/s/ ARTHUR B. KRAUSE (Arthur B. Krause)	Director	March 1, 2007
/s/ SANDRA A. J. LAWRENCE (Sandra A. J. Lawrence)	Director	March 1, 2007
/s/ MICHAEL F. MORRISSEY (Michael F. Morrissey)	Director	March 1, 2007
/s/ JOHN C. NETTELS, JR. (John C. Nettels, Jr.)	Director	March 1, 2007

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 certificate 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.WestarEnergy.com.** Registered shareholders can easily access their shareholder account information online by clicking on the **Go to Shareholder Sign-in button.**

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

shareholders@WestarEnergy.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) 575-8227

ADDRESS

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

E-MAIL ADDRESS: ir@WestarEnergy.com

Copies of our Annual Report on Form 10-K 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.WestarEnergy.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.WestarEnergy.com

COMMON STOCK LISTING

Ticker Symbol (NYSE): WR

Daily Stock Table Listing: WestarEngy

CHIEF EXECUTIVE OFFICER AND CHIEF FINANCIAL OFFICER CERTIFICATIONS

In 2006, 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, 2006 were included as exhibits to Westar Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2006 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 B. Anthony Isaac, James S. Haines Jr., Arthur B. Krause, Sandra A.J. Lawrence, John C. Nettels Jr., R.A. Edwards III, Mollie Hale Carter, Michael F. Morrissey, Charles Q. Chandler IV and Jerry B. Farley.

CHARLES Q. CHANDLER IV (53)
Chairman of the Board
Director since 1999
Chairman since 2002
Chairman of the Board, President and Chief Executive Officer
INTRUST Bank, NA
Wichita, Kansas

MOLLIE HALE CARTER (44)
Director since 2003
Chairman of the Board, President and Chief Executive Officer
Sunflower Banks, Inc.
Salina, Kansas
Committees: Compensation, Finance

R.A. EDWARDS III (61)
Director since 2001
Director, President and Chief Executive Officer
First National Bank of Hutchinson
Hutchinson, Kansas
Committees: Audit, Nominating and Corporate Governance

JERRY B. FARLEY (60)
Director since 2004
President
Washburn University
Topeka, Kansas
Committees: Audit, Nominating and Corporate Governance

JAMES S. HAINES, JR. (60)
Director since 2002
Chief Executive Officer
Westar Energy, Inc.
Topeka, Kansas

B. ANTHONY ISAAC (53)
Director since 2003
President
LodgeWorks, Corp.
Wichita, Kansas
Committees: Compensation, Finance

ARTHUR B. KRAUSE (65)
Director since 2003
Executive Vice President and Chief Financial Officer (Retired)
Sprint Corporation
Naples, Florida
Committees: Audit, Finance

SANDRA A.J. LAWRENCE (49)
Director since 2004
Executive Vice President and Chief Financial Officer
Children's Mercy Hospital
Kansas City, Missouri
Committees: Compensation, Nominating and Corporate Governance

MICHAEL F. MORRISSEY (64)
Director since 2003
Managing Partner (Retired)
Ernst & Young LLP
Naples, Florida
Committees: Audit, Compensation

JOHN C. NETTELS, JR. (50)
Director since 2000
Partner
Stinson Morrison Hecker LLP
Overland Park, Kansas
Committee: Finance

Officers:

JAMES S. HAINES, JR. (60)
20 years of service
Chief Executive Officer

WILLIAM B. MOORE (54)
26 years of service
President and Chief Operating Officer

MARK A. RUELLE (45)
14 years of service
Executive Vice President and Chief Financial Officer

DOUGLAS R. STERBENZ (43)
9 years of service
Executive Vice President, Generation and Marketing

BRUCE A. AKIN (42)
19 years of service
Vice President, Administrative Services

GREG A. GREENWOOD (41)
13 years of service
Vice President, Generation Construction

KELLY B. HARRISON (48)
25 years of service
Vice President, Transmission Operations and Environmental Services

LARRY D. IRICK (50)
7 years of service
Vice President, General Counsel and Corporate Secretary

KENNETH C. JOHNSON (53)
5 years of service
Vice President, Generation

PEGGY S. LOYD (49)
28 years of service
Vice President, Customer Care

JAMES J. LUDWIG (48)
16 years of service
Vice President, Regulatory and Public Affairs

ANTHONY D. SOMMA (43)
12 years of service
Treasurer

LEE WAGES (58)
29 years of service
Vice President, Controller

CAROLINE A. WILLIAMS (50)
31 years of service
Vice President, Distribution Power Delivery

Ages and years of service are as of December 31, 2006.

Westar Energy®

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

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

FORM 10-K

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended **December 31, 2006**

or

[ ] TRANSITION REPORT PURSUANT SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _____to_____

Commission File Number	Exact name of registrant as specified in charter, state of incorporation, address of principal executive offices and telephone number	I.R.S. Employer Identification Number
001-32206	**GREAT PLAINS ENERGY INCORPORATED** (A Missouri Corporation) 1201 Walnut Street Kansas City, Missouri 64106 (816) 556-2200 www.greatplainsenergy.com	43-1916803
000-51873	**KANSAS CITY POWER & LIGHT COMPANY** (A Missouri Corporation) 1201 Walnut Street Kansas City, Missouri 64106 (816) 556-2200 www.kcpl.com	44-0308720

Each of the following classes or series of securities registered pursuant to Section 12(b) of the Act is registered on the New York Stock Exchange:

Registrant	Title of each class	
Great Plains Energy Incorporated	Cumulative Preferred Stock par value $100 per share	3.80%
	Cumulative Preferred Stock par value $100 per share	4.50%
	Cumulative Preferred Stock par value $100 per share	4.35%
	Common Stock without par value	
	Income PRIDES^{SM} (to February 16, 2007)	

Securities registered pursuant to Section 12(g) of the Act: Kansas City Power & Light Company Common Stock without par value.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Great Plains Energy Incorporated Yes X No _ Kansas City Power & Light Company Yes _ No X

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
Great Plains Energy Incorporated Yes _ No X Kansas City Power & Light Company Yes _ No X

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.
Great Plains Energy Incorporated Yes _ No X Kansas City Power & Light Company Yes _ No X

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 the Form 10-K.
Great Plains Energy Incorporated X Kansas City Power & Light Company X

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act.

Great Plains Energy Incorporated	Large accelerated filer X	Accelerated filer _	Non-accelerated filer _
Kansas City Power & Light Company	Large accelerated filer _	Accelerated filer _	Non-accelerated filer X

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Great Plains Energy Incorporated Yes _ No X Kansas City Power & Light Company Yes _ No X

The aggregate market value of the voting and non-voting common equity held by non-affiliates of Great Plains Energy Incorporated (based on the closing price of its common stock on the New York Stock Exchange on June 30, 2006) was approximately $2,234,971,993 All of the common equity of Kansas City Power & Light Company is held by Great Plains Energy Incorporated, an affiliate of Kansas City Power & Light Company.

On February 21, 2007, Great Plains Energy Incorporated had 85,925,671 shares of common stock outstanding. The aggregate market value of the common stock held by non-affiliates of Great Plains Energy Incorporated (based upon the closing price of its common stock on the New York Stock Exchange on February 21, 2007) was approximately $2,735,366,235. On February 21, 2007, Kansas City Power & Light Company had one share of common stock outstanding and held by Great Plains Energy Incorporated.

Kansas City Power & Light Company meets the conditions set forth in General Instruction (I)(1)(a) and (b) of Form 10-K and is therefore filing this Form 10-K with the reduced disclosure format.

Documents Incorporated by Reference

Portions of the 2007 Proxy Statement of **Great Plains Energy Incorporated** to be filed with the Securities and Exchange Commission are incorporated by reference in Part III of this report.

TABLE OF CONTENTS

This combined annual report on Form 10-K is being filed by Great Plains Energy Incorporated (Great Plains Energy) and Kansas City Power & Light Company (KCP&L). KCP&L is a wholly owned subsidiary of Great Plains Energy and represents a significant portion of its assets, liabilities, revenues, expenses and operations. Thus, all information contained in this report relates to, and is filed by, Great Plains Energy. Information that is specifically identified in this report as relating solely to Great Plains Energy, such as its financial statements and all information relating to Great Plains Energy's other operations, businesses and subsidiaries, including Strategic Energy, L.L.C. (Strategic Energy), does not relate to, and is not filed by, KCP&L. KCP&L makes no representation as to that information. Neither Great Plains Energy or Strategic Energy have any obligation in respect of KCP&L's debt securities and holders of such securities should not consider Great Plains Energy's or Strategic Energy's financial resources or results of operations in making a decision with respect to KCP&L's debt securities.

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. Forward-looking statements include, but are not limited to, statements regarding projected delivered volumes and margins, the outcome of regulatory proceedings, cost estimates of the comprehensive energy plan and other matters affecting future operations. 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, Great Plains Energy and KCP&L; 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; decisions of regulators regarding rates KCP&L can charge for electricity; adverse changes in applicable laws, regulations, rules, principles or practices governing tax, accounting and environmental matters including, but not limited to, air and water 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 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, quality and deliverability of fuel; ability to achieve generation planning goals and the occurrence and duration of unplanned generation outages; delays in the anticipated in-service dates and cost increases of additional generating capacity; nuclear operations; ability to enter new markets successfully and capitalize on growth opportunities in non-regulated businesses and the effects of competition; application of critical accounting policies, including, but not limited to, those related to derivatives and pension liabilities; workforce risks including compensation and benefits costs; performance of projects undertaken by non-regulated businesses and the success of efforts to invest in and develop new opportunities; the ability to successfully complete merger, acquisition or divestiture plans (including the acquisition of Aquila, Inc., and the sale of assets to Black Hills Corporation) and other risks and uncertainties.

This list of factors is not all-inclusive because it is not possible to predict all factors. Item 1A. Risk Factors included in this report should be carefully read for further understanding of potential risks to the companies. Other sections of this report and other periodic reports filed by the companies with the Securities and Exchange Commission (SEC) should also be read for more information regarding risk factors. Great Plains Energy and KCP&L undertake no obligation to publicly update or revise any forward-looking statement, whether as a result of new information, future events or otherwise.

GLOSSARY OF TERMS

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

Abbreviation or Acronym	Definition
ARO	Asset Retirement Obligation
BART	Best available retrofit technology
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
Clean Air Act	Clean Air Act Amendments of 1990
CO_2	Carbon Dioxide
Company	Great Plains Energy Incorporated and its subsidiaries
Consolidated KCP&L	KCP&L and its wholly owned subsidiaries
Digital Teleport	Digital Teleport, Inc.
DOE	Department of Energy
EBITDA	Earnings before interest, income taxes, depreciation and amortization
ECA	Energy Cost Adjustment
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℠	Flexible Equity Linked Preferred Increased Dividend Equity Securities, a service mark of Merrill Lynch & Co., Inc.
FERC	The Federal Energy Regulatory Commission
FIN	Financial Accounting Standards Board Interpretation
FSS	Forward Starting Swaps
GAAP	Generally Accepted Accounting Principles
GPP	Great Plains Power Incorporated
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
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 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
kWh	Kilowatt hour
MAC	Material Adverse Change
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations

Abbreviation or Acronym	Definition
MISO	Midwest Independent Transmission System Operator, Inc.
MPSC	Public Service Commission of the State of Missouri
MW	Megawatt
MWh	Megawatt hour
NEIL	Nuclear Electric Insurance Limited
NO_x	Nitrogen Oxide
NPNS	Normal Purchases and Normal Sales
NRC	Nuclear Regulatory Commission
OCI	Other Comprehensive Income
PJM	PJM Interconnection, LLC
PRB	Powder River Basin
PURPA	Public Utility Regulatory Policy Act
Receivables Company	Kansas City Power & Light Receivables Company, a wholly owned subsidiary of KCP&L
RTO	Regional Transmission Organization
SEC	Securities and Exchange Commission
SECA	Seams Elimination Charge Adjustment
SE Holdings	SE Holdings, L.L.C.
Services	Great Plains Energy Services Incorporated
SIP	State Implementation Plan
SFAS	Statement of Financial Accounting Standards
SO_2	Sulfur Dioxide
SPP	Southwest Power Pool, Inc.
Strategic Energy	Strategic Energy, L.L.C., a subsidiary of KLT Energy Services
T - Lock	Treasury Lock
Union Pacific	Union Pacific Railroad Company
WCNOC	Wolf Creek Nuclear Operating Corporation
Wolf Creek	Wolf Creek Generating Station
Worry Free	Worry Free Service, Inc., a wholly owned subsidiary of HSS

PART I

ITEM 1. BUSINESS

General

Great Plains Energy Incorporated and Kansas City Power & Light Company are separate registrants filing this combined annual report. 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.

Information in other Items of this report as to which reference is made in this Item 1. is hereby incorporated by reference in this Item 1. The use of terms such as see or refer to shall be deemed to incorporate into this Item 1. the information to which such reference is made.

GREAT PLAINS ENERGY

Great Plains Energy, a Missouri corporation incorporated in 2001 and headquartered in Kansas City, Missouri, is a public utility holding company and does not own or operate any significant assets other than the stock of its subsidiaries. Great Plains Energy has four direct subsidiaries with operations or active subsidiaries:

- KCP&L is described below.
- KLT Inc. is an intermediate holding company that primarily holds indirect interests in Strategic Energy, L.L.C. (Strategic Energy), which provides competitive retail electricity supply services in several electricity markets offering retail choice, and holds investments in affordable housing limited partnerships. KLT Inc. also wholly owns KLT Gas Inc. (KLT Gas), which has no active operations.
- 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 indirectly owns 100% of Strategic Energy.
- Great Plains Energy Services Incorporated (Services) provides services at cost to Great Plains Energy and its subsidiaries, including consolidated KCP&L.

CONSOLIDATED KCP&L

KCP&L, a Missouri corporation incorporated in 1922, is an integrated, regulated electric utility, which provides electricity to customers primarily in the states of Missouri and Kansas. KCP&L has two wholly owned subsidiaries, Kansas City Power & Light Receivables Company (Receivables Company) and Home Service Solutions Inc. (HSS). HSS has no active operations.

Business Segments of Great Plains Energy and KCP&L

Consolidated KCP&L's sole reportable business segment is KCP&L. Great Plains Energy, through its direct and indirect subsidiaries, has two reportable business segments: KCP&L and Strategic Energy.

For information regarding the revenues, income and assets attributable to the Company's reportable business segments, see Note 17 to the consolidated financial statements. Comparative financial information and discussion regarding the Company's and KCP&L's reportable business segments can be found in Item 7. MD&A.

KCP&L
KCP&L, headquartered in Kansas City, Missouri, is an integrated, regulated electric utility that engages in the generation, transmission, distribution and sale of electricity. KCP&L serves over 505,000 customers located in all or portions of 24 counties in western Missouri and eastern Kansas. Customers include approximately 446,000 residences, over 57,000 commercial firms, and approximately 2,200 industrials, municipalities and other electric utilities. KCP&L's retail revenues averaged approximately 81% of its total operating revenues over the last three years. Wholesale firm power, bulk power sales and miscellaneous electric revenues accounted for the remainder of utility revenues. KCP&L is significantly impacted by seasonality with approximately one-third of its retail revenues recorded in the third quarter. KCP&L's total electric revenues averaged approximately 43% of Great Plains Energy's revenues over the last three years. KCP&L's net income accounted for approximately 119%, 88% and 87% of Great Plains Energy's income from continuing operations in 2006, 2005 and 2004, respectively.

Regulation
KCP&L is regulated by the Public Service Commission of the State of Missouri (MPSC) and The State Corporation Commission of the State of Kansas (KCC) with respect to retail rates, certain accounting matters, standards of service and, in certain cases, the issuance of securities, certification of facilities and service territories. KCP&L is classified as a public utility under the Federal Power Act and accordingly, is subject to regulation by the Federal Energy Regulatory Commission (FERC). By virtue of its 47% ownership interest in Wolf Creek Generating Station (Wolf Creek), KCP&L is subject to regulation by the Nuclear Regulatory Commission (NRC), with respect to licensing, operations and safety-related requirements.

Missouri and Kansas jurisdictional retail revenues averaged 57% and 43%, respectively, of KCP&L's total retail revenue over the last three years. See Item 7. MD&A, Critical Accounting Policies section and Note 6 to the consolidated financial statements for additional information concerning regulatory matters.

Missouri and Kansas Rate Case Filings
In December 2006, KCP&L received orders from the MPSC and the KCC regarding its rate cases filed in February 2006. For information on these rate cases, see Note 6 to the consolidated financial statements. In February 2007, KCP&L filed a request with the MPSC for an annual rate increase of approximately $45 million. KCP&L is required to file a rate request with KCC on March 1, 2007.

Southwest Power Pool Regional Transmission Organization
In 2006, KCP&L received approval from both the MPSC and KCC to participate in the Southwest Power Pool, Inc. (SPP) Regional Transmission Organization (RTO). See Note 6 to the consolidated financial statements for further information.

Competition
Missouri and Kansas continue on the fully integrated utility model and no legislation authorizing retail choice has been introduced in Missouri or Kansas for several years. As a result, KCP&L does not compete with others to supply and deliver electricity in its franchised service territory, although other sources of energy can provide alternatives to KCP&L's customers. If Missouri or Kansas were to pass and implement legislation authorizing or mandating retail choice, KCP&L may no longer be able to apply regulated utility accounting principles to deregulated portions of its operations and may be required to write off certain regulatory assets and liabilities.

KCP&L competes in the wholesale market to sell power in circumstances when the power it generates is not required for customers in its service territory. In this regard, KCP&L competes with owners of other generating stations and other power suppliers, principally utilities in its region, on the basis of availability and price. In recent years, these wholesale sales have been an important source of

revenues to KCP&L. KCP&L's wholesale revenues averaged approximately 17% of its total revenues over the last three years.

Power Supply
KCP&L has over 4,000 MWs of generating capacity. KCP&L's maximum system net hourly summer peak load of 3,721 MW occurred on July 19, 2006. The maximum winter peak load of 2,563 MW occurred on December 7, 2005. During 2006, the winter peak load was 2,467 MW. The projected peak summer demand for 2007 is 3,677 MW. KCP&L expects to meet its projected capacity requirements for the years 2007 through 2009 with its generation assets, through short-term capacity purchases and demand-side management and efficiency programs. As part of its comprehensive energy plan, KCP&L installed 100.5 MW of wind generation in 2006 and expects to have Iatan No. 2, a coal-fired plant, in service in 2010.

KCP&L is a member of the SPP reliability region. As one of the ten regional members of the North American Electric Reliability Council, SPP is responsible for maintaining reliability in its area through coordination of planning and operations. As a member of the SPP, KCP&L is required to maintain a capacity margin of at least 12% of its projected peak summer demand. This net positive supply of capacity and energy is maintained through its generation assets and capacity, power purchase agreements and peak demand reduction programs. The capacity margin is designed to ensure the reliability of electric energy in the SPP region in the event of operational failure of power generating units utilized by the members of the SPP.

Fuel
The principal fuel sources for KCP&L's electric generation are coal and nuclear fuel. KCP&L expects, with normal weather, to satisfy approximately 96% of its 2007 generation requirements from these sources with the remainder provided by natural gas, oil and wind. The actual 2006 and estimated 2007 fuel mix and delivered cost in cents per net kWh generated are in the following table.

	Fuel Mix [a]		Fuel cost in cents per net kWh generated	
Fuel	Estimated 2007	Actual 2006	Estimated 2007	Actual 2006
Coal	74 %	75 %	1.28	1.15
Nuclear	22	22	0.45	0.43
Natural gas and oil	2	3	9.58	7.37
Wind	2	-	-	-
Total Generation	100 %	100 %	1.19	1.16

[a] Fuel mix based on percent of total MWhs generated.

Less than 1% of KCP&L's rates contain an automatic fuel adjustment clause. To the extent the price of coal, coal transportation, nuclear fuel, nuclear fuel processing, natural gas or purchased power increases significantly after the expiration of the contracts described in this section, or if KCP&L's lower fuel cost units do not meet anticipated availability levels, KCP&L's net income may be adversely affected until the increased cost could be reflected in rates. KCP&L will file an energy cost adjustment (ECA) clause as part of its Kansas rate case to be filed March 1, 2007.

Coal
During 2007, KCP&L's generating units, including jointly owned units, are projected to burn approximately 13.3 million tons of coal. KCP&L has entered into coal-purchase contracts with various suppliers in Wyoming's Powder River Basin (PRB), the nation's principal supply region of low-sulfur

coal, and with local suppliers. The coal to be provided under these contracts will satisfy all projected coal requirements for 2007 and approximately 95%, 45% and 35% for 2008 through 2010, respectively. The remainder of KCP&L's coal requirements will be fulfilled through additional contracts or spot market purchases. KCP&L has entered into its coal contracts over time at higher average prices affecting coal costs for 2007 and beyond.

KCP&L has also entered into rail transportation contracts with various railroads to transport coal from the PRB to its generating units. The transportation services to be provided under these contracts will satisfy virtually all of the projected requirements for 2007, more than 95% for 2008 and approximately 75% for 2009 and 2010. Coal transportation costs are expected to increase in 2007 and beyond. See Note 15 to the consolidated financial statements regarding a rate complaint case against Union Pacific Railroad Company.

Nuclear Fuel

KCP&L owns 47% of Wolf Creek Nuclear Operating Corporation (WCNOC), the operating company for Wolf Creek, its only nuclear generating unit. Wolf Creek purchases uranium and has it processed for use as fuel in its reactor. This process involves conversion of uranium concentrates to uranium hexafluoride, enrichment of uranium hexafluoride and fabrication of nuclear fuel assemblies. The owners of Wolf Creek have on hand or under contract all of the uranium and conversion services needed to operate Wolf Creek through March 2011 and approximately 75% after that date through September 2018. A supply interruption at a major uranium mine owned in part by one of Wolf Creek's suppliers will result in deferral of a small portion of the uranium scheduled for delivery to Wolf Creek in 2007. It is possible that this supply interruption will impact small portions of Wolf Creek's uranium deliveries beyond 2007 as well. In anticipation of this possibility, the owners of Wolf Creek authorized the purchase of additional uranium from an alternate supplier. That purchase, combined with strategic inventory acquired earlier in 2005 and other strategies that have already been adopted, minimizes the risks from such supply interruptions. The owners also have under contract 100% of the uranium enrichment and fabrication required to operate Wolf Creek through March 2025.

Management expects its cost of nuclear fuel to remain relatively stable through 2009 because of contracts in place. Between 2010 and 2018, management anticipates the cost of nuclear fuel to increase approximately 30% to 50% due to higher contracted prices and market conditions. Even with this anticipated increase, management expects nuclear fuel cost per MWh generated to remain less than the cost of other fuel sources.

All uranium, uranium conversion and uranium enrichment arrangements, as well as the fabrication agreement, have been entered into in the ordinary course of business. However, contraction and consolidation among suppliers of these commodities and services, coupled with increasing worldwide demand and inventory drawdowns, have introduced uncertainty as to Wolf Creek's ability to replace some of these contracts in the event of a protracted supply disruption. Great Plains Energy's management believes this risk is common to the nuclear industry. Accordingly, in the event the affected contracts were required to be replaced, Great Plains Energy's and Wolf Creek's management believe that the industry and government would work together to minimize disruption of the nuclear industry's operations, including Wolf Creek's operations.

See Note 5 to the consolidated financial statements for additional information regarding nuclear plant.

Natural Gas

KCP&L is projecting decreased use of natural gas during 2007. At December 31, 2006, KCP&L had hedged approximately 30% and 9% of its 2007 and 2008, respectively, projected natural gas usage for generation requirements to serve retail load and firm MWh sales.

Purchased Power
At times, KCP&L purchases power to meet its customers' needs. Management believes KCP&L will be able to obtain enough power to meet its future demands due to the coordination of planning and operations in the SPP region; however, price and availability of power purchases may be impacted during periods of high demand. KCP&L's purchased power, as a percent of MWh requirements, averaged approximately 3% for 2006, 2005 and 2004.

Environmental Matters
See Note 13 to the consolidated financial statements for information regarding environmental matters.

STRATEGIC ENERGY
Great Plains Energy indirectly owns 100% of Strategic Energy. Strategic Energy provides competitive retail electricity supply services by entering into power supply contracts to supply electricity to its end-use customers. Of the states that offer retail choice, Strategic Energy operates in California, Illinois, Maryland, Massachusetts, Michigan, New Jersey, New York, Ohio, Pennsylvania and Texas. Strategic Energy has begun expansion into Connecticut. Strategic Energy also provides strategic planning, consulting and billing and scheduling services in the natural gas and electricity markets.

Strategic Energy provides services to approximately 88,200 commercial, institutional and small manufacturing accounts for approximately 25,000 customers, including numerous Fortune 500 companies, smaller companies and governmental entities. Strategic Energy offers an array of products designed to meet the various requirements of a diverse customer base including fixed price, index-based and month-to-month renewal products. Strategic Energy's projected MWh deliveries for 2007 are in the range of 18 to 22 million MWhs. Based solely on expected usage under current signed contracts, Strategic Energy has forecasted future MWh commitments (backlog) of 14.7 million, 8.9 million and 4.1 million for the years 2007 through 2009, respectively, and 5.1 million over the years 2010 through 2012.

Strategic Energy's revenues averaged approximately 57% of Great Plains Energy's revenues over the last three years. Strategic Energy's net income (loss) accounted for approximately (8%), 17% and 24% of Great Plains Energy's income from continuing operations in 2006, 2005 and 2004, respectively.

Strategic Energy's growth objective is to continue to expand in retail choice states and to increase its share of a large market opportunity. Strategic Energy's continued success is dependent on a number of industry and operational factors including, but not limited to, the ability to contract for wholesale MWhs to meet its customers' needs at prices that are competitive with the host utility territory rates and with current and/or future competitors, the ability to provide value-added customer services and the ability to attract and retain employees experienced in providing service in retail choice states.

Power Supply
Strategic Energy does not own any generation, transmission or distribution facilities. Strategic Energy purchases electricity from power suppliers based on forecasted peak demand for its retail customers. Management believes it will have adequate access to energy in the markets it serves.

Regulation
Strategic Energy, as a participant in the wholesale electricity and transmission markets, is subject to FERC jurisdiction. Additionally, Strategic Energy is subject to regulation by state regulatory agencies in states where Strategic Energy is licensed to sell power. 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 compete in any jurisdiction.

Transmission
In many markets, Regional Transmission Organizations (RTO)/Independent System Operators (ISO) manage the power flows, maintain reliability and administer transmission access for the electric transmission grid in a defined region. RTOs/ISOs coordinate and monitor communications among the generator, distributor and retail electricity provider. Additionally, RTOs/ISOs manage the real-time electricity supply and demand, and direct the energy flow. Through these activities, RTOs/ISOs maintain a reliable energy supply within their region.

As a competitive retail electricity supplier, Strategic Energy must register with each RTO/ISO in order to operate in the markets covered by their grids. Strategic Energy primarily engages with PJM Interconnection, LLC (PJM), New England RTO (formerly ISO-New England), California ISO, New York ISO, Electric Reliability Council of Texas (ERCOT) and the Midwest Independent Transmission System Operator, Inc. (MISO).

In some cases, RTO/ISOs provide Strategic Energy with all or a combination of the data for billing, settlement, application of electricity rates and information regarding the imbalance of electricity supply. In addition, they provide balancing energy services and ancillary services to Strategic Energy in the fulfillment of providing services to retail end users. Strategic Energy must go through a settlement process with each RTO/ISO in which the RTO/ISO compares scheduled power with actual meter usage during a given time period and adjusts the original costs charged to Strategic Energy through a revised settlement. All participants in the RTOs/ISOs have exposure to other market participants. In the event of default by a market participant within the RTOs/ISOs, the uncollectible balance is generally allocated to the remaining participants in proportion to their load share.

RTOs/ISOs may continue to modify the market structure and mechanisms in an attempt to improve market efficiency. In addition, existing regulations may be revised or reinterpreted and new laws and regulations may be adopted or become applicable to Strategic Energy's activities. These actions could have an effect on Strategic Energy's results of operations. Strategic Energy participates extensively, together with other market participants, in relevant RTO/ISO governance and regulatory issues.

Seams Elimination Charge Adjustment
Seams Elimination Charge Adjustment (SECA) is a transitional pricing mechanism authorized by FERC and intended to compensate transmission owners for the revenue lost as a result of FERC's elimination of regional through and out rates between PJM and MISO during a 16-month transition period from December 1, 2004, through March 31, 2006. See Note 6 to the consolidated financial statements for further information regarding SECA.

Revenue Sufficiency Guarantee
Since the April 2005 implementation of MISO market operations, MISO's business practice manuals and other instructions to market participants have stated that Revenue Sufficiency Guarantee (RSG) charges will not be imposed on day-ahead virtual offers to supply power not supported by actual generation. RSG charges are collected by MISO in order to compensate generators that are standing by to supply electricity when called upon by MISO. See Note 6 to the consolidated financial statements for further information regarding RSG.

Competition
The principal elements of competition are price, service and product differentiation. Strategic Energy operates in several retail choice electricity markets. Strategic Energy has several competitors that operate in most or all of the same states in which it provides services to customers. Strategic Energy 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. There is a regulatory lag in several RTOs/ISOs that slows the adjustment of host public utility rates in response to changes in wholesale prices, which may negatively affect Strategic Energy's ability to compete in a rising wholesale price environment.

GREAT PLAINS ENERGY AND CONSOLIDATED KCP&L EMPLOYEES

At December 31, 2006, Great Plains Energy had 2,470 employees. Consolidated KCP&L had 2,140 employees, including 1,364 represented by three local unions of the International Brotherhood of Electrical Workers (IBEW). KCP&L has labor agreements with Local 1613, representing clerical employees (expires March 31, 2008), with Local 1464, representing transmission and distribution workers (expires January 31, 2009), and with Local 412, representing power plant workers (expires February 28, 2007, with contract negotiations currently ongoing).

Officers

All of the individuals in the following table have been officers or employees in a responsible position with the Company for the past five years except as noted in the footnotes. The term of office of each officer commences with his or her appointment by the Board of Directors and ends at such time as the Board of Directors may determine. There are no family relationships between any of the executive officers, nor any arrangement or understanding between any executive officer and any other person involved in officer selection.

Officers of Great Plains Energy

Name	Age	Current Position(s)	Year First Assumed An Officer Position
Michael J. Chesser [(a)*]	58	Chairman of the Board and Chief Executive Officer	2003
William H. Downey [(b)*]	62	President and Chief Operating Officer	2000
Terry Bassham [(c)*]	46	Executive Vice President, Finance and Strategic Development and Chief Financial Officer	2005
Michael W. Cline [(d)]	45	Treasurer and Chief Risk Officer	2003
Barbara B. Curry [(e)*]	52	Senior Vice President, Corporate Services and Corporate Secretary	2005
Michael L. Deggendorf [(f)]	45	Vice President, Public Affairs	2005
Stephen T. Easley [(g)*]	51	Senior Vice President, Supply – KCP&L	2000
Mark G. English [(h)]	55	General Counsel and Assistant Secretary	2003
Todd A. Kobayashi [(i)]	39	Vice President, Strategy and Investor Relations	2005
Shahid Malik [(j)*]	46	Executive Vice President President and Chief Executive Officer – Strategic Energy	2004
John R. Marshall [(k)*]	57	Senior Vice President, Delivery – KCP&L	2005
Victoria L. Schatz [(l)]	37	Assistant General Counsel and Assistant Secretary	2006
Lori A. Wright [(m)*]	44	Controller	2002

Officers of KCP&L

Name	Age	Current Position(s)	Year First Assumed An Officer Position
Michael J. Chesser [(a)*]	58	Chairman of the Board	2003
William H. Downey [(b)*]	62	President and Chief Executive Officer	2000
Terry Bassham [(c)*]	46	Chief Financial Officer	2005
Kevin E. Bryant [(n)]	31	Vice President, Energy Solutions	2006
Lora C. Cheatum [(o)]	50	Vice President, Administrative Services	2005
Michael W. Cline [(d)]	45	Treasurer	2003
F. Dana Crawford [(p)]	56	Vice President, Plant Operations	2005
Barbara B. Curry [(e)*]	52	Secretary	2005
Stephen T. Easley [(g)*]	51	Senior Vice President, Supply	2000
Mark G. English [(h)]	55	Assistant Secretary	2003
Chris B. Giles [(q)]	53	Vice President, Regulatory Affairs	2005
William P. Herdegen III	52	Vice President, Customer Operations	2001
John R. Marshall [(k)*]	57	Senior Vice President, Delivery	2005
William G. Riggins [(r)]	48	Vice President, Legal and Environmental Affairs and General Counsel	2000
Marvin L. Rollison [(s)]	54	Vice President, Corporate Culture and Community Strategy	2005
Victoria L. Schatz [(l)]	37	Assistant General Counsel and Assistant Secretary	2006
Richard A. Spring	52	Vice President, Transmission	1994
Lori A. Wright [(m)*]	44	Controller	2002

* Designated an executive officer.

(a) Mr. Chesser was previously Chief Executive Officer of United Water (2002-2003) and President and Chief Executive Officer of GPU Energy (2000-2002).

(b) Mr. Downey was previously Executive Vice President of Great Plains Energy (2001- 2003) and Executive Vice President of KCP&L (2000-2002) and President – KCP&L Delivery Division (2000-2002).

(c) Mr. Bassham was previously Executive Vice President, Chief Financial and Administrative Officer (2001-2005) of El Paso Electric Company.

(d) Mr. Cline was previously Treasurer of Great Plains Energy (2005), Assistant Treasurer of Great Plains Energy and KCP&L (2003-2005), and Director, Corporate Finance (2001-2002) of Great Plains Energy.

(e) Ms. Curry was previously Senior Vice President, Retail Operations (2003-2004) and Executive Vice President, Global Human Resources (2001-2003) of TXU Corporation.

(f) Mr. Deggendorf was previously Senior Director, Energy Solutions of KCP&L (2002-2005), Senior Vice President of Everest Connections, a cable services company (2000-2002) and Vice President of UtiliCorp Communications (2000-2002).

(g) Mr. Easley was previously Vice President, Generation Services (2002-2005), and President and CEO of GPP (2001-2002). He was promoted to Senior Vice President, Supply of KCP&L in March 2005.

(h) Mr. English was previously Corporate Counsel and Assistant Secretary (2003-2005) and Corporate Counsel (2001-2003) of Great Plains Energy.

(i) Mr. Kobayashi was previously Investor Relations Officer (2002-2005) and Director–Investor Relations and Corporate Development of Lante Corporation, a technology consulting firm (2000-2002).

(j) Mr. Malik was appointed as President and Chief Executive Officer of Strategic Energy effective November 10, 2004 and was appointed Executive Vice President of Great Plains Energy effective January 1, 2006. Mr. Malik was previously a partner of Sirius Solutions LLP, a consulting company, (2002-2004) and President of Reliant Energy Wholesale Marketing Group (1999-2002).

(k) Mr. Marshall was previously President of Coastal Partners, Inc., a strategy consulting company (2001-2005), and Senior Vice President, Customer Service of Tennessee Valley Authority (2002-2004).

(l) Ms. Schatz was previously Managing Attorney (2003-2006) and Senior Attorney (2002-2003) of KCP&L, and in private practice with the Levy & Craig law firm (1999-2002).

(m) Ms. Wright served as Assistant Controller of KCP&L from 2001 until named Controller in 2002.

(n) Mr. Bryant was previously Manager, Corporate Finance (2005-2006) and Senior Financial Analyst, Corporate Finance (2003-2005) of Great Plains Energy. Previously he served in successive positions as Senior Treasury Analyst and Manager, Strategic Planning for THQ, Inc., a software company, (2002-2003).

(o) Ms. Cheatum was previously Interim Vice President, Human Resources (2004-2005) and Director, Human Resources (2001-2004) of KCP&L.

(p) Mr. Crawford was previously Plant Manager (1994-2005) of KCP&L's LaCygne Generating Station.

(q) Mr. Giles was previously Senior Director, Regulatory Affairs and Business Planning (2004-2005) and Director, Regulatory Affairs of KCP&L (1993-2004).

(r) Mr. Riggins was previously General Counsel of Great Plains Energy (2000-2005).

(s) Mr. Rollison was previously Supervisor-Engineering of KCP&L (2000-2005).

Available Information

Great Plains Energy's website is www.greatplainsenergy.com and KCP&L's website is www.kcpl.com. Information contained on the companies' websites is not incorporated herein. Both companies make available, free of charge, on or through their websites, their annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act as soon as reasonably practicable after the companies electronically file such material with, or furnish it to, the SEC. In addition, the companies make available on or through their websites all other reports, notifications and certifications filed electronically with the SEC.

The public may read and copy any materials that the companies file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC, 20549. For information on the operation of the Public Reference Room, please call the SEC at 1-800-SEC-0330. The SEC also maintains an Internet site at http://www.sec.gov that contains reports, proxy statements and other information regarding the companies.

ITEM 1A. 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. The companies' business is influenced by many factors that are difficult to predict, involve uncertainties that may materially affect actual results and are often beyond the companies' control. Additional risks and uncertainties not presently known or that the companies' management currently believes to be immaterial may also adversely affect the companies. The risk factors described below, as well as the other information included in this Annual Report and in the other documents filed with the SEC, should be carefully considered before making an investment in the Company's securities. Risk factors of consolidated KCP&L are also risk factors for Great Plains Energy.

The Company has Regulatory Risks

The Company is subject to extensive federal and state regulation, as described below. Failure to obtain adequate rates or regulatory approvals, in a timely manner, 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 outcome of KCP&L's pending and future retail rate proceedings could have a material impact on its business and are largely outside its control.
The rates, which KCP&L is allowed to charge its customers, are the single most important item influencing its results of operations, financial position and liquidity. These rates are subject to the determination, in large part, of governmental entities outside of KCP&L's control, including the MPSC, KCC and FERC. Decisions made by these entities could have a material impact on KCP&L's business including its results of operations and financial position.

In February 2007, KCP&L filed a request with the MPSC to increase the annual rates charged to its retail customers in Missouri by approximately $45 million. KCP&L has also committed to file a request to increase the rates it is permitted to charge its Kansas retail customers with KCC by March 1, 2007. The requested rate increases are subject to the approval of the MPSC and KCC, which are expected to rule on the requests within eleven and nine months, respectively, of the filing dates. It is possible that the MPSC and/or KCC will authorize a lower rate increase than what KCP&L has requested, or no increase or a rate reduction. Additionally, the December 2006 order of the MPSC authorizing an increase in annual rates of approximately $51 million has been appealed in the Missouri courts. It is possible that the MPSC order could be vacated and the proceedings remanded to the MPSC. Management cannot predict or provide any assurances regarding the outcome of these proceedings.

As a part of the Missouri and Kansas stipulations approved by the MPSC and KCC in 2005, KCP&L began implementation of its comprehensive energy plan. Under the comprehensive energy plan, KCP&L agreed to undertake certain projects, including building and owning a portion of Iatan No. 2, installing a new wind-powered generating facility, installing environmental upgrades to certain existing plants, infrastructure improvements and demand management, distributed generation, and customer efficiency and affordability programs. A reduction or rejection by the MPSC or KCC of rate increase requests may result in increased financing requirements for KCP&L. This could have a material impact on its results of operations and financial position.

In response to competitive, economic, political, legislative and regulatory pressures, KCP&L may be subject to rate moratoriums, rate refunds, limits on rate increases or rate reductions, including phase-in plans designed to spread the impact of rate increases over an extended period of time for the benefit of customers. Any or all of these could have a significant adverse effect on KCP&L's results of operations and financial position.

The ability of Strategic Energy to compete in states offering retail choice may be materially affected by state regulations and host public utility rates.
Strategic Energy is a participant in the wholesale electricity and transmission markets, and is subject to FERC regulation with respect to wholesale electricity sales and transmission matters. 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 compete in any jurisdiction. 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 long-term capital markets as significant sources of liquidity for capital requirements not satisfied by cash flows from operations. The Company also relies on the financial markets for credit support, such as letters of credit, to support Strategic Energy and KCP&L operations. KCP&L's capital requirements are expected to increase substantially over the next several years as it implements the generation and environmental projects in

its comprehensive energy plan. The amount of credit support required for Strategic Energy operations varies with a number of factors, including the amount and price of power purchased for its customers. The Company's management believes that it will maintain sufficient access to these financial markets at a reasonable cost based upon current credit ratings and market conditions. However, changes in financial or other market conditions or credit ratings could adversely affect its ability to access financial markets at a reasonable cost, impact the rate treatment provided KCP&L, or both, and therefore materially affect its results of operations and financial position.

Great Plains Energy, KCP&L and certain of their securities are rated by Moody's Investors Service 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.

Great Plains Energy is subject to business and regulatory uncertainties as a result of the anticipated acquisition of Aquila, Inc., which could adversely affect its business.
On February 7, 2007, Great Plains Energy announced that it had entered into definitive agreements under which it would acquire all the outstanding shares of Aquila, Inc. (Aquila). Immediately prior to this acquisition, Black Hills Corporation would acquire from Aquila its electric utility in Colorado and its gas utilities in Colorado, Kansas, Nebraska and Iowa. These transactions are complex, and are subject to Great Plains Energy and Aquila shareholder approvals, numerous regulatory approvals and other conditions. The timing of, and the conditions imposed by, regulatory approvals may delay, or give rise to the ability to terminate, the transactions. In the event of termination, the Company would be required to write-off its deferred transactions costs, which could be material. The conditions imposed by regulatory approvals could increase the costs, or decrease the benefits, anticipated by the Company from the transaction.

While it is anticipated that Great Plains Energy, KCP&L and Aquila will be rated investment grade after the transactions close, Great Plains Energy and KCP&L credit ratings have been negatively affected after the announcement of the proposed acquisition, and may be further negatively affected. Credit rating downgrades could result in higher financing costs and potentially limit the companies' access to the capital and credit markets, impact the rate treatment provided KCP&L, or both.

Great Plains Energy entered into the transaction agreements with the expectation that the acquisition would result in various benefits to it and KCP&L including, among other things, synergies, cost savings and operating efficiencies. Although the Company expects to achieve the anticipated benefits of the acquisition, achieving them cannot be assured. The Company expects to propose to regulators that the benefits resulting from the transaction be shared between retail electric customers and Company shareholders, and will request certain other regulatory assurances. There is no assurance regarding the amount of benefit-sharing, or other regulatory treatment, in rate cases occurring after the closing of the transactions.

Additionally, Aquila's utility operations are subject to regulation by numerous government entities, including the MPSC and FERC, and have pending MPSC rate cases, the outcome of which are subject to uncertainty. As such, a successful acquisition of Aquila will subject Great Plains Energy to additional regulatory risk.

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 and derivative instruments. The adoption of new Generally Accepted Accounting Principles (GAAP) or changes to current accounting policies or interpretations of such policies may materially affect the Company's results of operations and financial position.

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 quality 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.

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, conditions imposed in permits and the outcome of the appeal of KCP&L's Iatan Station air permit may materially affect the cost and timing of the generation and environmental retrofit projects included in the comprehensive energy plan, among other projects, and thus 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 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.

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, particularly KCP&L. 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.

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 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 stations use water from the Missouri River for cooling purposes. Low water and flow levels, which have been experienced in recent years,

can increase KCP&L's maintenance costs at these stations and, if these levels were to get low enough, could cause KCP&L to modify plant operations.

KCP&L and Strategic Energy have Commodity Price Risks
KCP&L and Strategic Energy engage in the wholesale and retail marketing of electricity and 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
Less than 1% of KCP&L's rates contain an automatic fuel adjustment clause, 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 does not hedge its entire exposure from fossil fuel and transportation price volatility. Consequently, its results of operations and financial position may be materially impacted by changes in these prices until increased costs are recovered in rates.

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 price 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.

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. 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. 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. Consequently, its results of operations and financial position may be materially impacted by changes in the wholesale price of electricity.

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; transmission scheduling; and catastrophic events such as fires, explosions, severe weather or other similar occurrences.

These and other operating events may reduce KCP&L's revenues or increase its costs, or both, and may materially affect KCP&L's results of operations and financial position.

KCP&L has Construction-Related Risks
KCP&L's comprehensive energy plan includes the construction of an estimated 850 MW coal-fired generating plant and environmental retrofits at two existing coal-fired units. KCP&L has not recently managed a construction program of this magnitude. There are risks that actual costs may exceed budget estimates, delays may occur in obtaining permits and materials, suppliers and contractors may not perform as required under their contracts, the scope and timing of projects may change, and other events beyond KCP&L's control may occur that may materially affect the schedule, budget and performance of these projects.

The anticipated acquisition of Aquila will increase Great Plains Energy's ownership of Iatan Nos. 1 and 2. Aquila owns 18% of both Iatan generating units. Great Plains Energy's post-acquisition ownership percentages of the Iatan generating units would be 88% of Iatan No. 1 and 72.71% of Iatan No. 2.

The construction projects contemplated in the comprehensive energy plan rely upon the supply of a significant percentage of materials from overseas sources. This global procurement subjects the delivery of procured material to issues beyond what would be expected if such material were supplied from sources within the United States. These risks include, but are not limited to, delays in clearing customs, ocean transportation and potential civil unrest in sourcing countries, among others. Additionally, as with any major construction program, inadequate availability of qualified craft labor may have an adverse impact on both the estimated cost and completion date of the projects.

KCP&L's estimated capital expenditures for its comprehensive energy plan have increased. The primary driver of the increased cost estimate is the environmental retrofit of two existing coal-fired plants. The demand for environmental projects has increased substantially with many utilities in the United States starting similar projects to address changing environmental regulations. This demand has constrained labor and material resources resulting in a significant escalation in the estimated cost and completion times for environmental retrofits, as well as for the other comprehensive energy plan projects. The second phase of environmental upgrades at LaCygne No. 1 is currently in the planning stage, and the market conditions noted above could impact the scope and timing.

These and other risks may increase the estimated costs of these construction projects, delay the in-service dates of these projects, or require KCP&L to purchase additional electricity to supply its retail customers until the projects are completed, and may materially affect KCP&L's results of operations and financial position.

Failure of one or more generation plant co-owners to pay their share of construction, operations and maintenance costs could increase KCP&L's costs and capital requirements.
KCP&L owns 47% of Wolf Creek, 50% of LaCygne Station, 70% of Iatan No. 1 and 55% of Iatan No. 2. The remaining portions of these facilities are owned by other utilities that are contractually obligated to pay their proportionate share of capital and other costs and, in the case of Iatan No. 2, construction costs.

While the ownership agreements provide that a defaulting co-owner's share of the electricity generated can be sold by the non-defaulting co-owners, there is no assurance that the revenues received will recover the increased costs borne by the non-defaulting co-owners. Further, the Iatan No. 2 agreements provide during the construction period for re-allocations of part or all of a defaulting co-owner's share of the facility to the non-defaulting owners, which would increase the capital, operations and maintenance costs of the non-defaulting owners. While management considers these matters to be unlikely, their occurrence could materially increase KCP&L's costs and capital requirements.

KCP&L has Retirement-Related Risks
Through 2010, approximately 20% of KCP&L's current employees will be eligible to retire with full pension benefits. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to the new employees, may adversely affect KCP&L's ability to manage and operate its business.

Substantially all of KCP&L's employees participate in defined benefit and post-retirement plans. If KCP&L employees retire when they become eligible for retirement through 2010, or if KCP&L's plans experience adverse market returns on its investments, or if interest rates materially fall, KCP&L's contributions to the plans could rise substantially over historical levels. In addition, assumptions related to future costs, returns on investments, interest rates and other actuarial assumptions, including projected retirements, have a significant impact on KCP&L's results of operations and financial position.

The Pension Protection Act of 2006 alters the manner in which pension plan assets and liabilities are valued for purposes of calculating required pension contributions and changes the timing of required contributions to underfunded plans. The funding rules, which become effective in 2008, could significantly affect the Company's funding requirements. In addition, the Financial Accounting Standards Board (FASB) has a project to reconsider the accounting for pensions and other post-retirement benefits. This project may result in accelerated expense.

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, shut down 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 outage 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 outage 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; however, should this happen, management 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.

KCP&L's participation in the SPP could increase costs, reduce revenues, and reduce KCP&L's control over its transmission assets.
Functional control of the KCP&L transmission systems was transferred to the SPP during the third quarter of 2006. KCP&L may be required to incur expenses or expand its transmission systems, which it would seek recovery for through rate increases, according to decisions made by the SPP rather than according to its internal planning process.

The SPP Energy Imbalance Service (EIS) Market, which began operation on February 1, 2007, is designed to improve transparency of power pricing and efficiency in generation dispatch. This is a new and complex market, which may result in significant price volatility and suboptimal dispatching of power plants. In addition, the sale of power in this market-based environment may result in unanticipated transmission congestion and other settlement charges.

Until KCP&L achieves a greater degree of operational experience participating in the SPP, including the SPP EIS Market, there is uncertainty as to the impact of its participation. In addition, there is uncertainty regarding the impact of ongoing RTO developments at FERC. KCP&L is unable to predict the impact these issues could have on its results of operations and financial position.

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 it serves customers. 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 must compete with the host utility in order to convince customers to switch from the host utility to Strategic Energy as their electric service provider. 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 Credit Risk
Strategic Energy has credit risk exposure in the form of the loss that it could incur if a counterparty failed to perform under its contractual obligations. Strategic Energy enters into forward contracts with multiple suppliers. In the event of supplier non-delivery or default, Strategic Energy's results of operations may 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. Strategic Energy's results of operations may also be affected, in a given period, if it were required to make a payment upon termination of a supplier contract to the extent the contracted price with the supplier exceeded the market value of the contract at the time of termination. Additionally, Strategic Energy's results of operations may be affected by increased bad debt expense if retail customers failed to satisfy their contractual obligations to pay Strategic Energy for electricity.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

KCP&L Generation Resources

	Unit	Year Completed	Estimated 2007 MW Capacity	Primary Fuel
Base Load	Wolf Creek	1985	548 [a]	Nuclear
	Iatan No. 1	1980	460 [a] [b]	Coal
	LaCygne No. 2	1977	341 [a]	Coal
	LaCygne No. 1	1973	368 [a]	Coal
	Hawthorn No. 5 [c]	1969	563	Coal
	Montrose No. 3	1964	176	Coal
	Montrose No. 2	1960	164	Coal
	Montrose No. 1	1958	170	Coal
Peak Load	West Gardner Nos. 1, 2, 3 and 4 [d]	2003	308	Natural Gas
	Osawatomie [d]	2003	77	Natural Gas
	Hawthorn No. 9 [e]	2000	130	Natural Gas
	Hawthorn No. 8 [d]	2000	77	Natural Gas
	Hawthorn No. 7 [d]	2000	77	Natural Gas
	Hawthorn No. 6 [d]	1997	136	Natural Gas
	Northeast Nos. 17 and 18 [e]	1977	117	Oil
	Northeast Nos. 15 and 16 [e]	1975	116	Oil
	Northeast Nos. 13 and 14 [e]	1976	114	Oil
	Northeast Nos. 11 and 12 [e]	1972	111	Oil
	Northeast Black Start Unit	1985	2	Oil
Wind	Spearville Wind Energy Facility[f]	2006	-	Wind
Total			4,055	

[a] KCP&L's share of a jointly owned unit.

[b] The Iatan No. 2 air permit limits KCP&L's accredited capacity of Iatan No. 1 to 460 MWs from 469 MWs until the air quality control equipment included in the comprehensive energy plan is operational.

[c] The Hawthorn Generating Station returned to commercial operation in 2001 with a new boiler, air quality control equipment and an uprated turbine following a 1999 explosion.

[d] Combustion turbines.

[e] Heat Recovery Steam Generator portion of combined cycle.

[f] In 2006, KCP&L completed the 100.5 MW Spearville Wind Energy Facility in Spearville, KS. Wind is not currently eligible for accredited capacity under SPP reliability standards.

KCP&L owns the Hawthorn Station (Jackson County, Missouri), Montrose Station (Henry County, Missouri), Northeast Station (Jackson County, Missouri), West Gardner Station (Johnson County, Kansas), Osawatomie Station (Miami County, Kansas) and Spearville Wind Energy Facility (Ford County, Kansas). KCP&L also owns 50% of the 736 MW LaCygne No. 1 and 682 MW LaCygne No. 2 (Linn County, Kansas), 70% of the 657 MW Iatan No. 1 (Platte County, Missouri) and 47% of the 1,166 MW Wolf Creek Unit (Coffey County, Kansas). See Note 6 to the consolidated financial statements for information regarding KCP&L's comprehensive energy plan and the construction of new generation capacity.

KCP&L Transmission and Distribution Resources

KCP&L's electric transmission system interconnects with systems of other utilities for reliability and to permit wholesale transactions with other electricity suppliers. KCP&L owns over 1,700 miles of

transmission lines, approximately 9,000 miles of overhead distribution lines and over 3,800 miles of underground distribution lines in Missouri and Kansas. KCP&L has all the franchises necessary to sell electricity within its retail service territory. KCP&L's transmission and distribution systems are continuously monitored for adequacy to meet customer needs. Management believes the current systems are adequate to serve its customers.

KCP&L General
KCP&L's principal plants and properties, insofar as they constitute real estate, are owned in fee simple except for the Spearville Wind Energy Facility, which is on land held under easements. Certain other facilities are located on premises held under leases, permits or easements. KCP&L electric transmission and distribution systems are for the most part located over or under highways, streets, other public places or property owned by others for which permits, grants, easements or licenses (deemed satisfactory but without examination of underlying land titles) have been obtained.

Substantially all of the fixed property and franchises of KCP&L, which consists principally of electric generating stations, electric transmission and distribution lines and systems, and buildings subject to exceptions and reservations, are subject to a General Mortgage Indenture and Deed of Trust dated as of December 1, 1986. General mortgage bonds totaling $159.3 million were outstanding at December 31, 2006.

ITEM 3. LEGAL PROCEEDINGS

KCP&L Missouri Rate Cases
On February 1, 2007, KCP&L filed a retail rate case with the MPSC, requesting an annual rate increase effective January 1, 2008, of approximately $45 million over current levels. Hearings on this case are expected to begin in the fall of 2007, with a decision expected in December 2007.

On February 1, 2006, KCP&L filed a request with the MPSC to increase annual rates $55.8 million for customers served in Missouri. The amount of the request was based, among other things, on a return on equity of 11.5% and an adjusted equity ratio of 53.8%. On December 21, 2006, the MPSC issued its order with an effective date of December 31, 2006. The order approved an approximate $51 million increase in annual revenues, reflecting an authorized return on equity of 11.25%. Approximately $22 million of the rate increase results from additional amortization to help maintain cash flow levels. The rates established by the order reflect an annual offset of approximately $69 million ($39 million Missouri jurisdiction) related to annual non-firm wholesale electric sales margin. The amount by which the actual margin amount is higher than this level will be recorded as a regulatory liability and reflected in KCP&L's next rate case. The order established, for regulatory purposes, annual pension cost recovery for the period beginning January 1, 2007, of approximately $35 million ($19 million Missouri jurisdiction), which excludes allocations to the other joint owners of generation facilities and capitalized amounts. The order also established, effective January 1, 2006, a regulatory asset or liability as appropriate for amounts arising from defined benefit plan settlements and curtailments which will be amortized over a five-year period beginning with the effective date of rates approved in KCP&L's next rate case. The rates set by the order also reflect the MPSC's decisions on various other accounting and regulatory matters. Appeals of the December 21, 2006, order of the MPSC authorizing an increase in annual rates of approximately $51 million were filed in February 2007 with the Circuit Court of Cole County, Missouri, by the Office of Public Counsel, Praxair, Inc., and Trigen-Kansas City Energy Corporation. The appeals seek to set aside or remand the order to the MPSC. Although subject to the appeals, the MSPC order remains in effect pending the court's decision.

KCP&L Kansas Rate Case
On February 1, 2006, KCP&L filed a request with KCC to increase annual rates $42.3 million for customers served in Kansas. KCP&L reached a negotiated settlement of its request with certain

parties to the rate proceedings, and filed a Stipulation and Agreement (Agreement) on September 29, 2006, containing the settlement with KCC. On December 4, 2006, KCC issued its order approving the Agreement in its entirety. The order approved a $29 million increase in annual revenues effective January 1, 2007, with $4 million of that amount resulting from additional depreciation to help maintain cash flow levels. The order also approved various accounting and other matters, including but not limited to: (i) establishing, for regulatory purposes, annual pension cost for the period beginning January 1, 2007, of approximately $43 million ($19 million on a Kansas jurisdictional basis) through the creation of a regulatory asset or liability, as appropriate; (ii) establishing, effective January 1, 2006, a regulatory asset or liability as appropriate for amounts arising from defined benefit plan settlements and curtailments which will be amortized over a five-year period beginning with the effective date of rates approved in KCP&L's next rate case; (iii) setting at 8.5% the equity rate for the equity component of the allowance for funds used during construction rate calculation for Iatan No. 2; and (iv) the filing by KCP&L of an ECA clause in its next rate case, to be filed no later than March 1, 2007.

KCP&L Regulatory Plan Appeals

On March 28, 2005, and April 27, 2005, KCP&L filed Stipulations and Agreements with the MPSC and KCC, respectively, containing a regulatory plan and other provisions. Parties to the MPSC Stipulation and Agreement are KCP&L, the Staff of the MPSC, the City of Kansas City, Missouri, Office of Public Counsel, Praxair, Inc., Missouri Industrial Energy Consumers, Ford Motor Company, Aquila, Inc., The Empire District Electric Company, Missouri Joint Municipal Electric Utility Commission and the Missouri Department of Natural Resources. Parties to the KCC Stipulation and Agreement are KCP&L, the Staff of the KCC, Sprint Nextel Corporation and the Kansas Hospital Association.

The MPSC issued its Report and Order, approving the Stipulation and Agreement, on July 28, 2005, and KCC issued its Order Approving Stipulation and Agreement on August 5, 2005. On September 22, 2005, the Sierra Club and Concerned Citizens of Platte County, two nonprofit corporations, filed a petition for review in the Circuit Court of Cole County, Missouri, seeking to review and set aside the MPSC Report and Order. On March 13, 2006, the Circuit Court affirmed the MPSC Report and Order, and the Sierra Club and Concerned Citizens of Platte County appealed to the Missouri Court of Appeals for the Western District. On October 21, 2005, the Sierra Club filed a petition for review in the District Court of Shawnee County, Kansas, seeking to set aside or remand KCC order. On May 1, 2006, the District Court denied the petition, and the Sierra Club appealed to the Kansas Court of Appeals. Although subject to the appeals, the MPSC and KCC orders remain in effect pending the courts' decisions.

Kansas City Power & Light Company v. Union Pacific Railroad Company

On October 12, 2005, KCP&L filed a rate complaint case with the Surface Transportation Board (STB) charging that Union Pacific Railroad Company's (Union Pacific) rates for transporting coal from the PRB in Wyoming to KCP&L's Montrose Station are unreasonably high. Prior to the end of 2005, the rates were established under a contract with Union Pacific. Efforts to extend the term of the contract were unsuccessful and Union Pacific is the only service for coal transportation from the PRB to Montrose Station. KCP&L charged that Union Pacific possesses market dominance over the traffic and requested the STB prescribe maximum reasonable rates.

In February 2006, the STB instituted a rulemaking to address issues regarding the cost test used in rail rate cases and the proper calculation of rail rate relief. As part of that order, the STB delayed hearing KCP&L's case pending the outcome of the rulemaking, and declared that the results of the rulemaking would apply to KCP&L's test. On October 30, 2006, the STB issued its decision, adopting the proposals set out in its rulemaking. This decision has been appealed by other parties to the Federal Circuit Court of Appeals for the District of Columbia. In July 2006, the STB directed KCP&L and Union Pacific to file comments in September 2006 on whether KCP&L's complaint is within the STB's jurisdiction. If the STB determines it does have jurisdiction, KCP&L anticipates a ruling on its case in

the second half of 2008. Until the STB case is decided, KCP&L is paying the higher tariff rates subject to refund.

Hawthorn No. 5 Litigation
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 Fire Insurance Company of Pittsburgh, Pennsylvania (National Union) and Reliance National Insurance had issued a $200 million primary insurance policy and Travelers Indemnity Company of Illinois (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. KCP&L filed suit against these two insurers, which was settled with the payment of the policy limit of the primary insurance policy (less the deductible amount), and with a $10 million payment by Travelers under its insurance policy.

KCP&L also filed suit in 2001 against multiple defendants who were alleged to have responsibility for the Hawthorn No. 5 boiler explosion. KCP&L and National Union entered into a subrogation allocation agreement under which recoveries in this suit were generally allocated 55% to National Union and 45% to KCP&L. Various defendants settled with KCP&L, and KCP&L received a judgment against the final remaining defendant in 2006. In 2005, Travelers filed suit against National Union in the U.S. District Court for the Eastern District of Missouri, asserting that it was entitled to reimbursement or subrogation for the $10 million it paid to KCP&L from money recovered by KCP&L and National Union in the subrogation case. On June 19, 2006, KCP&L was added as a defendant to this case. The case was subsequently transferred to, and is pending in, the U.S. District Court for the Western District of Missouri.

Iatan Station Air Permit
On January 31, 2006, the Missouri Department of Natural Resources issued an air permit to KCP&L for the construction of Iatan No. 2 and modifications to Iatan No. 1. The Sierra Club appealed the issuance of this permit to the Missouri Air Conservation Commission, and on September 29, 2006, filed a motion requesting that construction work on Iatan No. 2 be stayed during the pendency of the appeal. The motion was denied on October 18, 2006. A hearing on this appeal has been scheduled for March 2007. The permit remains in effect pending the outcome of the appeal.

Weinstein v. KLT Telecom
Richard D. Weinstein (Weinstein) filed suit against KLT Telecom Inc. (KLT Telecom) in September 2003 in the St. Louis County, Missouri Circuit Court. KLT Telecom acquired a controlling interest in DTI Holdings, Inc. (Holdings) in February 2001 through the purchase of approximately two-thirds of the Holdings stock held by Weinstein. In connection with that purchase, KLT Telecom entered into a put option in favor of Weinstein, which granted Weinstein an option to sell to KLT Telecom his remaining shares of Holdings stock. The put option provided for an aggregate exercise price for the remaining shares equal to their fair market value with an aggregate floor amount of $15 million and was exercisable between September 1, 2003, and August 31, 2005. In June 2003, the stock of Holdings was cancelled and extinguished pursuant to the joint Chapter 11 plan confirmed by the Bankruptcy Court. In September 2003, Weinstein delivered a notice of exercise of his claimed rights under the put option. KLT Telecom rejected the notice of exercise, and Weinstein filed suit alleging breach of contract. Weinstein sought damages of at least $15 million, plus statutory interest. In April 2005, summary judgment was granted in favor of KLT Telecom, and Weinstein appealed this judgment to the Missouri Court of Appeals for the Eastern District. On May 16, 2006, the Court of Appeals affirmed the judgment. Weinstein filed a motion for transfer of this case to the Missouri Supreme Court, which was granted. Oral arguments have been held and the case is pending the decision of the court. The $15 million reserve has not been reversed pending the outcome of the appeal process.

Tech Met, Inc., et al. v. Strategic Energy
On November 21, 2005, a class action complaint for breach of contract was filed against Strategic Energy in the Court of Common Pleas of Allegheny County, Pennsylvania. The five named plaintiffs purportedly represent the interests of customers in Pennsylvania who entered into Power Supply Coordination Service Agreements (Agreement) for electricity service. The complaint seeks monetary damages, attorney fees and costs and a declaration that the customers may terminate their Agreement with Strategic Energy. In response to Strategic Energy's preliminary objections, the plaintiffs have filed an amended complaint. Strategic Energy has been granted an indefinite period of time to respond to this amended complaint.

Other Proceedings
The companies are parties to various other lawsuits and regulatory proceedings in the ordinary course of their respective businesses. For information regarding other lawsuits and proceedings, see Notes 5, 13 and 15 to the consolidated financial statements. Such descriptions are incorporated herein by reference.

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

During the fourth quarter of 2006, no matter was submitted to a vote of security holders through the solicitation of proxies or otherwise for either Great Plains Energy or KCP&L.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

GREAT PLAINS ENERGY
Great Plains Energy common stock is listed on the New York Stock Exchange under the symbol GXP. At February 21, 2007, Great Plains Energy's common stock was held by 13,249 shareholders of record. Information relating to market prices and cash dividends on Great Plains Energy's common stock is set forth in the following table.

	Common Stock Price Range				Common Stock Dividends Declared		
	2006		2005				
Quarter	High	Low	High	Low	2007	2006	2005
First	$ 29.32	$ 27.89	$ 31.61	$ 29.56	$ 0.415 [a]	$ 0.415	$ 0.415
Second	28.99	27.33	32.25	29.77		0.415	0.415
Third	31.43	27.70	32.63	29.82		0.415	0.415
Fourth	32.80	31.13	30.23	27.27		0.415	0.415

[a] Declared February 6, 2007.

Regulatory Restrictions
Under stipulations with the MPSC and KCC, Great Plains Energy has committed to maintain consolidated common equity of not less than 30%.

Dividend Restrictions
Great Plains Energy's Articles of Incorporation contain certain restrictions on the payment of dividends on Great Plains Energy's common stock 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 members to the Board of Directors.

Equity Compensation Plan

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 following table provides information, as of December 31, 2006, regarding the number of common shares to be issued upon exercise of outstanding options, warrants and rights, their weighted average exercise price, and the number of shares of common stock remaining available for future issuance under the Long-Term Incentive Plan. The table excludes shares issued or issuable under Great Plains Energy's defined contribution savings plans.

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	364,183 [1]	$ 25.52 [2]	1,878,929
Equity compensation plans not approved by security holders	-	-	-
Total	364,183	$ 25.52	1,878,929

(1) Includes 254,711 performance shares at target performance levels and options for 109,472 shares of Great Plains Energy common stock outstanding at December 31, 2006.

(2) The 254,711 performance shares have no exercise price and therefore are not reflected in the weighted average exercise price.

Purchases of Equity Securities
The following table provides information regarding purchases by the Company of its equity securities during the fourth quarter of 2006.

Issuer Purchases of Equity Securities				
Month	Total Number of Shares (or Units) Purchased	Average Price Paid per Share (or Unit)	Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs
October 1 - 31	4,777 [1]	$31.12	-	N/A
November 1 - 30	3,042 [1]	32.18	-	N/A
December 1 - 31	-	-	-	N/A
Total	7,819	$31.53	-	N/A

[1] Represents shares of common stock surrendered to the Company by certain officers to pay taxes related to the vesting of restricted common stock.

KCP&L
KCP&L is a wholly owned subsidiary of Great Plains Energy, which holds the one share of issued and outstanding KCP&L common stock.

Regulatory Restrictions
Under the Federal Power Act, KCP&L can pay dividends only out of retained or current earnings. Under stipulations with the MPSC and KCC, KCP&L has committed to maintain consolidated common equity of not less than 35%.

Equity Compensation Plan
KCP&L does not have an equity compensation plan; however, KCP&L officers participate in Great Plains Energy's Long-Term Incentive Plan.

ITEM 6. SELECTED FINANCIAL DATA

Year Ended December 31	2006	As Adjusted 2005 [d]	As Adjusted 2004 [d]	As Adjusted 2003 [d]	As Adjusted 2002 [d]
Great Plains Energy [a]		(dollars in millions except per share amounts)			
Operating revenues	$ 2,675	$ 2,605	$ 2,464	$ 2,148	$ 1,802
Income from continuing operations [b]	$ 128	$ 164	$ 175	$ 189	$ 136
Net income	$ 128	$ 162	$ 183	$ 144	$ 125
Basic earnings per common share from continuing operations	$ 1.62	$ 2.18	$ 2.41	$ 2.71	$ 2.15
Basic earnings per common share	$ 1.62	$ 2.15	$ 2.51	$ 2.06	$ 1.98
Diluted earnings per common share from continuing operations	$ 1.61	$ 2.18	$ 2.41	$ 2.71	$ 2.15
Diluted earnings per common share	$ 1.61	$ 2.15	$ 2.51	$ 2.06	$ 1.98
Total assets at year end	$ 4,336	$ 3,842	$ 3,796	$ 3,694	$ 3,521
Total redeemable preferred stock, mandatorily redeemable preferred securities and long-term debt (including current maturities)	$ 1,142	$ 1,143	$ 1,296	$ 1,347	$ 1,332
Cash dividends per common share	$ 1.66	$ 1.66	$ 1.66	$ 1.66	$ 1.66
SEC ratio of earnings to fixed charges	3.20	3.60	3.54	4.22	2.98
Consolidated KCP&L [a]					
Operating revenues	$ 1,140	$ 1,131	$ 1,092	$ 1,057	$ 1,013
Income from continuing operations [c]	$ 149	$ 144	$ 145	$ 125	$ 102
Net income	$ 149	$ 144	$ 145	$ 116	$ 95
Total assets at year end	$ 3,859	$ 3,340	$ 3,335	$ 3,315	$ 3,143
Total redeemable preferred stock, mandatorily redeemable preferred securities and long-term debt (including current maturities)	$ 977	$ 976	$ 1,126	$ 1,336	$ 1,313
SEC ratio of earnings to fixed charges	4.11	3.87	3.37	3.68	2.87

(a) Great Plains Energy's and KCP&L's consolidated financial statements include results for all subsidiaries in operation for the periods presented.

(b) This amount is before discontinued operations of $(1.9), $7.3, $(44.8) and $(7.5) in 2005 through 2002, respectively. In 2002, this amount is before a $3.0 million cumulative effect of a change in accounting principle.

(c) This amount is before discontinued operations of $(8.7) and $(4.0) million in 2003 and 2002. In 2002, this amount is before a $3.0 million cumulative effect of a change in accounting principle.

(d) See Note 5 to the consolidated financial statements for information regarding Wolf Creek refueling outage costs and an associated change in accounting principle.

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

The MD&A that follows is 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.

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

Executive Summary

Great Plains Energy's 2006 earnings were characterized by higher fuel costs, lower prices for wholesale sales and coal conservation in the first half of the year, partially offset by lower purchased power expense and higher retail revenue at KCP&L, as well as higher average retail gross margins per MWh without the impact of unrealized fair value gains and losses at Strategic Energy. Earnings for 2006 also reflect the absence of tax benefits experienced at KCP&L in 2005 and lower delivered volumes at Strategic Energy.

In 2006, KCP&L completed the Spearville Wind Energy Facility and received rate orders from the MPSC and KCC. KCP&L began construction of Iatan No.2, continued to make progress on environmental upgrades at existing facilities and implemented customer affordability and efficiency programs.

Anticipated Acquisition of Aquila, Inc.

In February 2007, Great Plains Energy entered into an agreement to acquire Aquila. Immediately prior to Great Plains Energy's acquisition of Aquila, Black Hills Corporation will acquire Aquila's electric utility in Colorado and its gas utilities in Colorado, Kansas, Nebraska and Iowa plus associated liabilities for a total of $940 million in cash, subject to closing adjustments. Each of the two transactions is conditioned on the completion of the other transaction and is expected to close in 2008. Management believes the anticipated acquisition will allow Great Plains Energy to expand its operations in a manner consistent with its strategic intent. Great Plains Energy entered into the transaction agreements with the expectation that the acquisition would result in various benefits to it and KCP&L including, among other things, synergies, cost savings and operating efficiencies. Assuming that such efficiencies are achieved and taking into account the anticipated cost of achieving such synergies, the transaction is expected to be modestly dilutive to earnings per share in 2008 and accretive beginning in 2009. See Note 3 to the consolidated financial statements for additional information.

EXECUTING ON STRATEGIC INTENT

KCP&L's Comprehensive Energy Plan

KCP&L continues to make progress in implementing its comprehensive energy plan under orders received from the MPSC and KCC in 2005. During 2006, KCP&L completed the Spearville Wind Energy Facility, a 100.5 MW wind project in western Kansas. KCP&L also entered into certain procurement and engineering agreements for other comprehensive energy plan projects, and further refined its cost estimates and schedules as contracting and engineering progressed. See Note 6 to the consolidated financial statements for the comprehensive energy plan estimated capital expenditures by project.

The estimated capital expenditures include prices for labor and materials that reflect current and expected market conditions. They also include contingencies that reflect, among other things, the currently foreseen risks of those future market conditions as well as risks associated with global sourcing of materials. The demand for environmental projects has increased substantially, with many utilities in the United States starting similar projects to address changing environmental regulations. This demand has constrained labor and material resources resulting in a significant escalation in the cost of, and extension of scheduled completion times for, environmental retrofits. Because of the magnitude of the comprehensive energy plan projects and the length of the implementation period, the actual expenditures, scope and timing of any or all of these projects that have not been completed may differ materially from these estimates.

Construction of Iatan No. 2 is underway and on schedule for completion in 2010. KCP&L has approximately 50% of the total estimated cost of the project under firm contracts. The estimated range of capital expenditures for Iatan No. 2 includes items that are customarily excluded in calculating the installed cost per KW of a generating plant such as rail cars, substation expansion, interconnection upgrades, off-site improvements, solid waste landfill and operating spare parts. Excluding these items, the currently estimated installed cost for Iatan No. 2 ranges from approximately $1,700/KW to $1,875/KW, which KCP&L management believes is competitive with other similar projects to be built in the same timeframe.

The first phase of environmental upgrades at LaCygne No. 1, installation of selective catalytic reduction equipment, began in late 2005 and is expected to be in-service for the summer of 2007. KCP&L has almost all of the total estimated cost for the first phase under firm contract. The second phase of environmental upgrades at LaCygne No. 1 is expected to start design in 2007, and the market conditions noted above could impact the scope and timing. Iatan No. 1 environmental upgrades are on schedule with approximately 70% of the total estimated costs under firm contract.

In 2006, KCP&L implemented several pilot affordability, energy efficiency and demand response programs in Missouri and Kansas as well as distribution automation system improvements. Results from the implemented pilot programs have demonstrated an ability to manage KCP&L's customers' retail load requirements and by the end of 2006, KCP&L had developed the capability to effect a 60 MW reduction in retail load requirements. These results are evidenced by the success of KCP&L's Energy Optimizer (a residential air conditioning cycling program), MPower (a commercial/industrial curtailment program) and distribution automation investments such as dynamic voltage control. Additionally in 2006, KCC initiated a general investigation into strategies for improving energy efficiency. The general issues that KCC is investigating relates to when and how utilities should promote energy efficiency by their customers and what ratemaking treatment, including special mechanisms, is appropriate or desirable. This investigation provides a significant opportunity for the continued development of policies and regulations in Kansas designed to promote energy efficiency.

KCP&L Regulatory Proceedings

In December 2006, KCP&L received rate orders from the MPSC and KCC authorizing annual rate increases of $51 million and $29 million, respectively. The ordered rates were implemented January 1, 2007. See Note 6 to the consolidated financial statements for additional information. In February 2007, KCP&L filed a request with the MPSC for an annual rate increase of approximately $45 million. KCP&L is required to file a rate request with KCC on March 1, 2007.

KCP&L BUSINESS OVERVIEW

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 electricity to over 505,000 customers in the states of

Missouri and Kansas. KCP&L has continued to experience modest load growth. Load growth consists of higher usage per customer and the addition of new customers. Retail electricity rates are below the national average.

KCP&L's residential customers' usage is significantly affected by weather. 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. Less than 1% of revenues include an automatic fuel adjustment provision. KCP&L's coal base load equivalent availability factor was 83% in 2006 compared to 82% in 2005.

KCP&L's nuclear unit, Wolf Creek, accounts for approximately 20% of its base load capacity. In 2006, WCNOC submitted an application for a new operating license for Wolf Creek with the NRC, which would extend Wolf Creek's operating period to 2045. The NRC may take up to two years to rule on the application. Wolf Creek's most recent refueling outage was in October 2006 and lasted 35 days. The next refueling outage is scheduled to begin in March 2008. In 2006, KCP&L changed the method of accounting for the Wolf Creek refueling outage and retrospectively adjusted prior periods. See Note 5 to the consolidated financial statements for additional information.

The fuel cost per MWh generated and the purchased power cost per MWh have a significant impact on the results of operations for KCP&L. Generation fuel mix can substantially change the fuel cost per MWh generated. Nuclear fuel cost per MWh generated is substantially less than the cost of coal per MWh generated, which is significantly lower than the cost of natural gas and oil per MWh generated. The cost per MWh for purchased power is generally significantly higher than the 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 and purchased power, and the requirements of other electric systems to provide reliable power economically.

Management expects its cost of nuclear fuel to remain relatively stable through 2009 because of contracts in place. Between 2010 and 2018, management anticipates the cost of nuclear fuel to increase approximately 30% to 50% due to higher contracted prices and market conditions. Even with this anticipated increase, management expects nuclear fuel cost per MWh generated to remain less than the cost of other fuel sources.

Approximately 98% of KCP&L's coal requirements come from the PRB and are transported on the Burlington Northern Santa Fe and the Union Pacific railroads, both of which had experienced longer cycle times for coal deliveries in 2004 and 2005. In 2006, KCP&L's coal shipments improved significantly, inventory levels improved and KCP&L suspended its coal conservation measures implemented in 2005. Management continues to monitor the situation closely and steps will be taken, as necessary, to maintain an adequate energy supply for KCP&L's retail load and firm MWh sales. However, an inability to obtain timely delivery of coal to meet generation requirements in the future could materially impact KCP&L's results of operations by increasing its cost to serve its retail customers and/or reducing wholesale MWh sales.

STRATEGIC ENERGY BUSINESS OVERVIEW

Great Plains Energy indirectly owns 100% of Strategic Energy. Strategic Energy does not own any generation, transmission or distribution facilities. Strategic Energy provides competitive retail electricity supply services by entering into power supply contracts to supply electricity to its end-use customers. Of the states that offer retail choice, Strategic Energy operates in California, Illinois, Maryland, Massachusetts, Michigan, New Jersey, New York, Ohio, Pennsylvania and Texas. Strategic Energy has begun expansion into Connecticut.

In addition to competitive retail electricity supply services, Strategic Energy also provides strategic planning, consulting and billing and scheduling services in the natural gas and electricity markets. The cost of supplying electric service to retail customers can vary widely by geographic market. This variability can be affected by many factors, including, but not limited to, geographic differences in the cost per MWh of purchased power, renewable energy requirements and capacity charges due to regional purchased power availability and requirements of other electricity providers and differences in transmission charges.

Strategic Energy provides services to approximately 88,200 commercial, institutional and small manufacturing accounts for approximately 25,000 customers including numerous Fortune 500 companies, smaller companies and governmental entities. Strategic Energy offers an array of products designed to meet the various requirements of a diverse customer base including fixed price, index-based and month-to-month renewal products. Strategic Energy's volume-based customer retention rate, excluding month-to-month customers on market-based rates for 2006 was 61%. The corresponding volume-based customer retention rates including month-to-month customers on market-based rates was 71%. Retention rates for 2006 were lower than Strategic Energy has experienced in recent years. The decline is attributable to customer contract expirations in midwestern states where the savings competitive suppliers can offer to customers are limited or in some cases unavailable due to host utility default rates that are not aligned with market prices for power. In these states, customers can receive lower rates from the host utility and are choosing to return to host utility service as their contracts with Strategic Energy expire. Management expects to have continued difficulty competing in these states until more competitive market-driven pricing mechanisms are in place or market prices for power decrease below host utility rates.

Management has focused sales and marketing efforts on states that currently provide a more competitive pricing environment in relation to host utility default rates. In these states, Strategic Energy continues to experience improvement in certain key metrics, including strong forecasted future MWh commitments (backlog) growth and longer contract durations. As a result, total backlog grew to 32.8 million MWh at December 31, 2006, compared to 18.3 million MWh at December 31, 2005. Average contract durations grew to 18 months in 2006 from 17 months in 2005. Based solely on expected MWh usage under current signed contracts, Strategic Energy has backlog of 14.7 million MWh, 8.9 million MWh and 4.1 million MWh for the years 2007 through 2009, respectively, and 5.1 million MWh over the years 2010 through 2012. Strategic Energy's projected MWh deliveries for 2007 are in the range of 18 to 22 million MWhs. Strategic Energy expects to deliver additional MWhs above amounts currently in backlog through new and renewed term contracts and MWh deliveries to month-to-month customers.

Strategic Energy currently expects the average retail gross margin per MWh (retail revenues less retail purchased power divided by retail MWhs delivered) delivered in 2007 to average $4.35 to $5.35. This range excludes unrealized changes in fair value of non-hedging energy contracts and from hedge ineffectiveness because management does not predict the future impact of these unrealized changes. Actual retail gross margin per MWh may differ from these estimates.

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 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. Management has identified the following accounting policies deemed critical to the understanding of the companies' results of operations and financial position. Management has discussed the development and selection of these critical accounting policies with the Audit Committee of the Board of Directors.

Pensions

The companies incur 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 actuarial assumptions are updated annually at the beginning of the plan year. 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 management's best estimates and judgment; however, material changes may occur if these assumptions differ from actual events. See Note 8 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% increase or a 0.5% decrease in key actuarial assumptions. Each sensitivity reflects the impact of the change based on a change in that assumption only.

Actuarial assumption	Change in Assumption	Impact on Projected Benefit Obligation	Impact on 2006 Pension Expense
		(millions)	
Discount rate	0.5% increase	$ (34.1)	$ (2.9)
Rate of return on plan assets	0.5% increase	-	(1.8)
Discount rate	0.5% decrease	36.2	3.0
Rate of return on plan assets	0.5% decrease	-	1.8

KCP&L recorded pension expense reflecting orders from the MPSC and KCC that established annual pension costs at $22 million for 2006 and 2005. Expected 2007 pension expense will approximate $35 million after allocations to the other joint owners of generating facilities and capitalized amounts consistent with the December 2006 MPSC and KCC rate orders. The difference between pension costs under SFAS No. 87, "Employers' Accounting for Pensions" and SFAS No. 88, "Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits" and the amount allowed for ratemaking is recorded as a regulatory asset or liability for future ratemaking recovery or refunds, as appropriate. See Note 8 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, changes in pension liability and cash funding requirements due to volatile market conditions.

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 otherwise be recorded under GAAP. Regulatory assets represent incurred costs that are probable of recovery from future revenues. Regulatory liabilities represent amounts imposed by rate actions of KCP&L's regulators that may require refunds to customers, represent amounts provided in current rates that are intended to recover costs that are expected to be incurred in the future for which KCP&L remains accountable, or represent a gain or other reduction of allowable costs to be given to customers over future periods. Future recovery of regulatory assets is not assured, but is generally subject to review by regulators in rate proceedings for matters such as prudence and reasonableness. Future reductions in revenue or refunds for regulatory liabilities generally are not mandated, pending future rate proceedings or actions by the regulators. Management regularly assesses whether regulatory assets and liabilities are probable of future recovery or refund by considering factors such as decisions by the MPSC, KCC or FERC on KCP&L's rate case filings; decisions in other regulatory proceedings, including decisions related to other companies that establish precedent on matters applicable to KCP&L; and changes in laws and regulations. If recovery or refund of regulatory assets or liabilities is not approved by regulators or is no longer deemed probable, these regulatory assets or liabilities are recognized in the current period results of operations. KCP&L's continued ability to meet the criteria for application of SFAS No. 71 may be affected in the future by restructuring and deregulation in the electric industry. In the event that SFAS No. 71 no longer applied to a deregulated 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 6 to the consolidated financial statements for more information.

Energy and Energy-Related Contract Accounting

Strategic Energy generally purchases power under forward physical delivery contracts to supply electricity to its retail energy customers under full requirement sales contracts. The full requirements sales contracts and the forward physical delivery contracts meet the accounting definition of a derivative; however, Strategic Energy applies the normal purchases and normal sales (NPNS) exception accounting treatment on full requirement sales contracts. Derivative contracts designated as NPNS are accounted for by accrual accounting, which requires the effects of the derivative to be recorded when the underlying contract settles.

Strategic Energy has historically designated the majority of the forward physical delivery contracts as NPNS; however, as certain markets continue to develop, some derivative instruments may no longer qualify for the NPNS exception. As such, Strategic Energy is designating these forward physical delivery contracts as cash flow hedges, which could result in future increased volatility in derivative assets and liabilities, other comprehensive income (OCI) and net income. 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 to purchased power expense in Great Plains Energy's consolidated statement of income as the power is delivered and/or the contract settles. Accordingly, the increase in derivatives accounted for as cash flow hedges and the corresponding decrease in derivatives accounted for as NPNS transactions may affect the timing and nature of accounting recognition, but does not change the underlying economic results.

The fair value of forward purchase derivative contracts that do not meet the requirements for the NPNS exception or cash flow hedge accounting are recorded as current or long-term derivative assets or liabilities. Changes in the fair value of these contracts could result in operating income volatility as changes in the associated derivative assets and liabilities are recorded in purchased power expense in Great Plains Energy's consolidated statement of income.

Strategic Energy's 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. Future market prices may vary from those used in recording energy assets and liabilities at fair value and 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. Management 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.

	2006	As Adjusted 2005	As Adjusted 2004
		(millions)	
Operating revenues	$ 2,675.3	$ 2,604.9	$ 2,464.0
Fuel	(229.5)	(208.4)	(176.8)
Purchased power	(1,516.7)	(1,429.7)	(1,300.0)
Skill set realignment costs	(9.4)	-	-
Other operating expenses	(524.4)	(527.2)	(510.5)
Depreciation and amortization	(160.5)	(153.1)	(150.1)
Gain (loss) on property	0.6	(3.5)	(5.1)
Operating income	235.4	283.0	321.5
Non-operating income (expenses)	13.2	2.7	(8.4)
Interest charges	(71.2)	(73.8)	(83.0)
Income taxes	(47.9)	(39.5)	(55.5)
Minority interest in subsidiaries	-	(7.8)	2.1
Loss from equity investments	(1.9)	(0.4)	(1.5)
Income from continuing operations	127.6	164.2	175.2
Discontinued operations	-	(1.9)	7.3
Net income	127.6	162.3	182.5
Preferred dividends	(1.6)	(1.6)	(1.6)
Earnings available for common shareholders	$ 126.0	$ 160.7	$ 180.9

2006 compared to 2005
Great Plains Energy's 2006 earnings available for common shareholders decreased to $126.0 million, or $1.61 per diluted share, from $160.7 million, or $2.15 per share, in 2005. A higher average number of common shares, primarily due to the issuance of 5.2 million shares in May 2006, diluted 2006 earnings per share by $0.08.

Consolidated KCP&L's net income increased $5.6 million in 2006 compared to 2005 due to increased retail revenues and decreased purchase power expense. These increases to net income were partially offset by costs related to skill set realignments, increased fuel expense and higher income taxes due to higher pre-tax income in 2006 and a decrease in 2005 income taxes reflecting a reduction in KCP&L's deferred tax balances as a result of a reduction in KCP&L's composite tax rate.

Strategic Energy had a net loss of $9.9 million in 2006 compared to net income of $28.2 million in 2005. The net loss was primarily the result of the after tax impact of $33.4 million in changes in fair value related to non-hedging energy contracts and from cash flow hedge ineffectiveness. Additionally, retail MWhs delivered decreased 15% in 2006 compared to 2005 but the impact to net income was partially offset by higher average retail gross margins per MWh without the impact of unrealized fair value gains and losses.

2005 compared to 2004
Great Plains Energy's 2005 earnings available for common shareholders decreased to $160.7 million, or $2.15 per share, from $180.9 million, or $2.51 per share in 2004. A higher average number of common shares diluted 2005 EPS by $0.08 primarily due to the issuance of 5.0 million shares in June 2004.

Consolidated KCP&L's net income was relatively unchanged in 2005 compared to 2004. KCP&L's net income decreased $6.5 million primarily due to higher fuel costs and purchased power prices, as well as the effects of plant outages and coal conservation on fuel mix. Higher other operating expenses were partially offset by the regulatory accounting treatment of pension expense. These decreases to net income were offset by retail revenues increasing 6% as a result of significantly warmer summer weather in 2005 compared to an unusually mild summer in 2004. Additionally, the favorable impact of sustained audit positions on the 2005 composite tax rates lowered income taxes. KCP&L's decrease was partially offset by $5.2 million in reduced losses at HSS primarily due to a 2004 impairment charge related to the 2005 sale of Worry Free.

Strategic Energy's net income decreased $14.3 million in 2005 compared to 2004. Retail MWhs delivered decreased 4% in 2005 compared to 2004. The average retail gross margin per MWh declined 14% to $5.19 in 2005. The decline in average retail gross margin per MWh in 2005 compared to 2004 was primarily due to an environment of higher and less volatile energy prices, flat to higher forward electricity prices and 2005 SECA charges in excess of recoveries. The negative impacts on average retail gross margin per MWh were partially offset by two significant opportunities to manage retail portfolio load requirements, the favorable reduction of a gross receipts tax contingency and a favorable change in fair value related to non-hedging energy contracts and from cash flow hedge ineffectiveness. Strategic Energy's 2005 income taxes decreased due to lower taxable income partially offset by $3.2 million in lower tax benefits allocated from the holding company.

Higher reductions in affordable housing investments and lower related tax credits decreased other non-regulated operations net income in 2005 compared to 2004 by $5.5 million. Discontinued operations decreased net income $9.2 million in 2005 compared to 2004, primarily due to a 2004 gain on the sale of the majority of the KLT Gas natural gas properties (KLT Gas portfolio). This gain was partially offset by 2004 losses from the wind down operations and a loss due to the write down of the KLT Gas portfolio to its estimated net realizable value.

CONSOLIDATED KCP&L RESULTS OF OPERATIONS

The following discussion of consolidated KCP&L results of operations includes KCP&L, an integrated, regulated electric utility and HSS, an unregulated subsidiary of KCP&L. In the discussion that follows, references to KCP&L reflect only the operations of the utility. The following table summarizes consolidated KCP&L's comparative results of operations.

	2006	As Adjusted 2005	As Adjusted 2004
		(millions)	
Operating revenues	$ 1,140.4	$ 1,130.9	$ 1,091.6
Fuel	(229.5)	(208.4)	(176.8)
Purchased power	(26.4)	(61.3)	(52.5)
Skill set realignment costs	(9.3)	-	-
Other operating expenses	(452.1)	(460.5)	(442.2)
Depreciation and amortization	(152.7)	(146.6)	(145.2)
Gain (loss) on property	0.6	(4.6)	(5.1)
Operating income	271.0	249.5	269.8
Non-operating income (expenses)	9.6	11.8	(1.9)
Interest charges	(61.0)	(61.8)	(74.2)
Income taxes	(70.3)	(48.0)	(53.8)
Minority interest in subsidiaries	-	(7.8)	5.1
Net income	$ 149.3	$ 143.7	$ 145.0

Consolidated KCP&L Sales Revenues and MWh Sales

	2006	% Change	2005	% Change	2004
Retail revenues			(millions)		
Residential	$ 384.3	1	$ 380.0	9	$ 347.1
Commercial	442.6	2	434.6	3	421.1
Industrial	99.8	(1)	100.9	5	96.2
Other retail revenues	8.8	3	8.6	(2)	8.7
Total retail	935.5	1	924.1	6	873.1
Wholesale revenues	190.4	(1)	192.4	(4)	200.2
Other revenues	14.5	1	14.3	(15)	16.8
KCP&L electric revenues	1,140.4	1	1,130.8	4	1,090.1
Subsidiary revenues	-	NM	0.1	(93)	1.5
Consolidated KCP&L revenues	$ 1,140.4	-	$ 1,130.9	4	$ 1,091.6

	2006	% Change	2005	% Change	2004
Retail MWh sales			(thousands)		
Residential	5,413	1	5,383	10	4,903
Commercial	7,403	2	7,292	4	6,998
Industrial	2,148	(1)	2,165	5	2,058
Other retail MWh sales	86	4	82	(3)	85
Total retail	15,050	1	14,922	6	14,044
Wholesale MWh sales	4,676	1	4,608	(30)	6,603
KCP&L electric MWh sales	19,726	1	19,530	(5)	20,647

Retail revenues increased $11.4 million in 2006 compared to 2005 primarily due to weather normalized load growth of over 1% slightly offset by the impact of weather with favorable summer weather being more than offset by mild winter weather.

Retail revenues increased $51.0 million in 2005 compared to 2004. The increase was driven by significantly warmer summer weather in 2005 compared to an unusually mild summer in 2004 and continued weather normalized load growth of approximately 2% in 2005. Residential usage per customer increased 9% in 2005, driven by a 45% increase in cooling degree days, which was 19% above normal.

The following table provides cooling degree days (CDD) and heating degree days (HDD) for the last three years at Kansas City International Airport. CDD and HDD are used to reflect the demand for energy to cool or heat homes and buildings.

	2006	% Change	2005	% Change	2004
CDD	1,724	6	1,626	45	1,118
HDD	4,052	(15)	4,780	1	4,741

Wholesale revenues decreased $2.0 million in 2006 compared to 2005 due to an 11% decrease in the average market price per MWh to $42.52 partially offset by a 1% increase in wholesale MWh sales. The decrease in average market price per MWh was primarily due to lower gas prices in 2006 compared to 2005, as well as the effects on 2005 average prices from coal conservation in the region. Additionally, wholesale revenues for 2006 include $2.5 million in litigation recoveries for the loss of use of Hawthorn No. 5 from a 1999 boiler explosion.

Wholesale revenues decreased $7.8 million in 2005 compared to 2004 due to a 30% decrease in MWhs sold, which was significantly offset by an increase in the average market price per MWh. The decrease in MWhs sold was driven by a 5% decrease in net MWhs generated as a result of coal conservation and plant outages. Additionally, retail MWh sales increased 6% in 2005 compared to 2004, which resulted in less MWhs available for wholesale sales. Average market price per MWh increased 56% to $47.82 in 2005 compared to 2004 due to warmer summer weather in 2005, higher natural gas prices, transmission constraints and coal conservation in the region.

Consolidated KCP&L Fuel and Purchased Power

Net MWhs Generated by Type	2006	% Change	2005	% Change	2004
			(thousands)		
Coal	15,056	-	14,994	(4)	15,688
Nuclear	4,395	6	4,146	(13)	4,762
Natural gas and oil	564	19	473	206	155
Wind	106	N/A	-	-	-
Total Generation	20,121	3	19,613	(5)	20,605

Fuel expense increased $21.1 million in 2006 compared to 2005 due to a 2% increase in MWhs generated, excluding wind generation, which has no fuel cost, increased coal and coal transportation costs and more natural gas generation in the fuel mix, which has higher costs compared to other fuel types. These increases were partially offset by lower natural gas prices and $3.7 million in Hawthorn No. 5 litigation recoveries. KCP&L's current coal and coal transportation contracts include higher tariff rates being charged by Union Pacific. KCP&L has filed a rate case complaint against Union Pacific with the STB and until the case is finalized, KCP&L is paying the tariff rates subject to refund. See Note 15 to the consolidated financial statements for more information.

Fuel expense increased $31.6 million in 2005 compared to 2004 despite a 5% decrease in MWhs generated due to a combination of changes in the fuel mix to higher cost generation, increased coal and coal transportation costs and increased natural gas prices. The changes in fuel mix were driven by the number and duration of plant outages as well as coal conservation measures. KCP&L's 2005 coal and coal transportation contracts were entered into at higher average prices than related 2004 contracts.

Purchased power expense decreased $34.9 million in 2006 compared to 2005. The decreases were primarily due to recording $10.8 million in Hawthorn No. 5 litigation recoveries as a reduction in purchased power expense and a 40% reduction in MWhs purchased. The reduction in MWhs purchased was due to uneconomical purchased power prices and increased net MWhs generated. In addition, capacity payments decreased $5.1 million in 2006 due to the expiration of two large contracts in the second quarter of 2005. KCP&L entered into new capacity contracts in June 2006.

Purchased power expense increased $8.8 million in 2005 compared to 2004. The average price per MWh purchased increased 61% in 2005 compared to 2004 partially offset by an 8% decline in MWhs purchased. The increased prices were driven by purchases during higher priced peak hours as a result of warmer weather, plant outages and overall higher average prices due to higher natural gas prices combined with transmission constraints, coal conservation and outages in the region.

Consolidated KCP&L Other Operating Expenses *(including other operating, maintenance and general taxes)*

Consolidated KCP&L's other operating expenses decreased $8.4 million in 2006 compared to 2005 primarily due to the following:

- decreased severance and incentive compensation expense of $6.3 million,
- decreased restoration expenses of $5.1 million due to expenses that were incurred for a January 2005 ice storm and a June 2005 wind storm,
- deferring $6.2 million of expenses in accordance with MPSC and KCC orders.

Partially offsetting the decrease in other operating expenses was:

- increased maintenance expenses of $2.6 million for facilities, software and communication equipment and
- increased property taxes of $2.7 million primarily due to increases in assessed property valuations and mill levies.

Consolidated KCP&L's other operating expenses increased $18.3 million in 2005 compared to 2004 primarily due to the following:

- increased employee-related expenses of $4.7 million including severance and incentive compensation,
- increased expenses of $2.4 million due to higher legal reserves,
- increased regulatory expenses of $1.2 million including expenses related to the comprehensive energy plan,
- increased general taxes of $5.9 million primarily due to increases in gross receipts tax, assessed property valuations and mill levies,
- increased expenses of $4.2 million due to higher restoration costs for a January 2005 ice storm and June 2005 wind storms compared to the 2004 wind storm restoration costs and
- increased production operations and maintenance expenses of $4.1 million primarily due to scheduled and forced plant maintenance in 2005 and the reversal of an environmental accrual in 2004.

Partially offsetting the increase in other operating expenses was:

- decreased pension expense of $4.7 million due to the regulatory accounting treatment of pension expense in accordance with MPSC and KCC orders and
- decreased transmission service expense of $5.7 million primarily due to lower wholesale MWhs sold.

Consolidated KCP&L Skill Set Realignment Costs
In 2005 and early 2006, management undertook a process to assess, improve and reposition the skill sets of employees for implementation of the comprehensive energy plan. KCP&L recorded $9.3 million in 2006 related to this workforce realignment process reflecting severance, benefits and related payroll taxes provided by KCP&L to employees. In its 2007 rate cases, KCP&L is requesting to establish a regulatory asset for these costs and amortize them over five years effective with new rates on January 1, 2008.

Consolidated KCP&L Gain (loss) on Property
During 2005, KCP&L wrote off $3.6 million of plant operating system development costs at Wolf Creek as a result of vendor non-performance. In 2004, HSS recorded a $7.3 million impairment charge related to the sale of its subsidiary Worry Free.

Consolidated KCP&L Interest Charges
Consolidated KCP&L's interest charges decreased $12.4 million in 2005 compared to 2004 primarily due to $10.1 million of interest related to the IRS 1995-1999 audit settlement in 2004.

Consolidated KCP&L Income Taxes
Consolidated KCP&L's income taxes increased $22.3 million in 2006 compared to 2005 due to an increase in pre-tax income in 2006 and a decrease in 2005 of $11.7 million due to the impact of a lower composite tax rate on KCP&L's deferred tax balances resulting from the favorable impact of sustained audit positions.

Consolidated KCP&L's income taxes decreased $5.8 million in 2005 compared to 2004. Several factors contributed to the decreased taxes including lower taxable income in 2005. The favorable impact of sustained audit positions on the composite tax rate decreased income taxes $6.3 million, including $3.1 million reflecting a composite tax rate change on deferred tax balances. The domestic manufacturers' deduction provided for under the American Jobs Creation Act of 2004 contributed $1.5 million to the decrease in taxes. When compared to 2004, these 2005 decreases to income taxes were partially offset due to the 2004 release of $10.1 million in tax reserves for the interest component of the IRS 1995-1999 audit settlement, as discussed under consolidated KCP&L interest charges, which resulted in no impact to 2004 net income.

STRATEGIC ENERGY RESULTS OF OPERATIONS

The following table summarizes Strategic Energy's comparative results of operations.

	2006	2005	2004
		(millions)	
Operating revenues	$ 1,534.9	$ 1,474.0	$ 1,372.4
Purchased power	(1,490.3)	(1,368.4)	(1,247.5)
Other operating expenses	(61.5)	(53.4)	(51.3)
Depreciation and amortization	(7.8)	(6.4)	(4.8)
Gain on property	-	(0.1)	-
Operating income (loss)	(24.7)	45.7	68.8
Non-operating income (expenses)	4.2	2.5	1.7
Interest charges	(2.1)	(3.4)	(0.7)
Income taxes	12.7	(16.6)	(24.3)
Minority interest in subsidiaries	-	-	(3.0)
Net income (loss)	$ (9.9)	$ 28.2	$ 42.5

Strategic Energy's 2006 net loss was primarily the result of the after tax impact of $33.4 million in changes in fair value related to non-hedging energy contracts and from cash flow hedge ineffectiveness. Retail MWhs delivered decreased 15% to 16.6 million in 2006 compared to 2005 due to the effect of market conditions in midwestern states and competition in other markets where Strategic Energy serves customers. The impact to net income was partially offset by average retail gross margin per MWh without fair value impacts that increased to $5.93 in 2006 compared to $5.07 in 2005. Additionally, Strategic Energy's other operating expenses increased primarily due to increased incentive compensation and bad debt expense.

Retail MWhs delivered decreased 4% to 19.5 million in 2005 compared to 2004. The average retail gross margin per MWh declined 14% to $5.19 in 2005. The decline in average retail gross margin per MWh in 2005 compared to 2004 was primarily due to an environment of higher and less volatile energy prices, flat to higher forward electricity prices and $8.3 million in 2005 SECA charges in excess of recoveries. The negative impacts on average retail gross margin per MWh were partially offset by $6.8 million for two significant opportunities to manage retail portfolio load requirements, a $2.5 million favorable reduction of a gross receipts tax contingency and an $0.8 million change in fair value related to non-hedging energy contracts and from cash flow hedge ineffectiveness.

	2006	2005	2004
Average retail gross margin per MWh	$ 2.52	$ 5.19	$ 6.01
Change in fair value related to non-hedging energy contracts and from cash flow hedge ineffectiveness	(3.41)	0.12	0.08
Average retail gross margin per MWh without fair value impacts	$ 5.93	$ 5.07	$ 5.93

Average retail gross margin per MWh without fair value impacts is a non-GAAP financial measure that differs from GAAP because it excludes the impact of unrealized fair value gains or losses. Management and the Board of Directors use this as a measurement of Strategic Energy's realized retail gross margin per delivered MWh, which are settled upon delivery at contracted prices. Fair value impacts result from changes in fair value of non-hedging energy contracts and from hedge ineffectiveness associated with MWhs under contract but not yet delivered. Due to their non-cash nature and volatility during periods prior to delivery, management believes excluding these fair value impacts results in a measure of retail gross margin per MWh that is more representative of contracted prices.

As detailed in the table above, average retail gross margin per MWh without the impact of unrealized fair value gains and losses increased to $5.93 in 2006 compared to $5.07 in 2005. The increase was primarily due to the net impact of SECA recoveries and charges as compared to 2005. The net SECA impact increased average retail gross margin per MWh by $0.06 in 2006 and decreased average retail gross margin per MWh by $0.42 in 2005. Additional impacts to the average retail gross margin per MWh included increases primarily due to the management of retail portfolio load requirements, favorable product mix and settlements of supplier contracts. The increases were partially offset by higher customer acquisition costs in 2006.

Strategic Energy Purchased Power

Purchased power is the cost component of Strategic Energy's average retail gross margin. Strategic Energy purchases electricity from power suppliers based on forecasted peak demand for its retail customers. Actual customer demand does not always equate to the volume purchased based on forecasted peak demand. Consequently, Strategic Energy makes short-term power purchases in the wholesale market when necessary to meet actual customer requirements. Strategic Energy also sells any excess retail electricity supply over actual customer requirements back into the wholesale market. These sales occur on many contracts, are usually short-term power sales (day ahead) and typically settle within the reporting period. Excess retail electricity supply sales also include long-term and short-term forward physical sales to wholesale counterparties, which are accounted for on a mark-to-market basis. Strategic Energy typically executes these transactions to manage basis and credit risks. The proceeds from excess retail supply sales are recorded as a reduction of purchased power, as they do not represent the quantity of electricity consumed by Strategic Energy's customers. The amount of excess retail supply sales that reduced purchased power was $80.0 million, $158.5 million and $173.3 million in 2006, 2005 and 2004, respectively. Additionally, in certain markets, Strategic Energy is required to sell to and purchase power from a RTO/ISO rather than directly transact with suppliers and end use customers. The sale and purchase activity related to these certain RTO/ISO markets is reflected on a net basis in Strategic Energy's purchased power.

Strategic Energy utilizes derivative instruments, including forward physical delivery contracts, in the procurement of electricity. Purchased power is also impacted by the net change in fair value related to non-hedging energy contracts and from cash flow hedge ineffectiveness. Net changes in fair value increased purchased power expenses by $56.7 million in 2006 and reduced expenses by $2.5 million in 2005 and $1.7 million in 2004. The change is a result of decreases in the forward market prices for power combined with Strategic Energy designating more derivative instruments as cash flow hedges

that no longer qualify for the NPNS election. See Note 22 to the consolidated financial statements for more information.

Strategic Energy Other Operating Expenses
Strategic Energy's other operating expenses increased $8.1 million in 2006 compared to 2005 primarily due to a $4.5 million increase for incentive compensation and a $4.3 million increase in bad debt expense due to the charge off of smaller customers, which have a higher default rate than Strategic Energy's larger customers. Since 2005, Strategic Energy has significantly expanded its small customer business with approximately 25% of new sales in 2006 to small customers. Strategic Energy's other operating expenses increased $2.1 million in 2005 compared to 2004 primarily due to increased employee related expenses including increased severance and incentive compensation, partially offset by an 11% decrease in full time employees to 240 in 2005.

Strategic Energy Income Taxes
Strategic Energy had a tax benefit of $12.7 million in 2006 compared to tax expense of $16.6 million in 2005 due to a pre-tax loss in 2006 compared to pre-tax income in 2005. The change was driven by a $23.3 million deferred tax benefit in 2006 related to the net changes in fair value related to non-hedging energy contracts and from cash flow hedge ineffectiveness. Strategic Energy's income taxes decreased $7.7 million in 2005 compared to 2004 reflecting lower taxable income partially offset by a net $3.2 million decrease in the allocation of tax benefits from holding company losses pursuant to the Company's inter-company tax allocation agreement.

OTHER NON-REGULATED ACTIVITIES

Investment in Affordable Housing Limited Partnerships - KLT Investments
KLT Investments Inc.'s (KLT Investments) net income in 2006 totaled $4.3 million (including an after-tax reduction of $0.8 million in its affordable housing investment) compared to net income of $5.7 million in 2005 (including an after tax reduction of $6.2 million in its affordable housing investment) and net income of $11.2 million in 2004 (including an after tax reduction of $4.6 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 $1.2 million, $10.0 million and $7.5 million in 2006, 2005 and 2004. Pre-tax reductions in affordable housing investments are estimated to be $2 million for 2007. 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. Even after these estimated reductions, net income from the investments in affordable housing is expected to be positive for 2007 and 2008. The properties underlying the partnership investment are subject to certain risks inherent in real estate ownership and management.

KLT Investments accrued tax credits related to its investments in affordable housing limited partnerships of $9.1 million, $15.4 million and $18.3 million in 2006, 2005 and 2004, respectively. Management estimates tax credits will be $5 million and $2 million for 2007 and 2008, respectively.

KLT Gas Discontinued Operations
Discontinued operations decreased net income $9.2 million in 2005 compared to 2004 primarily due to a gain on the 2004 sale of the KLT Gas portfolio, partially offset by losses from the wind down operations and for an arbitration settlement in 2005. KLT Gas had no active operations in 2006.

GREAT PLAINS ENERGY AND CONSOLIDATED KCP&L SIGNIFICANT BALANCE SHEET CHANGES (December 31, 2006 compared to December 31, 2005)

- Great Plains Energy's and consolidated KCP&L's receivables increased $80.4 million and $44.0 million, respectively. KCP&L's receivables increased $39.7 million due to additional receivables from joint owners of comprehensive energy plan projects. Strategic Energy's receivables increased $38.9 million primarily due to more customers billed on higher index-based rates.
- Great Plains Energy's and consolidated KCP&L's fuel inventories increased $10.7 million primarily due to a $7.0 million increase in coal inventory resulting from an increase in the average days coal burn in inventory as a result of planned plant outages and improved railroad performance in delivering coal. Additionally, coal and coal transportation costs increased fuel inventories.
- Great Plains Energy's combined refundable income taxes and accrued taxes of a net current liability of $14.3 million at December 31, 2006, decreased $22.9 million from December 31, 2005. This decrease was primarily due to Strategic Energy's $7.9 million payment of accrued gross receipts taxes and a decrease at consolidated KCP&L. Consolidated KCP&L's combined refundable income taxes and accrued taxes of a net current liability of $10.9 million at December 31, 2006, decreased $16.5 million from December 31, 2005, primarily due to a $7.8 million receivable for estimated income taxes paid and $5.3 million of 2005 income tax true ups.
- Great Plains Energy's combined deferred income taxes – current assets and deferred income taxes – current liabilities changed from a liability of $7.8 million at December 31, 2005, to an asset of $39.6 million. The temporary differences due to the change in the fair value of Strategic Energy's energy-related derivative instruments increased the asset $42.9 million.
- Great Plains Energy's derivative instruments, including current and deferred assets and liabilities, decreased $188.0 million from a net asset in 2005, to a net liability in 2006, primarily due to a $188.1 million decrease in the fair value of Strategic Energy's energy-related derivative instruments as a result of decreases in the forward market prices for power combined with Strategic Energy designating more derivative instruments as cash flow hedges in 2006 than in 2005.
- Great Plains Energy's and consolidated KCP&L's combined electric utility plant and construction work in progress increased $422.5 million primarily due to $298.7 million related to KCP&L's comprehensive energy plan, including $163.6 million for wind generation, $56.8 million for environmental upgrades and $78.3 million related to Iatan No. 2
- Great Plains Energy's and consolidated KCP&L's regulatory assets increased $254.5 million primarily due to new regulatory assets of $190.0 million for the adoption of SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans" and $21.9 million for pension settlement charges pursuant to orders received from the MPSC and KCC. Additionally, new regulatory assets of $11.9 million were established under the 2006 MPSC and KCC rate orders. See Notes 6 and 8 to the consolidated financial statements for additional information.
- Great Plains Energy's and consolidated KCP&L's prepaid pension costs were reduced to zero upon the adoption of SFAS No. 158.
- Great Plains Energy's other – deferred charges and other assets decreased $22.4 million primarily due to IEC's intangible asset amortization of $10.5 million and a decrease at consolidated KCP&L. Consolidated KCP&L's other – deferred charges and other assets decreased $14.3 million primarily due to the reduction to zero of an intangible pension asset upon adoption of SFAS No. 158.

- Great Plains Energy's and consolidated KCP&L's commercial paper increased $124.5 million primarily to support expenditures related to the comprehensive energy plan.
- Great Plains Energy's and consolidated KCP&L's accounts payable increased $91.2 million and $75.8 million, respectively, primarily due to a $66.1 million increase in payables related to the comprehensive energy plan.
- Great Plains Energy's and consolidated KCP&L's asset retirement obligations decreased $54.1 million due to a $65.0 million decrease for the decommissioning of Wolf Creek as a result of the anticipated new operating license. This decrease was partially offset by a $3.1 million addition for the Spearville Wind Energy Facility and $7.8 million for accretion.
- Great Plains Energy's and consolidated KCP&L's pension liability – deferred credits and other liabilities increased $55.8 million and $46.9 million, respectively, due to the adoption of SFAS No. 158.
- Great Plains Energy's and consolidated KCP&L's regulatory liabilities increased $45.0 million due to a $31.0 million increase in KCP&L's regulatory liability related to the asset retirement obligation for decommissioning of Wolf Creek as a result of the anticipated new operating license and amortization of $10.3 million related to the change in Wolf Creek depreciable life for regulatory purposes in accordance with an MPSC order.
- Great Plains Energy's and consolidated KCP&L's other – deferred credits and other liabilities increased $16.3 million and $27.3 million, respectively, primarily due to a $17.6 million impact of adoption of SFAS No. 158. Consolidated KCP&L also increased due to an intercompany payable to Services of $5.7 million related to unrecognized pension expense.
- Great Plains Energy's accumulated other comprehensive loss increased $39.0 million primarily due to a $74.0 million increase due to changes in the fair value of Strategic Energy's energy related derivative instruments partially offset by activity at consolidated KCP&L. Consolidated KCP&L's accumulated other comprehensive loss at December 31, 2005, decreased $36.6 million resulting in accumulated other comprehensive income at December 31, 2006, due to the adoption of SFAS No. 158 and the related deferral of unrecognized pension expense to a regulatory asset.
- Great Plains Energy's long-term debt decreased $533.4 million primarily to reflect FELINE PRIDES^{SM} Senior Notes, consolidated KCP&L's $225.0 million 6.00% Senior Notes and $144.7 million of Environmental Improvement Revenue Refunding (EIRR) bonds as current maturities. Current maturities of long-term debt for the respective companies increased as a result of these classifications.

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 and credit support provided to Strategic Energy. These items as well as additional cash and capital requirements for the companies are discussed below.

Great Plains Energy's liquid resources at December 31, 2006, consisted of $61.8 million of cash and cash equivalents on hand, including $1.8 million at consolidated KCP&L, and $806.4 million of unused bank lines of credit. The unused lines consisted of $234.9 million from KCP&L's revolving credit facility, $75.2 million from Strategic Energy's revolving credit facility and $496.3 million from Great Plains

Energy's revolving credit facility. At February 20, 2007, Great Plains Energy's and consolidated KCP&L's unused bank lines of credit had decreased $55.2 million and $39.2 million, respectively, from the amounts at December 31, 2006, primarily due to support expenditures for comprehensive energy plan projects. See the Debt Agreements section below for more information on these agreements.

KCP&L currently expects to fund its comprehensive energy plan from a combination of internal and external sources including, but not limited to, contributions from rate increases, capital contributions to KCP&L from Great Plains Energy's equity issuances, new short and long-term debt financing and internally generated funds.

KCP&L expects to meet day-to-day cash flow requirements including interest payments, construction requirements (excluding its comprehensive energy plan), dividends to Great Plains Energy and pension benefit plan funding requirements, discussed below, with internally generated funds. KCP&L may 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 cash flow requirements including interest payments, credit support fees and capital expenditures with internally generated funds. Strategic Energy may 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, seasonal working capital requirements, commodity-price volatility and the effects of counterparty non-performance.

In February 2007, Great Plains Energy entered into an agreement to acquire Aquila. See Note 3 to the consolidated financial statements for additional information.

Cash Flows from Operating Activities

Great Plains Energy and consolidated KCP&L generated positive cash flows from operating activities for the periods presented. The changes in cash flows from operating activities for Great Plains Energy and consolidated KCP&L in 2006 compared to 2005 and in 2005 compared to 2004 reflect KCP&L's sales of SO_2 emission allowances during 2005 resulting in proceeds of $61.0 million and KCP&L's $12.0 million cash settlement of Treasury Locks (T-Locks) in 2005. The timing of the Wolf Creek outage affects the deferred refueling outage costs, deferred income taxes and amortization of nuclear fuel. Other changes in working capital detailed in Note 2 to the consolidated financial statements also impacted operating cash flows. The individual components of working capital vary with normal business cycles and operations.

Cash Flows from 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 $148.6 million and $143.8 million, respectively, in 2006 compared to 2005 due to KCP&L's cash utility capital expenditures, including $234.3 million related to KCP&L's comprehensive energy plan, $10.2 million to upgrade a transmission line, $13.8 million to purchase automated meter reading equipment and $23.4 million to purchase rail cars partially offset by 2005 investing activities discussed below. Additionally in

2006, KCP&L received $15.8 million of litigation recoveries related to Hawthorn No. 5, compared to $10.0 million of insurance recoveries received in 2005.

Great Plains Energy's and consolidated KCP&L's utility capital expenditures increased $136.7 million and $141.6 million, respectively, during 2005 compared to 2004. In 2005, KCP&L exercised its early termination option in the Combustion Turbine Synthetic Lease and subsequently paid $154.0 million to purchase the leased property and made contract payments totaling $25.3 million related to wind generation and environmental equipment upgrades. These payments were partially offset by the $28.5 million buyout of KCP&L's operating lease for vehicles and heavy equipment in 2004.

Cash Flows from Financing Activities

The change in Great Plains Energy's cash flows from financing activities in 2006 compared to 2005 reflects Great Plains Energy's proceeds of $144.3 million from the issuance of 5.2 million shares of common stock at $27.50 per share in May 2006. Fees related to this issuance were $5.2 million. Great Plains Energy used the proceeds to make a $134.6 million equity contribution to KCP&L. Additionally, Great Plains Energy and consolidated KCP&L's net cash from financing activities in 2006 increased due to an increase in KCP&L's commercial paper primarily to support expenditures related to the comprehensive energy plan. Consolidated KCP&L's net cash from financing activities also increased due to a $23.7 million decrease in dividends paid to Great Plains Energy.

The changes in Great Plains Energy's and consolidated KCP&L's cash flows from financing activities in 2005 compared to 2004 reflect KCP&L's retirement of $54.5 million of its medium-term notes and its redemption of $154.6 million of 8.3% Junior Subordinated Deferred Interest Bonds from KCPL Financing I during 2004. 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. These 2004 financing activities at consolidated KCP&L were offset by $225.0 million in equity contributions from Great Plains Energy. Great Plains Energy's 2004 financing activities reflect proceeds of $150.0 million from the June 2004 issuance of 5.0 million shares of common stock at $30 per share and proceeds of $163.6 million from the issuance of 6.5 million FELINE PRIDES. Great Plains Energy used the proceeds to repay short-term borrowings and to fund the equity contributions to KCP&L. Fees related to these issuances were $10.2 million.

In 2005, KCP&L issued $250.0 million of 6.05% unsecured senior notes, $35.9 million of secured EIRR bonds Series 2005 and $50.0 million of unsecured EIRR bonds Series 2005. The proceeds from these issuances were used to repay $250.0 million of 7.125% unsecured senior notes, $35.9 million of secured 1994 Series EIRR bonds and $50.0 million of Series C EIRR bonds.

Significant Financing Activities

Great Plains Energy filed a shelf registration statement with the SEC in 2006 relating to Senior Debt Securities, Subordinated Debt Securities, shares of Common Stock, Warrants, Stock Purchase Contracts and Stock Purchase Units. In 2006, Great Plains Energy issued 5.2 million shares of common stock at $27.50 per share under the shelf registration statement with $144.3 million in gross proceeds and issuance costs of $5.2 million.

In 2006, Great Plains Energy also entered into a forward sale agreement with Merrill Lynch Financial Markets, Inc. (forward purchaser) for 1.8 million shares of Great Plains Energy common stock. The forward purchaser borrowed and sold the same number of shares of Great Plains Energy's common stock to hedge its obligations under the forward sale agreement. Great Plains Energy did not initially receive any proceeds from the sale of common stock shares by the forward purchaser. The forward sale agreement provides for a settlement date or dates to be specified at Great Plains Energy's discretion, subject to certain exceptions, no later than May 23, 2007. Subject to the provisions of the forward sale agreement, Great Plains Energy will receive an amount equal to $26.6062 per share, plus

interest based on the federal funds rate less a spread and less certain scheduled decreases if Great Plains Energy elects to physically settle the forward sale agreement solely by delivering shares of common stock. In most circumstances, Great Plains Energy also has the right, in lieu of physical settlement, to elect cash or net physical settlement. Great Plains Energy currently expects to net cash settle the forward sale agreement.

In 2006, Great Plains Energy entered into a T-Lock with a notional principal amount of $77.6 million to hedge against interest rate fluctuations on future issuances of long-term debt. See Note 22 to the consolidated financial statements for more information.

In February 2007, Great Plains Energy exercised its rights to redeem its $163.6 million FELINE PRIDES senior notes in full satisfaction of each holder's obligation to purchase the Company's common stock under the purchase contracts and issued 5.2 million shares of common stock to the holders of the FELINE PRIDES purchase contracts.

Under stipulations with the MPSC and KCC, Great Plains Energy and KCP&L maintain common equity at not less than 30% and 35%, respectively, of total capitalization. KCP&L's long-term financing activities are subject to the authorization of the MPSC. In 2005, the MPSC authorized KCP&L to issue up to $635.0 million of long-term debt and to enter into interest rate hedging instruments in connection with such debt through December 31, 2009. KCP&L utilized $250.0 million of this amount with the issuance of its 6.05% unsecured senior notes maturing in 2035 leaving $385.0 million of authorization remaining.

During 2006, FERC authorized KCP&L to issue up to a total of $600.0 million in outstanding short-term debt instruments through February 2008. The authorizations are subject to four restrictions: (i) proceeds of debt backed by utility assets must be used for utility purposes; (ii) if any utility assets that secure authorized debt are divested or spun off, the debt must follow the assets and also be divested or spun off; (iii) if any proceeds of the authorized debt are used for non-utility purposes, the debt must follow the non-utility assets (specifically, if the non-utility assets are divested or spun off, then a proportionate share of the debt must follow the divested or spun off non-utility assets); and (iv) if utility assets financed by the authorized short-term debt are divested or spun off to another entity, a proportionate share of the debt must also be divested or spun off.

In January 2007, KCP&L received authorization from FERC, as part of its $600.0 million short-term debt FERC authorization, to issue an aggregate of $150 million of short-term debt in connection with participation in the Great Plains Energy money pool for a period of three years. There will be three participants in the Great Plains Energy money pool: KCP&L, Great Plains Energy and Strategic Energy. The money pool is an internal financing arrangement in which up to $150 million of funds deposited into the money pool by Great Plains Energy and Strategic Energy may be lent on a short-term basis to KCP&L.

During 2006, KCP&L entered into two Forward Starting Swaps (FSS) with a combined notional principal amount of $225.0 million to effectively remove most of the interest rate and credit spread uncertainty with respect to the anticipated refinancing of KCP&L's $225.0 million senior notes that mature in March 2007. See Note 22 to the consolidated financial statements for more information.

In 2006, KCP&L completed an exchange of $250.0 million privately placed notes for $250.0 million registered 6.05% unsecured senior notes maturing in 2035 to fulfill its obligations under a 2005 registration rights agreement.

Debt Agreements

During 2006, Great Plains Energy entered into a five-year $600 million revolving credit facility with a group of banks. The facility replaced a $550 million revolving credit facility with a group of banks. A default by Great Plains Energy or any of its significant subsidiaries on other indebtedness totaling more than $25.0 million is a default under the 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, 2006, the Company was in compliance with this covenant. At December 31, 2006, Great Plains Energy had no cash borrowings and had issued letters of credit totaling $103.7 million under the credit facility as credit support for Strategic Energy.

During 2006, KCP&L entered into a five-year $400 million revolving credit facility with a group of banks to provide support for its issuance of commercial paper and other general corporate purposes. Great Plains Energy and KCP&L may transfer and re-transfer up to $200 million of unused lender commitments between Great Plains Energy's and KCP&L's facilities, so long as the aggregate lender commitments under either facility does not exceed $600 million and the aggregate lender commitments under both facilities does not exceed $1 billion. The facility replaced a $250 million revolving credit facility with a group of banks. A default by KCP&L on other indebtedness totaling more than $25.0 million is a default under the 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, 2006, KCP&L was in compliance with this covenant. At December 31, 2006, KCP&L had $156.4 million of commercial paper outstanding, at a weighted-average interest rate of 5.38%, issued $8.7 million of letters of credit and had no cash borrowings under the facility.

Strategic Energy has a $135 million revolving credit facility with a group of banks that expires in June 2009. As long as Strategic Energy is in compliance with the agreement, it may increase this amount by up to $15 million by increasing the commitment of one or more lenders that have agreed to such increase, or by adding one or more lenders with the consent of the administrative agent. In October 2006, Great Plains Energy, as permitted by the terms of the agreement, requested and received a reduction in its guarantee of this facility from $25 million to $12.5 million. Under this facility, Strategic Energy's maximum it may loan to Great Plains Energy is $20 million. The facility contains a Material Adverse Change (MAC) clause that requires Strategic Energy to represent, prior to receiving funding, that no MAC has occurred. A default by Strategic Energy on 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 $75.0 million, 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 addition, under the terms of this agreement, Strategic Energy is required to maintain a maximum funded indebtedness to EBITDA ratio, as defined in the agreement, of 3.00 to 1.00, on a quarterly basis through June 30, 2007, and 2.75 to 1.00 thereafter. 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, 2006, Strategic Energy was in compliance with these covenants. At December 31, 2006, $59.8 million in letters of credit had been issued and there were no cash borrowings under the agreement.

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, 2006, KLT Investments had $0.9 million in outstanding notes, including current maturities.

Projected Utility Capital Expenditures

KCP&L's utility capital expenditures, excluding allowance for funds used to finance construction, were $475.9 million, $332.1 million and $190.5 million in 2006, 2005 and 2004, respectively. Utility capital expenditures projected for the next three years, excluding allowance for funds used during construction, are detailed in the following table.

	2007	2008	2009
Generating facilities		(millions)	
Iatan No. 2 [(a)]	$ 200.5	$ 352.5	$ 239.0
Wind generation [(a)]	2.9	-	-
Environmental [(a)]	102.1	163.3	64.0
Other	64.9	73.6	82.6
Total generating facilities	370.4	589.4	385.6
Distribution and transmission facilities			
Iatan No. 2 [(a)]	0.3	6.1	5.5
Customer programs & asset management [(a)]	11.3	14.4	15.2
Other	111.6	99.6	100.7
Total distribution and transmission facilities	123.2	120.1	121.4
Nuclear fuel	24.3	17.1	17.9
General facilities	22.6	15.4	19.2
Total	$ 540.5	$ 742.0	$ 544.1

[(a)] Comprehensive energy plan

This utility capital expenditure plan is subject to continual review and change and includes utility capital expenditures related to KCP&L's comprehensive energy plan for environmental investments and new capacity. See Note 6 to the consolidated financial statements for the total comprehensive energy plan estimated capital expenditures by project. If the proposed acquisition of Aquila is completed, Great Plains Energy expects to increase its utility capital expenditures. See Note 3 to the consolidated financial statements 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. All plans meet the funding requirements of the Employee Retirement Income Security Act of 1974 (ERISA) with additional contributions made when deemed financially advantageous.

The Company contributed $19.8 million to the plans in 2006, all paid by KCP&L. The contributions included $14.0 million of funding above the minimum ERISA funding requirements. In 2005, the Company contributed $14.5 million to the plans, which included $10.0 million of funding above the minimum ERISA funding requirements. KCP&L paid $13.8 million of the 2005 contributions.

The Company expects to contribute $33.6 million to the plans in 2007 to meet ERISA funding requirements, all of which will be paid by KCP&L. Management believes KCP&L has adequate access to capital resources through cash flows from operations or through existing lines of credit to support the funding requirements.

The Pension Protection Act of 2006, signed into law on August 17, 2006, alters the manner in which pension plan assets and liabilities are valued for purposes of calculating required pension contributions and changes the timing in which required contributions to underfunded plans are made. The funding rules, which become effective in 2008, could affect the Company's future funding requirements.

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 8 to the consolidated financial statements for additional information.

Credit Ratings

At December 31, 2006, 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	Stable	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.

On February 7, 2007, Standard & Poor's Rating Services placed Great Plains Energy and KCP&L on credit watch with negative implications after the announcement that Great Plains Energy entered into an agreement to acquire Aquila, Inc. At the same time, Standard & Poor's Rating Services also lowered KCP&L's commercial paper credit rating to A-3 from A-2. See Note 3 to the consolidated financial statements for additional information. Also, on February 7, 2007, Moody's Investors Service affirmed the ratings and outlook of Great Plains Energy and KCP&L.

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, its Series 1993A and 1993B EIRR bonds totaling $79.5 million and its secured and unsecured EIRR Bonds Series 2005 totaling $35.9 million and $50.0 million, respectively, 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.

Strategic Energy Supplier Concentration and Credit

Strategic Energy enters into forward physical contracts with multiple suppliers. At December 31, 2006, Strategic Energy's five largest suppliers under forward supply contracts represented 72% of the total future dollar committed purchases. Strategic Energy's five largest suppliers, or their guarantors, are rated investment grade. 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 may be 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. There is no assurance that the supplier in such an instance would make the default payment and/or pay liquidated damages. Strategic Energy's results of operations and financial position could also be affected, in a given period, if it were required to make a payment upon termination of a supplier contract to the extent the contracted price with the supplier exceeded the market value of the contract at the time of termination.

The following tables provide information on Strategic Energy's credit exposure to suppliers, net of collateral, at December 31, 2006.

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	$ 2.8	$ -	$ 2.8	2	$ 2.4
Non-Investment Grade	7.6	6.1	1.5	1	1.5
Internal rating					
Investment Grade	0.1	-	0.1	-	-
Non-Investment Grade	2.5	-	2.5	1	2.5
Total	$ 13.0	$ 6.1	$ 6.9	4	$ 6.4

Maturity Of Credit Risk Exposure Before Credit Collateral			
Rating	Less Than 2 Years	2 - 5 Years	Total Exposure
External rating		(millions)	
Investment Grade	$ 2.8	$ -	$ 2.8
Non-Investment Grade	2.5	5.1	7.6
Internal rating			
Investment Grade	0.1	-	0.1
Non-Investment Grade	1.3	1.2	2.5
Total	$ 6.7	$ 6.3	$ 13.0

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 Investors Service. 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, 2006, Strategic Energy had exposure before collateral to non-investment grade counterparties totaling $10.1 million. In addition, Strategic Energy held collateral totaling $6.1 million limiting its exposure to these non-investment grade counterparties to $4.0 million.

Strategic Energy contracts with national and regional counterparties that have direct supplies and assets in the region of demand. Strategic Energy also manages its counterparty portfolio through disciplined margining, collateral requirements and contract-based netting of credit exposures against payable balances.

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	2007	2008	2009	2010	2011	After 2011	Total
Long-term debt				(millions)			
Principal	$ 389.6	$ 0.3	$ -	$ -	$150.0	$ 605.3	$ 1,145.2
Interest	47.0	42.6	42.5	42.5	41.3	520.8	736.7
Lease obligations	16.7	16.4	11.9	9.0	8.1	82.3	144.4
Pension plans	33.6	-	-	-	-	-	33.6
Purchase obligations							
Fuel	130.9	121.4	65.7	65.7	11.4	185.3	580.4
Purchased capacity	6.8	7.8	8.2	5.4	4.3	14.3	46.8
Purchased power	741.8	330.5	223.2	165.2	82.1	13.3	1,556.1
Comprehensive energy plan	498.8	361.0	130.1	15.2	-	-	1,005.1
Other	34.3	20.9	4.1	9.9	3.3	-	72.5
Total contractual obligations	$ 1,899.5	$ 900.9	$ 485.7	$ 312.9	$300.5	$ 1,421.3	$ 5,320.8

Consolidated KCP&L Contractual Obligations

Payment due by period	2007	2008	2009	2010	2011	After 2011	Total
Long-term debt				(millions)			
Principal	$ 225.5	$ -	$ -	$ -	$150.0	$ 605.3	$ 980.8
Interest	45.3	42.5	42.5	42.5	41.3	520.8	734.9
Lease obligations	15.5	15.4	11.7	9.0	8.1	82.3	142.0
Pension plans	33.6	-	-	-	-	-	33.6
Purchase obligations							
Fuel	130.9	121.4	65.7	65.7	11.4	185.3	580.4
Purchased capacity	6.8	7.8	8.2	5.4	4.3	14.3	46.8
Comprehensive energy plan	498.8	361.0	130.1	15.2	-	-	1,005.1
Other	34.3	20.9	4.1	9.9	3.3	-	72.5
Total contractual obligations	$ 990.7	$ 569.0	$ 262.3	$ 147.7	$218.4	$ 1,408.0	$ 3,596.1

Long-term debt includes current maturities. Long-term debt principal excludes $1.6 million of discounts on senior notes and a $1.8 million liability for the fair value adjustment to the EIRR bonds related to

interest rate swaps. Variable rate interest obligations are based on rates as of December 31, 2006. 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 2007 through 2011 and total $3.7 million after 2011. Lease obligations also include railcars to serve jointly-owned generating units where KCP&L is the managing partner. KCP&L will be reimbursed by the other owners for approximately $2.0 million per year ($21.4 million total) of the amounts included in the table above.

The Company expects to contribute $33.6 million to the pension plans in 2007 to meet ERISA funding requirements, all of which will be paid by KCP&L. Additional contributions to the plans are expected beyond 2007 in amounts sufficient to meet ERISA funding requirements; however, these amounts have not yet been determined.

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. KCP&L has capacity sales agreements not included above that total $11.2 million per year for 2007 through 2010, $6.9 million in 2011 and $3.8 million after 2011.

Purchased power represents Strategic Energy's agreements to purchase electricity at various fixed prices to meet estimated supply requirements. Strategic Energy has firm energy sales contracts not included above for 2007 totaling $172.4 million.

Comprehensive energy plan represents KCP&L's contractual commitments for projects included in its comprehensive energy plan. KCP&L expects to be reimbursed by other owners for their respective share of Iatan No. 2 and environmental retrofit costs included in the comprehensive energy plan contractual commitments. Other purchase obligations represent individual commitments entered into in the ordinary course of business.

Strategic Energy has entered into financial swaps in certain markets to limit the unfavorable effect that future price increases will have on future electricity purchases. These financial swaps settle during the same period as power flows to the retail customer and could result in a cash obligation or a cash receipt. Due to the uncertainty of the future cash flows, these financial swaps have been omitted from the table above.

Great Plains Energy and consolidated KCP&L have long-term liabilities recorded on their consolidated balance sheets at December 31, 2006, 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.

The information in the following table is provided to summarize these agreements.

Other Commercial Commitments Outstanding

	Amount of commitment expiration per period						
	2007	2008	2009	2010	2011	After 2011	Total
				(millions)			
Great Plains Energy Guarantees	$247.2	$ 1.0	$13.4	$ -	$ -	$ -	$261.6
Consolidated KCP&L Guarantees	1.0	1.0	0.9	-	-	-	2.9

KCP&L is contingently liable for guaranteed energy savings under an agreement with a customer, guaranteeing an aggregate value of approximately $2.9 million over the next three years. A subcontractor would indemnify KCP&L for any payments made by KCP&L under this guarantee. Great Plains Energy has provided $258.7 million of guarantees to support certain Strategic Energy power purchases and regulatory requirements. At December 31, 2006, guarantees related to Strategic Energy are as follows:

- Great Plains Energy direct guarantees to counterparties totaling $142.0 million, which expire in 2007,
- Great Plains Energy indemnifications to surety bond issuers totaling $0.5 million, which expire in 2007,
- Great Plains Energy guarantee of Strategic Energy's revolving credit facility totaling $12.5 million, which expires in 2009 and
- Great Plains Energy letters of credit totaling $103.7 million, which expire in 2007.

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, its Series 1993A and 1993B EIRR bonds totaling $79.5 million and EIRR Bond Series 2005 totaling $85.9 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.

New Accounting Standards

See Note 24 to the consolidated financial statements for information regarding new accounting standards.

ITEM 7A. 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 1A. Risk Factors and Item. 7 MD&A 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 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. Though management believes its risk management practices to be effective, it is not possible to identify and eliminate all risk. The companies could experience losses, which could have a material adverse effect on its results of operations or financial position, due to many factors, including unexpectedly large or

rapid movements or disruptions in the energy markets, from regulatory-driven market rule changes and/or bankruptcy or non-performance of customers or counterparties.

Derivative instruments are frequently utilized to execute risk management and hedging strategies. Derivative instruments, such as futures, forward contracts, swaps or options, 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 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 and consolidated KCP&L manage interest expense and short and long-term liquidity through a combination of fixed 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 also be used to achieve the desired combination. Using outstanding balances and annualized interest rates as of December 31, 2006, a hypothetical 10% increase in the interest rates associated with long-term variable rate debt would result in an increase of $1.2 million in interest expense for 2007. Additionally, interest rates impact the fair value of long-term debt. KCP&L had $156.4 million of commercial paper outstanding at December 31, 2006. The principal amount, which will vary during the year, of the commercial paper will drive KCP&L's commercial paper interest expense. Assuming that $156.4 million of commercial paper was outstanding for all of 2007, a hypothetical 10% increase in commercial paper rates would result in an increase of $0.9 million in interest expense for 2007. 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 1% below fair values at December 31, 2006.

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 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 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% increase in the market price of power could result in a $4.0 million decrease in operating income for 2007 related to purchased power. In 2007, approximately 74% of KCP&L's net MWhs generated are expected to be coal-fired. KCP&L currently has all of its coal requirements for 2007 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 2007. 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 $1.1 million in fuel expense for 2007. At December 31, 2006, KCP&L had hedged approximately 30% and 9% of its 2007 and 2008, respectively, projected natural gas usage for generation requirements to serve retail load and firm MWh sales. KCP&L did not have any of its 2006 projected natural gas usage for generation requirements to serve retail load and firm MWh sales hedged at December 31, 2005.

Strategic Energy maintains a commodity-price risk management strategy that uses derivative instruments including forward physical energy purchases, 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. Financial derivative instruments, including 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 market price of purchased power could result in a $2.2 million increase in purchased power expense for 2007.

Strategic Energy has historically utilized certain derivative instruments to protect against significant price volatility for purchased power that have qualified for the NPNS exception, in accordance with SFAS No. 133, as amended. However, as certain markets continue to develop, some derivative instruments may no longer qualify for the NPNS exception. As such, Strategic Energy is designating these derivative instruments as cash flow hedges, where appropriate, which could result in future increased volatility in derivative assets and liabilities, OCI and net income above levels historically experienced. Derivative instruments that were designated as NPNS are accounted for by accrual accounting, which requires the effects of the derivative to be recorded when the derivative contract settles. Accordingly, the increase in derivatives accounted for as cash flow hedges, and the corresponding decrease in derivatives accounted for as NPNS transactions, may affect the timing and nature of accounting recognition, but does not change the underlying economics of the transactions.

Investment Risk

KCP&L maintains trust funds, as required by the NRC, to fund its share of decommissioning the Wolf Creek nuclear power plant. As of December 31, 2006, 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. 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 $5.0 million reduction in the value of the decommissioning trust funds at December 31, 2006. A hypothetical 10% decrease in equity prices would have resulted in a $5.1 million reduction in the fair value of the equity securities at December 31, 2006. KCP&L's exposure to investment 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 would have an insignificant impact on pre-tax net income for 2007.

ITEM 8. CONSOLIDATED FINANCIAL STATEMENTS

GREAT PLAINS ENERGY
Consolidated Statements of Income

Year Ended December 31	2006	As Adjusted 2005	As Adjusted 2004
Operating Revenues	(thousands, except per share amounts)		
Electric revenues - KCP&L	**$ 1,140,357**	$ 1,130,792	$ 1,090,067
Electric revenues - Strategic Energy	**1,532,106**	1,471,490	1,370,760
Other revenues	**2,886**	2,600	3,191
Total	**2,675,349**	2,604,882	2,464,018
Operating Expenses			
Fuel	**229,469**	208,431	176,806
Purchased power - KCP&L	**26,418**	61,263	52,533
Purchased power - Strategic Energy	**1,490,246**	1,368,419	1,247,522
Skill set realignment costs (Note 8)	**9,448**	-	-
Other	**327,917**	327,801	323,663
Maintenance	**83,844**	89,983	84,057
Depreciation and amortization	**160,549**	153,080	150,071
General taxes	**112,601**	109,436	102,756
(Gain) loss on property	**(565)**	3,544	5,133
Total	**2,439,927**	2,321,957	2,142,541
Operating income	**235,422**	282,925	321,477
Non-operating income	**19,885**	19,505	6,799
Non-operating expenses	**(6,702)**	(16,745)	(15,184)
Interest charges	**(71,221)**	(73,787)	(83,030)
Income from continuing operations before income taxes, minority interest in subsidiaries and loss from equity investments	**177,384**	211,898	230,062
Income taxes	**(47,822)**	(39,462)	(55,391)
Minority interest in subsidiaries	**-**	(7,805)	2,131
Loss from equity investments, net of income taxes	**(1,932)**	(434)	(1,531)
Income from continuing operations	**127,630**	164,197	175,271
Discontinued operations, net of income taxes (Note 11)	**-**	(1,899)	7,276
Net income	**127,630**	162,298	182,547
Preferred stock dividend requirements	**1,646**	1,646	1,646
Earnings available for common shareholders	**$ 125,984**	$ 160,652	$ 180,901
Average number of basic common shares outstanding	**78,003**	74,597	72,028
Average number of diluted common shares outstanding	**78,170**	74,743	72,068
Basic earnings (loss) per common share			
Continuing operations	**$ 1.62**	$ 2.18	$ 2.41
Discontinued operations	**-**	(0.03)	0.10
Basic earnings per common share	**$ 1.62**	$ 2.15	$ 2.51
Diluted earnings (loss) per common share			
Continued operations	**$ 1.61**	$ 2.18	$ 2.41
Discontinued operations	**-**	(0.03)	0.10
Diluted earnings per common share	**$ 1.61**	$ 2.15	$ 2.51
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 2006	As Adjusted December 31 2005
ASSETS	(thousands)	
Current Assets		
Cash and cash equivalents	**$ 61,823**	$ 103,068
Restricted cash	**-**	1,900
Receivables, net	**339,399**	259,043
Fuel inventories, at average cost	**27,811**	17,073
Materials and supplies, at average cost	**59,829**	57,017
Deferred refueling outage costs	**13,921**	8,063
Refundable income taxes	**9,832**	-
Deferred income taxes	**39,566**	-
Assets of discontinued operations	**-**	627
Derivative instruments	**6,884**	39,189
Other	**11,717**	13,001
Total	**570,782**	498,981
Nonutility Property and Investments		
Affordable housing limited partnerships	**23,078**	28,214
Nuclear decommissioning trust fund	**104,066**	91,802
Other	**15,663**	17,291
Total	**142,807**	137,307
Utility Plant, at Original Cost		
Electric	**5,268,485**	4,959,539
Less-accumulated depreciation	**2,456,199**	2,322,813
Net utility plant in service	**2,812,286**	2,636,726
Construction work in progress	**214,493**	100,952
Nuclear fuel, net of amortization of $103,381 and $115,240	**39,422**	27,966
Total	**3,066,201**	2,765,644
Deferred Charges and Other Assets		
Regulatory assets	**434,392**	179,922
Prepaid pension costs	**-**	98,295
Goodwill	**88,139**	87,624
Derivative instruments	**3,544**	21,812
Other	**29,795**	52,204
Total	**555,870**	439,857
Total	**$ 4,335,660**	$ 3,841,789

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

GREAT PLAINS ENERGY
Consolidated Balance Sheets

	December 31 2006	As Adjusted December 31 2005
LIABILITIES AND CAPITALIZATION	(thousands)	
Current Liabilities		
Notes payable	$ -	$ 6,000
Commercial paper	**156,400**	31,900
Current maturities of long-term debt	**389,634**	1,675
EIRR bonds classified as current	**144,742**	-
Accounts payable	**322,724**	231,496
Accrued taxes	**24,106**	37,140
Accrued interest	**14,082**	13,329
Accrued payroll and vacations	**33,266**	36,024
Pension and post retirement liability	**1,037**	-
Deferred income taxes	-	7,757
Supplier collateral	-	1,900
Liabilities of discontinued operations	-	64
Derivative instruments	**91,482**	7,411
Other	**25,520**	25,658
Total	**1,202,993**	400,354
Deferred Credits and Other Liabilities		
Deferred income taxes	**622,847**	621,359
Deferred investment tax credits	**28,458**	29,698
Asset retirement obligations	**91,824**	145,907
Pension liability	**143,170**	87,355
Regulatory liabilities	**114,674**	69,641
Derivative instruments	**61,146**	7,750
Other	**82,122**	65,787
Total	**1,144,241**	1,027,497
Capitalization		
Common shareholders' equity		
Common stock-150,000,000 shares authorized without par value		
80,405,035 and 74,783,824 shares issued, stated value	**896,817**	744,457
Retained earnings	**493,399**	498,632
Treasury stock-53,499 and 43,376 shares, at cost	**(1,614)**	(1,304)
Accumulated other comprehensive loss	**(46,686)**	(7,727)
Total	**1,341,916**	1,234,058
Cumulative preferred stock $100 par value		
3.80% - 100,000 shares issued	**10,000**	10,000
4.50% - 100,000 shares issued	**10,000**	10,000
4.20% - 70,000 shares issued	**7,000**	7,000
4.35% - 120,000 shares issued	**12,000**	12,000
Total	**39,000**	39,000
Long-term debt (Note 19)	**607,510**	1,140,880
Total	**1,988,426**	2,413,938
Commitments and Contingencies (Note 13)		
Total	**$ 4,335,660**	$ 3,841,789

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	2006	As Adjusted 2005	As Adjusted 2004
Cash Flows from Operating Activities		(thousands)	
Net income	**$ 127,630**	$ 162,296	$ 182,547
Adjustments to reconcile income to net cash from operating activities:			
Depreciation and amortization	**160,549**	153,080	150,090
Amortization of:			
Nuclear fuel	**14,392**	13,374	14,159
Other	**9,271**	10,580	11,827
Deferred income taxes, net	**(10,983)**	(23,250)	31,259
Investment tax credit amortization	**(1,240)**	(3,889)	(3,984)
Loss from equity investments, net of income taxes	**1,932**	434	1,531
(Gain) loss on property	**(565)**	3,295	(9,686)
Minority interest in subsidiaries	**-**	7,805	(2,131)
Fair value impacts from energy contracts	**56,757**	(2,452)	(1,734)
Other operating activities (Note 2)	**(48,761)**	95,616	(19,808)
Net cash from operating activities	**308,982**	416,891	354,070
Cash Flows from Investing Activities			
Utility capital expenditures	**(475,931)**	(327,283)	(190,548)
Allowance for borrowed funds used during construction	**(5,686)**	(1,598)	(1,498)
Purchases of investments	**-**	(14,976)	(35,003)
Purchases of nonutility property	**(4,205)**	(6,853)	(6,108)
Proceeds from sale of assets and investments	**433**	17,369	67,457
Purchases of nuclear decommissioning trust investments	**(49,667)**	(34,607)	(49,720)
Proceeds from nuclear decommissioning trust investments	**46,005**	31,055	46,167
Purchase of additional indirect interest in Strategic Energy	**(700)**	-	(90,033)
Hawthorn No. 5 partial insurance recovery	**-**	10,000	30,810
Hawthorn No. 5 partial litigation recoveries	**15,829**	-	1,139
Other investing activities	**(1,785)**	(930)	(7,081)
Net cash from investing activities	**(475,707)**	(327,823)	(234,418)
Cash Flows from Financing Activities			
Issuance of common stock	**153,649**	9,061	153,662
Issuance of long-term debt	**-**	334,417	163,600
Issuance fees	**(6,172)**	(4,522)	(14,496)
Repayment of long-term debt	**(1,675)**	(339,152)	(213,943)
Net change in short-term borrowings	**118,500**	17,900	(67,000)
Dividends paid	**(132,653)**	(125,484)	(120,806)
Other financing activities	**(6,169)**	(5,975)	(7,309)
Net cash from financing activities	**125,480**	(113,755)	(106,292)
Net Change in Cash and Cash Equivalents	**(41,245)**	(24,687)	13,360
Less: Net Change in Cash and Cash Equivalents from Discontinued Operations	**-**	(626)	458
Cash and Cash Equivalents at Beginning of Year	**103,068**	127,129	114,227
Cash and Cash Equivalents at End of Year	**$ 61,823**	$ 103,068	$ 127,129

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

GREAT PLAINS ENERGY
Consolidated Statements of Common Shareholders' Equity

Year to Date December 31	2006		As Adjusted 2005		As Adjusted 2004	
	Shares	**Amount**	Shares	Amount	Shares	Amount
Common Stock			(thousands, except share amounts)			
Beginning balance	**74,783,824**	**$ 744,457**	74,394,423	$ 731,977	69,259,203	$ 602,551
Issuance of common stock	**5,574,385**	**153,649**	313,026	9,400	5,121,887	153,662
Issuance of restricted common stock	**46,826**	**1,320**	76,375	2,334	13,333	396
Common stock issuance fees		**(5,198)**		-		(5,434)
Equity compensation expense		**2,592**		1,394		181
Unearned Compensation						
Issuance of restricted common stock		**(1,355)**		(2,434)		(396)
Forfeiture of restricted common stock		**56**		324		-
Compensation expense recognized		**1,265**		1,415		636
FELINE PRIDES[SM] purchase contract adjustment, allocated fees and expenses		**-**		-		(19,603)
Other		**31**		47		(16)
Ending balance	**80,405,035**	**896,817**	74,783,824	744,457	74,394,423	731,977
Retained Earnings						
Beginning balance		**498,632**		462,134		391,750
Net income		**127,630**		162,298		182,547
Loss on reissuance of treasury stock		**-**		-		(193)
Cumulative effect of a change in accounting principle (Note 5)		**-**		-		8,907
Dividends:						
Common stock		**(130,959)**		(123,838)		(119,160)
Preferred stock - at required rates		**(1,646)**		(1,646)		(1,646)
Performance shares		**(258)**		(260)		-
Options		**-**		(56)		(71)
Ending balance		**493,399**		498,632		462,134
Treasury Stock						
Beginning balance	**(43,376)**	**(1,304)**	(28,488)	(856)	(3,265)	(121)
Treasury shares acquired	**(11,338)**	**(346)**	(18,385)	(553)	(54,683)	(1,645)
Treasury shares reissued	**1,215**	**36**	3,497	105	29,460	910
Ending balance	**(53,499)**	**(1,614)**	(43,376)	(1,304)	(28,488)	(856)
Accumulated Other Comprehensive Loss						
Beginning balance		**(7,727)**		(41,018)		(36,886)
Derivative hedging activity, net of tax		**(74,721)**		28,397		931
Minimum pension obligation, net of tax		**15,961**		4,894		(5,063)
Adjustment to initially apply SFAS No. 158, net of tax (Note 8)		**(170,218)**		-		-
Regulatory adjustment		**190,019**		-		-
Ending balance		**(46,686)**		(7,727)		(41,018)
Total Common Shareholders' Equity		**$ 1,341,916**		$ 1,234,058		$ 1,152,237

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	2006	As Adjusted 2005	As Adjusted 2004
		(thousands)	
Net income	**$ 127,630**	$ 162,298	$ 182,547
Other comprehensive income			
Gain (loss) on derivative hedging instruments	**(181,597)**	84,070	2,649
Income taxes	**75,044**	(34,718)	(1,126)
Net gain (loss) on derivative hedging instruments	**(106,553)**	49,352	1,523
Reclassification to expenses, net of tax	**31,832**	(20,955)	(592)
Derivative hedging activity, net of tax	**(74,721)**	28,397	931
Change in minimum pension obligation	**25,579**	8,722	(7,624)
Income taxes	**(9,618)**	(3,828)	2,561
Net change in minimum pension obligation	**15,961**	4,894	(5,063)
Comprehensive income	**$ 68,870**	$ 195,589	$ 178,415

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	2006	As Adjusted 2005	As Adjusted 2004
Operating Revenues		(thousands)	
Electric revenues	**$ 1,140,357**	$ 1,130,792	$ 1,090,067
Other revenues	**-**	113	1,568
Total	**1,140,357**	1,130,905	1,091,635
Operating Expenses			
Fuel	**229,469**	208,431	176,806
Purchased power	**26,418**	61,263	52,533
Skill set realignment costs (Note 8)	**9,347**	-	-
Other	**260,281**	265,759	259,125
Maintenance	**83,833**	89,954	83,989
Depreciation and amortization	**152,714**	146,610	145,246
General taxes	**107,858**	104,823	98,984
(Gain) loss on property	**(572)**	4,613	5,133
Total	**869,348**	881,453	821,816
Operating income	**271,009**	249,452	269,819
Non-operating income	**14,965**	16,104	5,402
Non-operating expenses	**(5,363)**	(4,281)	(7,407)
Interest charges	**(60,988)**	(61,841)	(74,170)
Income before income taxes and minority interest in subsidiaries	**219,623**	199,434	193,644
Income taxes	**(70,302)**	(47,984)	(53,703)
Minority interest in subsidiaries	**-**	(7,805)	5,087
Net income	**$ 149,321**	$ 143,645	$ 145,028

The disclosures regarding consolidated 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 2006	As Adjusted December 31 2005
ASSETS	(thousands)	
Current Assets		
Cash and cash equivalents	**$ 1,788**	$ 2,961
Receivables, net	**114,294**	70,264
Fuel inventories, at average cost	**27,811**	17,073
Materials and supplies, at average cost	**59,829**	57,017
Deferred refueling outage costs	**13,921**	8,063
Refundable income taxes	**7,229**	-
Deferred income taxes	**52**	2,538
Prepaid expenses	**9,673**	11,292
Derivative instruments	**179**	-
Total	**234,776**	169,208
Nonutility Property and Investments		
Nuclear decommissioning trust fund	**104,066**	91,802
Other	**6,480**	7,694
Total	**110,546**	99,496
Utility Plant, at Original Cost		
Electric	**5,268,485**	4,959,539
Less-accumulated depreciation	**2,456,199**	2,322,813
Net utility plant in service	**2,812,286**	2,636,726
Construction work in progress	**214,493**	100,952
Nuclear fuel, net of amortization of $103,381 and $115,240	**39,422**	27,966
Total	**3,066,201**	2,765,644
Deferred Charges and Other Assets		
Regulatory assets	**434,392**	179,922
Prepaid pension costs	**-**	98,002
Other	**13,584**	27,905
Total	**447,976**	305,829
Total	**$ 3,859,499**	$ 3,340,177

The disclosures regarding consolidated 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 2006	As Adjusted December 31 2005
LIABILITIES AND CAPITALIZATION	(thousands)	
Current Liabilities		
Notes payable to Great Plains Energy	$ 550	$ 500
Commercial paper	156,400	31,900
Current maturities of long-term debt	225,500	-
EIRR bonds classified as current	144,742	-
Accounts payable	181,805	106,040
Accrued taxes	18,165	27,448
Accrued interest	12,461	11,549
Accrued payroll and vacations	24,641	27,520
Pension and post retirement liability	841	-
Derivative instruments	2,687	-
Other	8,469	8,600
Total	776,261	213,557
Deferred Credits and Other Liabilities		
Deferred income taxes	660,046	627,048
Deferred investment tax credits	28,458	29,698
Asset retirement obligations	91,824	145,907
Pension liability	132,216	85,301
Regulatory liabilities	114,674	69,641
Derivative instruments	39	2,601
Other	65,651	38,387
Total	1,092,908	998,583
Capitalization		
Common shareholder's equity		
Common stock-1,000 shares authorized without par value		
1 share issued, stated value	1,021,656	887,041
Retained earnings	354,802	294,481
Accumulated other comprehensive income (loss)	6,685	(29,909)
Total	1,383,143	1,151,613
Long-term debt (Note 19)	607,187	976,424
Total	1,990,330	2,128,037
Commitments and Contingencies (Note 13)		
Total	$ 3,859,499	$ 3,340,177

The disclosures regarding consolidated 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	2006	As Adjusted 2005	As Adjusted 2004
Cash Flows from Operating Activities		(thousands)	
Net income	**$ 149,321**	$ 143,645	$ 145,028
Adjustments to reconcile income to net cash from operating activities:			
Depreciation and amortization	**152,714**	146,610	145,246
Amortization of:			
Nuclear fuel	**14,392**	13,374	14,159
Other	**6,617**	7,681	7,719
Deferred income taxes, net	**17,411**	(33,637)	11,801
Investment tax credit amortization	**(1,240)**	(3,889)	(3,984)
(Gain) loss on property	**(572)**	4,613	5,133
Minority interest in subsidiaries	**-**	7,805	(5,087)
Other operating activities (Note 2)	**(39,408)**	79,284	(3,756)
Net cash from operating activities	**299,235**	365,486	316,259
Cash Flows from Investing Activities			
Utility capital expenditures	**(475,931)**	(332,055)	(190,548)
Allowance for borrowed funds used during construction	**(5,686)**	(1,598)	(1,498)
Purchases of nonutility property	**(62)**	(127)	(254)
Proceeds from sale of assets	**433**	469	7,465
Purchases of nuclear decommissioning trust investments	**(49,667)**	(34,607)	(49,720)
Proceeds from nuclear decommissioning trust investments	**46,005**	31,055	46,167
Hawthorn No. 5 partial insurance recovery	**-**	10,000	30,810
Hawthorn No. 5 partial litigation recoveries	**15,829**	-	1,139
Other investing activities	**(983)**	(930)	(7,100)
Net cash from investing activities	**(470,062)**	(327,793)	(163,539)
Cash Flows from Financing Activities			
Issuance of long-term debt	**-**	334,417	-
Repayment of long-term debt	**-**	(335,922)	(209,140)
Net change in short-term borrowings	**124,550**	32,376	(21,959)
Dividends paid to Great Plains Energy	**(89,000)**	(112,700)	(119,160)
Equity contribution from Great Plains Energy	**134,615**	-	225,000
Issuance fees	**(511)**	(4,522)	(2,362)
Net cash from financing activities	**169,654**	(86,351)	(127,621)
Net Change in Cash and Cash Equivalents	**(1,173)**	(48,658)	25,099
Cash and Cash Equivalents at Beginning of Year	**2,961**	51,619	26,520
Cash and Cash Equivalents at End of Year	**$ 1,788**	$ 2,961	$ 51,619

The disclosures regarding consolidated 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 Common Shareholder's Equity

Year to Date December 31	2006		As Adjusted 2005		As Adjusted 2004	
	Shares	**Amount**	Shares	Amount	Shares	Amount
Common Stock			(thousands, except share amounts)			
Beginning balance	**1**	**$ 887,041**	1	$ 887,041	1	$ 662,041
Equity contribution from Great Plains Energy	**-**	**134,615**	-	-	-	225,000
Ending balance	**1**	**1,021,656**	1	887,041	1	887,041
Retained Earnings						
Beginning balance		**294,481**		263,536		228,761
Net income		**149,321**		143,645		145,028
Cumulative effect of a change in accounting principle (Note 5)		**-**		-		8,907
Dividends:						
Common stock held by Great Plains Energy		**(89,000)**		(112,700)		(119,160)
Ending balance		**354,802**		294,481		263,536
Accumulated Other Comprehensive Income (Loss)						
Beginning balance		**(29,909)**		(40,334)		(35,244)
Derivative hedging activity, net of tax		**(741)**		7,571		(233)
Minimum pension obligation, net of tax		**15,913**		2,854		(4,857)
Adjustment to initially apply SFAS No. 158 (Note 8)		**(168,597)**		-		-
Regulatory adjustment		**190,019**		-		-
Ending balance		**6,685**		(29,909)		(40,334)
Total Common Shareholder's Equity		**$ 1,383,143**		$ 1,151,613		$ 1,110,243

The disclosures regarding consolidated 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	2006	As Adjusted 2005	As Adjusted 2004
		(thousands)	
Net income	**$ 149,321**	$ 143,645	$ 145,028
Other comprehensive income			
Gain (loss) on derivative hedging instruments	**(788)**	12,650	280
Income taxes	**296**	(4,759)	(111)
Net gain (loss) on derivative hedging instruments	**(492)**	7,891	169
Reclassification to expenses, net of tax	**(249)**	(320)	(402)
Derivative hedging activity, net of tax	**(741)**	7,571	(233)
Change in minimum pension obligation	**25,502**	5,410	(7,321)
Income taxes	**(9,589)**	(2,556)	2,464
Net change in minimum pension obligation	**15,913**	2,854	(4,857)
Comprehensive income	**$ 164,493**	$ 154,070	$ 139,938

The disclosures regarding consolidated 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 and does not own or operate any significant assets other than the stock of its subsidiaries. Great Plains Energy has four wholly owned direct subsidiaries with operations or active subsidiaries:

- KCP&L is an integrated, regulated electric utility that provides electricity to customers primarily in the states of Missouri and Kansas. KCP&L has two wholly owned subsidiaries, Kansas City Power & Light Receivables Company (Receivables Company) and Home Service Solutions Inc. (HSS). HSS has no active operations.
- KLT Inc. is an intermediate holding company that primarily holds indirect interests in Strategic Energy, L.L.C. (Strategic Energy), which provides competitive retail electricity supply services in several electricity markets offering retail choice, and holds investments in affordable housing limited partnerships. KLT Inc. also wholly owns KLT Gas Inc. (KLT Gas), which has no active operations.
- 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 indirectly owns 100% of Strategic Energy.
- Great Plains Energy Services Incorporated (Services) provides services at cost to Great Plains Energy and its subsidiaries, including consolidated KCP&L.

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 HSS, Services, all KLT Inc. activity other than Strategic Energy, and holding company operations.

Cash and Cash Equivalents

Cash equivalents consist of highly liquid investments with original maturities of three months or less at acquisition. For Great Plains Energy, this includes Strategic Energy's cash held in trust of $8.8 million and $21.9 million at December 31, 2006 and 2005, 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. Strategic Energy held no restricted cash collateral at December 31, 2006, and $1.9 million at December 31, 2005.

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 nuclear decommissioning trust fund assets 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 1% below fair values at December 31, 2006.

Derivative instruments – 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.

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. Derivative instruments designated as normal purchases and normal sales (NPNS) and cash flow hedges are used solely for hedging purposes and are not issued or held for speculative reasons.

The Company considers various qualitative factors, such as contract and market place attributes, in designating derivative instruments at inception. The Company may elect the NPNS exception, which requires the effects of the derivative to be recorded as the underlying contract settles.

The Company accounts for derivative instruments that are not designated as NPNS as cash flow hedges or non-hedging derivatives, which are recorded as assets or liabilities on the consolidated balance sheets at fair value. At the inception of a derivative instrument, the Company designates its derivative instrument as NPNS, a cash flow hedge or a non-hedging derivative under the requirements of SFAS No. 133. In addition, if a derivative instrument is designated as a cash flow hedge, the Company documents its method of determining hedge effectiveness and measuring ineffectiveness. See Note 22 for additional information regarding derivative financial instruments and hedging activities.

Investments in Affordable Housing Limited Partnerships
At December 31, 2006, KLT Investments had $23.1 million of investments in affordable housing limited partnerships. Approximately 67% 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, $15.1 million exceed this 5% level but were made before May 19, 1995. Management does not anticipate making significant 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 $1.2 million, $10.0 million and $7.5 million in 2006, 2005 and 2004, 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.

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 43 years.

Utility Plant
KCP&L's utility plant is stated at historical cost. 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 Deferred 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.

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 7.8% in 2006, 7.1% in 2005 and 8.6% in 2004.

The balances of utility plant, at original cost, with a range of estimated useful lives are listed in the following table.

December 31	2006	2005
Utility Plant, at original cost	(millions)	
Production (23 - 42 years)	$ 3,135.6	$ 2,970.1
Transmission (27 - 76 years)	364.3	331.2
Distribution (8 - 75 years)	1,465.7	1,377.3
General (5 - 50 years)	302.9	280.9
Total [a]	$ 5,268.5	$ 4,959.5

[a] Includes $40.3 million and $80.4 million of land and other assets that are not depreciated.

Depreciation 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 approximately 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 2006, 2005 and 2004 were 11.5%, 11.2% and 11.8%, respectively. Other Great Plains Energy nonutility property annual depreciation rates for 2006, 2005 and 2004 were 23.4%, 20.4% and 24.2%, 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 period, three years, resulting in a higher annual depreciation rate.

As part of an acquisition of an additional interest in Strategic Energy, IEC recorded intangible assets with finite lives. These intangible assets include the fair value of customer relationships and asset information systems that are being amortized over 72 and 44 months, respectively. An intangible asset for the fair value of acquired supply contracts was fully amortized at December 31, 2006.

Deferred Refueling Outage Costs
KCP&L uses the deferral method to account for operations and maintenance expenses incurred in support of the scheduled refueling outages and amortizes them evenly (monthly) over the unit's operating cycle of 18 months until the next scheduled outage. Replacement power costs during an outage are expensed as incurred.

Nuclear Plant Decommissioning Costs
Nuclear plant decommissioning cost estimates are based on the immediate dismantlement method and include the costs of decontamination, dismantlement and site restoration. Based on these cost estimates, KCP&L contributes to a tax-qualified trust fund to be used to decommission Wolf Creek Generating Station (Wolf Creek). Related liabilities for decommissioning are included on KCP&L's balance sheet in Asset Retirement Obligations (AROs). As a result of the authorized regulatory treatment and related regulatory accounting, differences between the decommissioning trust fund asset and the related ARO are recorded as a regulatory asset or liability. See Note 16 for discussion of AROs including those associated with nuclear plant decommissioning costs.

Regulatory Matters
KCP&L, an integrated, regulated electric utility, 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 if KCP&L were not regulated. See Note 6 for additional information concerning regulatory matters.

Revenue Recognition
KCP&L and Strategic Energy recognize revenues on sales of electricity when the service is provided. Revenues recorded include electric services provided but not yet billed by KCP&L and Strategic Energy. Unbilled revenues are recorded for kWh usage in the period following the customers' billing cycle to the end of the month. The estimate is based on net system kWh usage less actual billed kWhs. Estimated unbilled kWhs are allocated and priced by state across the rate classes based on the following month budget.

As a public utility, KCP&L collects from customers gross receipts taxes levied by state and local governments. These taxes are recorded gross in operating revenues and general taxes on Great Plains Energy's and consolidated KCP&L's statements of income. KCP&L's gross receipts taxes collected were $34.1 million, $39.3 million and $37.6 million in 2006, 2005 and 2004, respectively.

Strategic Energy purchases electricity from power suppliers based on forecasted peak demand for its retail customers. Actual customer demand does not always equate to the volume purchased based on forecasted peak demand. Consequently, Strategic Energy sells any excess retail electricity supply over actual customer requirements back into the wholesale market. The proceeds from excess retail supply sales are recorded as a reduction of purchased power, as they do not represent the quantity of electricity consumed by Strategic Energy's customers. The amount of excess retail supply sales that reduced purchased power was $80.0 million, $158.5 million and $173.3 million in 2006, 2005 and 2004, respectively.

KCP&L and Strategic Energy record sale and purchase activity on a net basis in purchased power when RTO/ISO markets require them to sell and purchase power from the RTO/ISO rather than directly transact with suppliers and end-use customers.

KCP&L collects sales taxes from customers and remits to state and local governments. These taxes are presented on a net basis on Great Plains Energy's and consolidated KCP&L's statements of income.

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 uncollectible.

Property Gains and Losses
Net gains and losses from the sales of assets, businesses and asset impairments are recorded in operating expenses.

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.

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, "Goodwill and Other

Intangible Assets." The annual test must be performed at the same time each year. 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 7 for additional information.

Income Taxes
In accordance with SFAS No. 109, "Accounting for Income Taxes," Great Plains Energy has recognized deferred taxes for 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 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 taxable income of each company in the consolidated federal or combined state returns. Consistent with its 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 net 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.

Basic and Diluted Earnings per Common Share Calculation
To determine basic EPS, preferred stock dividend requirements are deducted from income from continuing operations and net income before dividing by the 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. The effect of dilutive securities, calculated using the treasury stock method, assumes the issuance of common shares applicable to stock options, performance shares, restricted stock, a forward sale agreement and FELINE PRIDES^{SM}.

The following table reconciles Great Plains Energy's basic and diluted EPS.

	2006	As Adjusted 2005	As Adjusted 2004
Income	(millions, except per share amounts)		
Income from continuing operations	$ 127.6	$ 164.2	$ 175.2
Less: preferred stock dividend requirements	1.6	1.6	1.6
Income available to common stockholders	$ 126.0	$ 162.6	$ 173.6
Common Shares Outstanding			
Average number of common shares outstanding	78.0	74.6	72.0
Add: effect of dilutive securities	0.2	0.1	0.1
Diluted average number of common shares outstanding	78.2	74.7	72.1
Basic EPS from continuing operations	$ 1.62	$ 2.18	$ 2.41
Diluted EPS from continuing operations	$ 1.61	$ 2.18	$ 2.41

The computation of diluted EPS excludes anti-dilutive shares for 2006 of 96,601 performance shares and 116,469 restricted stock shares. The computation of diluted EPS excludes anti-dilutive shares for 2005 of 20,493 performance shares. Additionally, for 2006, 2005 and 2004, 6.5 million of anti-dilutive FELINE PRIDES were excluded from the computation of diluted EPS and there were no anti-dilutive shares applicable to stock options or a forward sale agreement.

In February 2007, 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 20, 2007, to shareholders of record as of February 27, 2007. The Board of Directors also declared regular dividends on Great Plains Energy's preferred stock, payable June 1, 2007, to shareholders of record as of May 10, 2007.

2. SUPPLEMENTAL CASH FLOW INFORMATION

Great Plains Energy Other Operating Activities

	2006	As Adjusted 2005	As Adjusted 2004
Cash flows affected by changes in:		(millions)	
Receivables	$ (80.8)	$ 6.6	$ (37.5)
Fuel inventories	(10.7)	4.9	1.8
Materials and supplies	(2.8)	(2.6)	2.2
Accounts payable	68.1	12.4	9.6
Accrued taxes	(22.5)	(23.1)	15.3
Accrued interest	0.7	1.6	(1.0)
Deposits with suppliers	-	0.1	0.8
Deferred refueling outage costs	(5.9)	(4.0)	8.7
Pension and postretirement benefit assets and obligations	3.6	8.4	(10.4)
Allowance for equity funds used during construction	(5.0)	(1.8)	(2.1)
Proceeds from the sale of SO_2 emission allowances	0.8	61.0	0.3
Proceeds from T-Locks	-	12.0	-
Other	5.7	20.1	(7.5)
Total other operating activities	$ (48.8)	$ 95.6	$ (19.8)
Cash paid during the period:			
Interest	$ 67.7	$ 68.9	$ 84.1
Income taxes	$ 77.7	$ 84.4	$ 38.6
Non-cash investing activities:			
Liabilities assumed for capital expenditures	$ 38.7	$ 13.4	$ -

Consolidated KCP&L Other Operating Activities

	2006	As Adjusted 2005	As Adjusted 2004
Cash flows affected by changes in:		(millions)	
Receivables	$ (44.7)	$ (8.5)	$ 1.6
Fuel inventories	(10.7)	4.9	1.8
Materials and supplies	(2.8)	(2.6)	2.2
Accounts payable	52.4	16.3	1.8
Accrued taxes	(16.5)	(17.2)	(6.6)
Accrued interest	0.9	1.7	(2.0)
Deferred refueling outage costs	(5.9)	(4.0)	8.7
Pension and postretirement benefit assets and obligations	0.7	4.6	(8.0)
Allowance for equity funds used during construction	(5.0)	(1.8)	(2.1)
Proceeds from the sale of SO_2 emission allowances	0.8	61.0	0.3
Proceeds from T-Locks	-	12.0	-
Other	(8.6)	12.9	(1.5)
Total other operating activities	$ (39.4)	$ 79.3	$ (3.8)
Cash paid during the period:			
Interest	$ 57.9	$ 57.6	$ 73.8
Income taxes	$ 70.9	$ 104.1	$ 64.9
Non-cash investing activities:			
Liabilities assumed for capital expenditures	$ 38.2	$ 12.8	$ -

Significant Non-Cash Items

Asset Retirement Obligations

In 2006, Wolf Creek Nuclear Operating Corporation (WCNOC) submitted an application to the Nuclear Regulatory Commission (NRC) for a new operating license for Wolf Creek, which would extend Wolf Creek's operating period to 2045. Due to the effect of computing the present value of the asset retirement obligation (ARO) at the end of the extended operating period, KCP&L recorded a $65.0 million decrease in the ARO to decommission Wolf Creek with a $25.8 million net decrease in property and equipment. The regulatory asset for ARO decreased $8.2 million and a $31.0 million regulatory liability was established to recognize funding of the related decommissioning trust in excess of the ARO due to the extended operating period. This activity had no impact to Great Plains Energy's or consolidated KCP&L's 2006 cash flows.

During 2005, KCP&L recorded AROs totaling $26.7 million, increased net utility plant by $13.0 million and increased regulatory assets by $13.7 million. This activity had no impact on Great Plains Energy and consolidated KCP&L's 2005 net income and had no effect on 2005 cash flows. See Note 16 for additional information.

Unrecognized Pension Expense

In December 2006, the Company adopted SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Post Retirement Plans." See Note 8 for the effect of applying SFAS No. 158 to the Company's balance sheet at December 31, 2006. The adoption of SFAS No. 158 had no impact on Great Plains Energy's and consolidated KCP&L's 2006 cash flows.

3. ANTICIPATED ACQUISITION OF AQUILA, INC.

On February 7, 2007, Great Plains Energy entered into an agreement to acquire Aquila, Inc. (Aquila). Immediately prior to Great Plains Energy's acquisition of Aquila, Black Hills Corporation will acquire Aquila's electric utility in Colorado and its gas utilities in Colorado, Kansas, Nebraska and Iowa plus associated liabilities for a total of $940 million in cash, subject to closing adjustments. Each of the two transactions is conditioned on the completion of the other transaction and is expected to close in 2008. Following closing, Great Plains Energy will own Aquila and its Missouri-based utilities consisting of the Missouri Public Service and St. Joseph Light & Power divisions as well as Aquila's merchant service operations, which primarily consists of the 340MW Crossroads power generating facility and residential natural gas contracts.

Great Plains Energy will acquire all outstanding shares of Aquila for $1.80 in cash plus 0.0856 of a share of Great Plains Energy common stock for each share of Aquila common stock in a transaction valued at approximately $1.7 billion, or $4.54 per share, based on Great Plains Energy's closing stock price on February 6, 2007. In addition, Great Plains Energy will assume approximately $1 billion of Aquila's debt. The proceeds from the asset sale to Black Hills Corporation will be used to fund the cash portion of the consideration to Aquila shareholders and to reduce existing Aquila debt.

Great Plains Energy's acquisition of Aquila was unanimously approved by both Great Plains Energy's and Aquila's Boards of Directors and is subject to the approval of both Great Plains Energy and Aquila shareholders; regulatory approvals from the Public Service Commission of the State of Missouri (MPSC), The State Corporation Commission of the State of Kansas (KCC), and FERC; Hart-Scott-Rodino antitrust review; as well as other customary conditions.

The transaction will add about 300,000 electric utility customers and approximately 1,800 MW of generating capacity. Aquila is a partner with KCP&L in the jointly owned generating units Iatan Nos. 1 and 2, owning 18% of each Iatan generating unit. Direct costs of the acquisition incurred by Great

Plains Energy of $2.8 million at December 31, 2006, are deferred and will be included in purchase accounting treatment upon consummation of the acquisition.

4. RECEIVABLES

The Company's receivables are detailed in the following table.

	December 31	
	2006	2005
Consolidated KCP&L	(millions)	
Customer accounts receivable [(a)]	$ 35.2	$ 34.0
Allowance for doubtful accounts	(1.1)	(1.0)
Other receivables	80.2	37.3
Consolidated KCP&L receivables	114.3	70.3
Other Great Plains Energy		
Other receivables	229.2	193.0
Allowance for doubtful accounts	(4.1)	(4.3)
Great Plains Energy receivables	$ 339.4	$ 259.0

[(a)] Customer accounts receivable included unbilled receivables of $32.0 million and $31.4 million at December 31, 2006 and 2005, respectively.

Consolidated KCP&L's other receivables at December 31, 2006 and 2005, consisted primarily of receivables from partners in jointly owned electric utility plants and wholesale sales receivables. Great Plains Energy's other receivables at December 31, 2006 and 2005, consisted primarily of accounts receivable held by Strategic Energy, including unbilled receivables of $95.0 million and $99.9 million, respectively.

KCP&L sells all of its retail electric accounts receivable to its wholly owned subsidiary, Receivables Company, which in turn sells an undivided percentage ownership interest in the accounts receivable to Victory Receivables Corporation, an independent outside investor. KCP&L sells its receivables at a fixed price based upon the expected cost of funds and charge-offs. These costs comprise KCP&L's loss on the sale of accounts receivable. KCP&L services the receivables and receives an annual servicing fee of 2.5% of the outstanding principal amount of the receivables sold to Receivables Company. KCP&L does not recognize a servicing asset or liability because management determined the collection agent fee earned by KCP&L approximates market value.

Information regarding KCP&L's sale of accounts receivable to Receivables Company is reflected in the following tables.

2006	KCP&L	Receivables Company	Consolidated KCP&L
		(millions)	
Receivables (sold) purchased	$ (977.9)	$ 977.9	$ -
Gain (loss) on sale of accounts receivable [a]	(9.9)	9.9	-
Servicing fees	2.9	(2.9)	-
Fees to outside investor	-	(3.8)	(3.8)
Cash flows during the period			
Cash from customers transferred to Receivables Company	(980.7)	980.7	-
Cash paid to KCP&L for receivables purchased	974.6	(974.6)	-
Servicing fees	2.9	(2.9)	-
Interest on intercompany note	2.4	(2.4)	-

2005	KCP&L	Receivables Company	Consolidated KCP&L
		(millions)	
Receivables (sold) purchased	$ (599.7)	$ 599.7	$ -
Gain (loss) on sale of accounts receivable [a]	(6.0)	5.0	(1.0)
Servicing fees	1.4	(1.4)	-
Fees to outside investor	-	(1.4)	(1.4)
Cash flows during the period			
Cash from customers transferred to Receivables Company	(499.3)	499.3	-
Cash paid to KCP&L for receivables purchased	(494.3)	494.3	-
Servicing fees	1.4	(1.4)	-
Funds from outside investors [b]	70.0	-	70.0
Interest on intercompany note	0.9	(0.9)	-

[a] Any net gain (loss) is the result of the timing difference inherent in collecting receivables and over the life of the agreement will net to zero.

[b] During 2005, Receivables Company received $70 million cash from the outside investor for the sale of accounts receivable, which was then forwarded to KCP&L for consideration of its sale.

5. NUCLEAR PLANT

KCP&L owns 47% of WCNOC, the operating company for Wolf Creek, its only nuclear generating unit. Wolf Creek is regulated by the NRC, with respect to licensing, operations and safety-related requirements.

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. In July 2006, the DOE announced plans to submit a license application to the NRC for a nuclear waste repository at Yucca Mountain, Nevada, no later than June 30, 2008. The DOE also announced that if requested legislative changes are enacted, the repository could be able to accept spent nuclear fuel and high-level waste starting in early

2017. Management cannot predict when this site may be available for Wolf Creek. Under current DOE policy, once a permanent site is available, the DOE will accept spent nuclear fuel first from the owners with the older spent fuel. Wolf Creek has completed an on-site storage facility designed to hold all spent fuel generated at the plant through 2025. If the DOE meets its revised timetable for accepting spent fuel for disposal by 2017, management expects that the DOE could begin accepting some of Wolf Creek's spent fuel by 2025. Management can make no assurance that the DOE will meet its revised timetable and will continue to monitor this activity. See Note 15 for a related legal proceeding.

Nuclear Plant Decommissioning Costs
The MPSC and KCC require KCP&L and the other owners of Wolf Creek to submit an updated decommissioning cost study every three years and to propose funding levels.

The most recent study was submitted to the MPSC and KCC in 2005 and is the basis for the current cost of decommissioning estimates in the following table. In December 2006, KCP&L received orders from the MPSC and KCC, approving the funding schedules for this cost estimate based on an anticipated extension of the operating period to 2045.

	Total Station	KCP&L's 47% Share
	(millions)	
Current cost of decommissioning (in 2005 dollars)	$ 518	$ 243
Future cost of decommissioning (in 2045-2053 dollars) [a]	3,327	1,564
Annual escalation factor	4.40%	
Annual return on trust assets [b]	6.48%	

[a] Total future cost over an eight year decommissioning period.

[b] The 6.48% rate of return is thru 2025. The rate then systematically decreases through 2053 to 2.82% based on the assumption that the fund's investment mix will become increasingly more conservative as the decommissioning period approaches.

KCP&L currently contributes approximately $3.7 million annually to a tax-qualified trust fund to be used to decommission Wolf Creek. Amounts funded are charged to other operating expense and recovered in customers' rates. If the actual return on trust assets is below the anticipated level, management believes a rate increase would be allowed ensuring full recovery of decommissioning costs over the remaining life of the station.

The following table summarizes the change in Great Plains Energy's and consolidated KCP&L's decommissioning trust fund.

December 31	2006	2005
Decommissioning Trust	(millions)	
Beginning balance	$ 91.8	$ 84.1
Contributions	3.7	3.6
Realized gains	6.0	3.9
Unrealized gains	2.6	0.2
Ending balance	$ 104.1	$ 91.8

The decommissioning trust is reported at fair value on the balance sheets and is invested in assets as detailed in the following table.

	December 31	
Asset Category	**2006**	**2005**
Equity securities	43%	48%
Debt securities	54%	46%
Other	3%	6%
Total	100%	100%

Nuclear Liability and Insurance

The owners of Wolf Creek (Owners) maintain nuclear insurance for Wolf Creek in three areas: nuclear liability, nuclear 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 terrorism and related losses, as defined by the Terrorism Risk Insurance Act, 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, which was reauthorized through December 31, 2025, by the Energy Policy Act of 2005, 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 law, known as the Secondary Financial Protection (SFP) program. Under the SFP 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 $15 million ($7.1 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. In addition, the U.S. Congress could impose additional revenue-raising measures to pay claims.

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 approximately $26.1 million ($12.3 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 the other owners and could have a material adverse effect on KCP&L's results of operations, financial position 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.

After many years of effort, Nebraska regulators denied the facility developer's license application in December 1998, a prolonged lawsuit ensued, and Nebraska eventually settled the case by paying the Compact Commission $145.8 million in damages. The Compact Commission then paid pro rata portions of the settlement money to the various parties who originally funded the project. To date, WCNOC has received refunds totaling $21.3 million (KCP&L's 47% share being $10 million), including $1.7 million ($0.8 million, KCP&L's 47% share) received in 2006. The Compact Commission continues to explore alternative long-term waste disposal capability and has retained an insignificant portion of the settlement money. In April 2006, WCNOC and other affected generators filed a lawsuit in Federal District Court in Nebraska seeking to preserve their ability to continue to pursue their claim for their share of the retained amount plus interest. In January 2007, the court denied this claim stating the Compact Commission is still in existence, will continue to exist for the foreseeable future and has an arguable need for money.

Deferred Refueling Outage Costs
In September 2006, the FASB issued FASB Staff Position (FSP) No. AUG AIR-1, "Accounting for Planned Major Maintenance Activities." FSP No. AUG AIR-1 prohibits the use of the accrue-in-advance method of accounting for planned major maintenance activities. Management has elected to early adopt the provisions and accordingly has retrospectively adjusted prior periods. Prior to adoption, KCP&L utilized the accrue-in-advance method for incremental costs to be incurred during scheduled Wolf Creek refueling outages. KCP&L adopted the deferral method to account for operations and maintenance expenses incurred for scheduled refueling outages to be amortized evenly (monthly) over the unit's operating cycle of 18 months until the next scheduled outage. Replacement power costs during the outage will be expensed as incurred.

The overall impact to Great Plains Energy's and consolidated KCP&L's consolidated statements of income was no change to 2005 net income or earnings per share and a $1.7 million increase in 2004 net income, or $0.02 per share. The following line items within the consolidated statements of income were impacted by the change.

	As Originally Reported 2005	As Adjusted	Effect of Change	As Originally Reported 2004	As Adjusted	Effect of Change
Great Plains Energy			(millions)			
Fuel	$ 207.9	$ 208.4	$ 0.5	$ 179.4	$ 176.8	$ (2.6)
Other	327.7	327.7	-	324.2	323.6	(0.6)
Maintenance	90.3	90.0	(0.3)	83.6	84.1	0.5
Income taxes	(39.7)	(39.5)	0.2	(54.5)	(55.5)	(1.0)
Consolidated KCP&L						
Fuel	$ 207.9	$ 208.4	$ 0.5	$ 179.4	$ 176.8	$ (2.6)
Other	265.7	265.7	-	259.7	259.1	(0.6)
Maintenance	90.3	90.0	(0.3)	83.5	84.0	0.5
Income taxes	(48.2)	(48.0)	0.2	(52.8)	(53.8)	(1.0)

The overall impact to Great Plains Energy's and consolidated KCP&L's 2005 balance sheet was an increase in retained earnings of $10.6 million. For Great Plains Energy, this was a result of an increase in current and total assets of $8.1 million for the addition of deferred refueling outage costs and a decrease in current and total liabilities of $2.5 million for the elimination of accrued refueling outage costs (net of a $6.4 million increase in deferred income taxes). For consolidated KCP&L, this was a result of an increase in current and total assets of $1.7 million for the addition of deferred refueling outage costs (net of a $6.4 million decrease in deferred income taxes) and a decrease in current and total liabilities of $8.9 million for the elimination of accrued refueling outage costs.

As a result of the accounting change, Great Plains Energy's retained earnings as of January 1, 2005, increased to $462.1 million and consolidated KCP&L's retained earnings increased to $263.5 million. There were no overall impacts to the 2005 and 2004 statements of cash flows for Great Plains Energy and consolidated KCP&L.

6. REGULATORY MATTERS

KCP&L's Comprehensive Energy Plan

KCP&L continues to make progress in implementing its comprehensive energy plan under orders received from the MPSC and KCC in 2005. The Sierra Club and Concerned Citizens of Platte County have appealed the MPSC order, and the Sierra Club has appealed the KCC order. In March 2006, the Circuit Court of Cole County, Missouri, affirmed the MPSC order and the Sierra Club has appealed the decision to the Missouri Court of Appeals. The Kansas District Court denied the Sierra Club's appeal in May 2006 and the Sierra Club has appealed to the Kansas Court of Appeals. Although subject to the appeals, the MPSC and KCC orders remain in effect pending the applicable court's decision.

During 2006, KCP&L entered into certain procurement and engineering agreements for comprehensive energy plan projects, and further refined its cost estimates and schedules as contracting and engineering progressed. The following table summarizes the comprehensive energy plan estimated capital expenditures.

Project	Estimated Capital Expenditures [a]
	(millions)
Iatan No. 2 [b]	$ 837 - $ 914
Environmental Retrofit Projects [c]	423 - 443
Wind Generation [d]	164
Asset Management	42
Customer Programs	53
Total	$ 1,519 - $ 1,616

[a] KCP&L share of costs, exclusive of AFDC.
[b] KCP&L's 54.71% ownership (approximately 465MW) of an estimated 850MW plant.
[c] These projects are the Iatan No. 1 air quality control project, the LaCygne No. 1 selective catalytic reduction project and baghouse and scrubber project.
[d] The Spearville Wind Energy Facility went into service in September 2006.

The cost estimates for Iatan No. 2 and the environmental retrofits include a range for contingencies on those projects that reflect, among other factors, the current level of contracting. Specific comprehensive energy plan project management and other risk mitigation practices result in varying uncertainty and therefore a range of contingency allowance has been provided. The upper end of each range reflects a contingency allowance that management believes is consistent with industry practice and market conditions for projects of these types, sizes and degree of completion.

Because of the magnitude of the comprehensive energy plan projects and the length of the implementation period, the actual expenditures, scope and timing of any or all of these projects that have not been completed may differ materially from these estimates.

KCP&L Regulatory Proceedings

In February 2006, KCP&L filed requests with the MPSC and KCC for annual rate increases of $55.8 million or 11.5% and $42.3 million or 10.5%, respectively. The requests were based on a return on equity of 11.5% and an adjusted equity ratio of 53.8%. KCP&L received rate orders from the MPSC and KCC in December 2006. The ordered rates were implemented January 1, 2007.

The MPSC ordered an approximate $51 million increase in annual revenues effective January 1, 2007, reflecting an authorized return on equity of 11.25%. Approximately $22 million of the rate increase results from additional amortization to help maintain cash flow levels. The MPSC order established, for regulatory purposes, annual pension cost recovery for the period beginning January 1, 2007, of approximately $19 million on a Missouri jurisdictional basis, after allocations to the other joint owners of generation facilities and capitalized amounts, through the creation of a regulatory asset or liability. The order also established, effective January 1, 2006, a regulatory asset or liability as appropriate for amounts arising from defined benefit plan settlements and curtailments to be amortized over a five-year period beginning with the effective date of rates approved in KCP&L's next rate case.

The KCC ordered a $29 million increase in annual revenues effective January 1, 2007, including $4 million of accelerated depreciation to maintain cash flow levels. The KCC order does not propose an energy cost adjustment (ECA) clause; however, KCP&L agreed to propose an ECA clause in its next rate case to be filed no later than March 1, 2007. The ordered rates were implemented January 1, 2007. The KCC order established, for regulatory purposes, annual pension costs beginning January 1, 2007, of approximately $19 million on a Kansas jurisdictional basis through the creation of a regulatory asset or liability. The order also established, effective January 1, 2006, a regulatory asset or liability as appropriate for amounts arising from defined benefit plan settlements and curtailments to be amortized over a five-year period beginning with the effective date of rates approved in KCP&L's next rate case.

See Regulatory Assets and Liabilities below for information regarding various regulatory assets established at December 31, 2006, in accordance with these rate orders.

Regulatory Assets and Liabilities

KCP&L is subject to the provisions of SFAS No. 71 and has recorded assets and liabilities on its balance sheet resulting from the effects of the ratemaking process, which would not otherwise be recorded under GAAP. Regulatory assets represent incurred costs that are probable of recovery from future revenues. Regulatory liabilities represent amounts imposed by rate actions of KCP&L's regulators that may require refunds to customers, represent amounts provided in current rates that are intended to recover costs that are expected to be incurred in the future for which KCP&L remains accountable, or represent a gain or other reduction of allowable costs to be given to customers over future periods. Future recovery of regulatory assets is not assured, but is generally subject to review by regulators in rate proceedings for matters such as prudence and reasonableness. Future reductions in revenue or refunds for regulatory liabilities generally are not mandated, pending future rate proceedings or actions by the regulators. Management regularly assesses whether regulatory assets and liabilities are probable of future recovery or refund by considering factors such as decisions by the MPSC, KCC or FERC on KCP&L's rate case filings; decisions in other regulatory proceedings, including decisions related to other companies that establish precedent on matters applicable to KCP&L; and changes in laws and regulations. If recovery or refund of regulatory assets or liabilities is not approved by regulators or is no longer deemed probable, these regulatory assets or liabilities are recognized in the current period results of operations. KCP&L's continued ability to meet the criteria for application of SFAS No. 71 may be affected in the future by restructuring and deregulation in the electric industry. In the event that SFAS No. 71 no longer applied to a deregulated 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 the requirements of SFAS No. 144.

	December 31	
	2006	2005
Regulatory Assets	(millions)	
Taxes recoverable through future rates	$ 81.7	$ 85.7
Decommission and decontaminate federal uranium enrichment facilities	0.6	1.3
Loss on reacquired debt	6.4	7.1
January 2002 incremental ice storm costs (Missouri)	0.4	4.9
Change in depreciable life of Wolf Creek	45.4	27.4
Cost of removal	8.2	9.3
Asset retirement obligations	16.9	23.6
Pension and post-retirement costs	256.9	15.6
Surface Transportation Board litigation expenses	1.7	-
Deferred customer programs	5.9	0.3
2006 rate case expenses	2.6	0.2
Other	7.7	4.5
Total	$ 434.4	$ 179.9
Regulatory Liabilities		
Emission allowances	$ 64.5	$ 64.3
Pension costs	-	1.0
Asset retirement obligations	35.6	-
Additional Wolf Creek amortization (Missouri)	14.6	4.3
Total	$ 114.7	$ 69.6

Except as noted below, regulatory assets for which costs have been incurred have been included (or are expected to be included, for costs incurred subsequent to the most recently approved rate case) in KCP&L's rate base, thereby providing a return on invested costs. Certain regulatory assets do not result from cash expenditures and therefore do not represent investments included in rate base or have offsetting liabilities that reduce rate base. The regulatory asset for pension and post-retirement costs at December 31, 2006, includes $25.0 million, net of related liabilities, for the adoption of SFAS No. 158 representing the difference between funding and expenses recognized of the pension and post-retirement plans that are not included in rate base. The regulatory asset for pension and post-retirement costs at December 31, 2006, includes $11.6 million of amounts arising from defined benefit plan settlements and curtailments that are not included in rate base to be amortized over a five-year period beginning with the effective date of rates approved in KCP&L's next rate case. The regulatory asset for pension and post-retirement costs at December 31, 2006, includes $9.0 million representing an accounting method difference and is not included in rate base. Certain insignificant items in Regulatory Assets – Other are also not included in rate base.

Great Plains Energy and consolidated KCP&L recognized several new regulatory assets in accordance with the 2006 rate orders received from the MPSC and KCC including, but not limited to, amounts arising from defined benefit plan settlements and curtailments, litigation costs related to the KCP&L rate complaint case filed with the Surface Transportation Board (STB), deferred costs incurred in relation to various demand response, efficiency and affordability customer programs, and 2006 Missouri & Kansas rate case expenses.

Southwest Power Pool Regional Transmission Organization

KCP&L is a member of the Southwest Power Pool (SPP), which is a FERC approved Regional Transmission Organization (RTO). In July 2006, KCC granted interim approval for KCP&L to take SPP network integration transmission service for its retail customers. During 2006, KCC and MPSC both issued orders approving KCP&L's participation in the SPP RTO, which also made final the previously

granted KCC interim approval. In May 2006, SPP made a compliance filing in response to a previously issued FERC order on the SPP energy imbalance service market. In July 2006, FERC issued an order on the compliance filing accepting in part, as modified, and rejecting in part the filing, permitting the start of the SPP energy imbalance service market no earlier than October 1, 2006, and required SPP to make additional filings. The SPP Board met in October 2006 and delayed SPP's readiness filing to FERC. In December 2006, the SPP Board voted to file the certification of SPP's market readiness for a February 1, 2007, start. FERC issued an order concerning the December market readiness filing on January 26, 2007. In this order, FERC accepted the market readiness filing and authorized the SPP to start the energy imbalance service market on February 1, 2007. KCP&L is participating in this market.

Revenue Sufficiency Guarantee

Since the April 2005 implementation of Midwest Independent Transmission System Operator Inc. (MISO) market operations, MISO's business practice manuals and other instructions to market participants have stated that Revenue Sufficiency Guarantee (RSG) charges will not be imposed on day-ahead virtual offers to supply power not supported by actual generation. RSG charges are collected by MISO in order to compensate generators that are standing by to supply electricity when called upon by MISO. In April 2006, FERC issued an order regarding MISO RSG charges. In its order, FERC interpreted MISO's tariff to require that virtual supply offers be included in the calculation of RSG charges and that to the extent that MISO did not charge market participants RSG charges on virtual supply offers, MISO violated its tariff. The FERC order required MISO to recalculate RSG rates back to April 1, 2005, and make refunds to customers who paid RSG charges on imbalances, with interest, reflecting the recalculated charges. In order to make such refunds, RSG charges could have been retroactively imposed on market participants who submitted virtual supply offers during the recalculation period.

Strategic Energy is among the MISO participants that paid RSG charges on imbalances and could have received a refund as a result of the order. Strategic Energy could also have been subject to a retroactive assessment from MISO for RSG charges on virtual supply offers it submitted during the recalculation period. Consistent with MISO's business practice manuals, management does not believe Strategic Energy should be assessed RSG charges retroactively or prospectively on its virtual supply offers.

Numerous requests for rehearing were filed and in October 2006, FERC entered an order granting requests for rehearing of the FERC's decision to require MISO to retroactively recalculate RSG charges and provide refunds to customers that paid RSG charges on imbalances. As a result, MISO will not assess RSG charges retroactively on virtual supply offers, but RSG charges will apply prospectively on certain virtual supply offers. Parties have petitioned to appeal and move for further rehearing of the FERC order. Management is unable to predict the outcome of any appeals or further requests for rehearing.

Seams Elimination Charge Adjustment

Seams Elimination Charge Adjustment (SECA) is a transitional pricing mechanism authorized by FERC and intended to compensate transmission owners for the revenue lost as a result of FERC's elimination of regional through and out rates between PJM Interconnection, LLC (PJM) and MISO during a 16-month transition period from December 1, 2004, through March 31, 2006. Each relevant PJM and MISO zone and the load-serving entities within that zone were allocated a portion of SECA based on transmission services provided to that zone during 2002 and 2003. In 2006, Strategic Energy recorded a reduction of purchased power expense of $2.4 million for SECA recoveries from suppliers, which offset $2.7 million of expense recorded in the first quarter. During 2005, Strategic Energy recorded purchased power expenses totaling $13.6 million for SECA transition charges. Strategic Energy recovered $1.3 million and $5.4 million in 2006 and 2005, respectively, of its SECA costs through

billings to its retail customers. No further billings are anticipated pending the outcome of proceedings discussed below.

There are several unresolved matters and legal challenges related to SECA that are pending before FERC on rehearing. FERC established a schedule for resolution of certain SECA issues, including the issue of shifting SECA allocations to the shipper. The shipper in Strategic Energy's situation is the wholesale supplier, which, through a contract with Strategic Energy, delivered power to various zones in which Strategic Energy was supplying retail customers. In most instances, the shipper was the purchaser of through and out transmission service and therefore included the cost of the through and out rate in its energy price.

In 2006, FERC held hearings on the justness and reasonableness of the SECA rate and on attempts by suppliers to shift SECA to wholesale counterparties and subsequently, a favorable initial decision was extended by an administrative law judge, which could potentially result in a refund of prior SECA payments. Management is awaiting FERC action and is unable to predict the outcome of legal and regulatory challenges to the SECA mechanism.

7. GOODWILL AND INTANGIBLE PROPERTY

Great Plains Energy's consolidated balance sheets reflect goodwill associated with the Company's ownership in Strategic Energy of $88.1 million and $87.6 million at December 31, 2006 and 2005, respectively. The increase in goodwill in 2006 reflects Great Plains Energy's acquisition of the remaining indirect interest in Strategic Energy as part of a litigation settlement. See Note 15 for additional information. Annual impairment tests, conducted September 1, have been completed and there were no impairments of goodwill in 2006, 2005 or 2004.

Other Intangible Assets and Related Liabilities
Great Plains Energy and consolidated KCP&L's intangible assets and related liabilities are detailed in the following table.

	December 31, 2006		December 31, 2005	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
		(millions)		
Consolidated KCP&L				
Computer software [(a)]	$ 100.4	$ (76.2)	$ 92.9	$ (68.8)
Other Great Plains Energy				
Computer software [(a)]	15.0	(8.4)	12.0	(5.2)
Acquired intangible assets				
Supply contracts	26.5	(26.5)	26.5	(19.3)
Customer relationships	17.0	(7.6)	17.0	(4.7)
Asset information systems	1.9	(1.4)	1.9	(0.9)
Unamortized intangible assets				
Strategic Energy trade name	0.7		0.7	
Total intangible assets	$ 161.5	$ (120.1)	$ 151.0	$ (98.9)
Amortized related liabilities				
Retail contracts	$ 26.5	$ (26.5)	$ 26.5	$ (19.3)

[(a)] Computer software is included in electric utility plant or other nonutility property, as applicable, on the consolidated balance sheets.

The fair value of acquired supply (intangible asset) and retail (liability) contracts were amortized over 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.

Amortization expense for the acquired share of intangible assets and related liabilities is detailed in the following table.

				Estimated Amortization Expense			
	2006	2005	2004	2007	2008	2009	2010
				(millions)			
Intangible assets	$ 10.6	$ 15.0	$ 9.9	$ 3.3	$ 2.8	$ 2.9	$ 0.9
Related liabilities	(7.2)	(11.6)	(7.7)	-	-	-	-
Net amortization expense	$ 3.4	$ 3.4	$ 2.2	$ 3.3	$ 2.8	$ 2.9	$ 0.9

8. PENSION PLANS, OTHER EMPLOYEE BENEFITS AND SKILL SET REALIGNMENT COSTS

Pension Plans and Other Employee Benefits
The Company maintains defined benefit pension plans for substantially all employees, including officers, of KCP&L, Services and WCNOC. Pension benefits under these plans reflect the employees' compensation, years of service and age at retirement.

The MPSC and KCC issued orders in 2005 establishing regulatory assets and liabilities for the difference between KCP&L's pension costs for ratemaking and SFAS No. 87 pension costs. In 2006, the Commissions issued orders granting equivalent treatment for SFAS No. 88 charges retroactive to January 1, 2006.

In addition to providing pension benefits, the Company provides certain post-retirement health care and life insurance benefits for substantially all retired employees of KCP&L, Services and WCNOC. The

cost of post-retirement benefits charged to KCP&L are accrued during an employee's years of service and recovered through rates.

In September 2006, SFAS No. 158 was issued which requires the recognition of the funded status of defined pension plans and other post-retirement plans on the balance sheet with any changes in funded status recognized through comprehensive income in the year the changes occur and is effective for fiscal years ending after December 15, 2006, with retrospective application not permitted. SFAS No. 158 also requires an employer to measure the funded status of a plan as of the date of its year-end balance sheet effective for fiscal years ending after December 15, 2008. Under the standard, overfunded plans are recognized as an asset and underfunded plans are recognized as a liability with any unrecognized amounts recorded in accumulated other comprehensive income (OCI). The recognition of any additional minimum pension liability and related intangible asset are no longer required. The Company adopted the recognition requirements of SFAS No. 158 on December 31, 2006, and established a regulatory asset in accordance with SFAS No. 71 for the amounts KCP&L recorded in accumulated OCI. Prior to the adoption of SFAS No. 158, the Company decreased the minimum pension liability adjustment, intangible asset and OCI, net of tax by $27.8 million, $2.3 million and $16.0 million, respectively.

The following table summarizes the effects of implementing SFAS No. 158 on Great Plains Energy's and consolidated KCP&L's balance sheets at December 31, 2006.

December 31, 2006	Prior to SFAS No. 158	Adjustments	Post SFAS No. 158
		(millions)	
Prepaid benefit cost	$ 46.8	$ (46.8)	$ -
Current liability	-	(1.0)	(1.0)
Accrued benefit cost	(31.4)	31.4	-
Pension liability	-	(143.2)	(143.2)
Postretirement liability	-	(33.0)	(33.0)
Minimum pension liability adjustment	(46.5)	46.5	-
Intangible asset	12.1	(12.1)	-
Accumulated OCI, net of tax	-	1.6	1.6
Regulatory asset	34.3	155.7	190.0

The following pension benefits tables provide information relating to the funded status of all defined benefit pension plans on an aggregate basis as well as the components of net periodic benefit costs. The plan measurement date for the majority of plans is September 30. In 2006, contributions of $1.2 million and $4.6 million were made to the pension and post-retirement benefit plans, respectively, after the measurement date and in 2005, contributions of $0.2 million and $3.8 million were made to the pension plan and post-retirement 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	
	2006	2005	2006	2005
Change in projected benefit obligation (PBO)		(millions)		
PBO at beginning of year	$ 554.6	$ 515.7	$ 53.0	$ 49.1
Service cost	18.8	17.3	0.9	0.9
Interest cost	30.9	29.8	3.0	2.9
Contribution by participants	-	-	1.3	1.2
Amendments	-	0.6	-	-
Actuarial loss (gain)	6.5	33.0	(1.8)	3.6
Benefits paid	(17.9)	(41.2)	(4.2)	(4.1)
Benefits paid by Company	(0.4)	(0.6)	(0.7)	(0.6)
Settlements paid	(83.7)	-	-	-
PBO at end of plan year	$ 508.8	$ 554.6	$ 51.5	$ 53.0
Change in plan assets				
Fair value of plan assets at beginning of year	$ 412.2	$ 370.5	$ 12.2	$ 14.7
Actual return on plan assets	34.3	47.8	0.6	0.3
Contributions by employer and participants	18.8	35.1	4.8	1.3
Benefits paid	(17.9)	(41.2)	(4.2)	(4.1)
Settlements paid	(82.9)	-	-	-
Fair value of plan assets at end of plan year	$ 364.5	$ 412.2	$ 13.4	$ 12.2
Funded status at end of year				
Funded status	$(144.3)	$(142.4)	$ (38.1)	$ (40.8)
Unrecognized actuarial loss	-	195.0	-	14.1
Unrecognized prior service cost	-	32.6	-	0.8
Unrecognized transition obligation	-	0.3	-	8.2
Contributions and changes after measurement date	0.6	0.2	4.6	3.8
Net amounts recognized	(143.7)	85.7	(33.5)	(13.9)
Regulatory asset, net	-	14.6	-	-
Net amount recognized at December 31	$(143.7)	$ 100.3	$ (33.5)	$ (13.9)
Amounts recognized in the consolidated balance sheets				
Prepaid benefit cost	$ -	$ 98.3	$ -	$ -
Current pension liability	(0.5)	-	(0.5)	-
Accrued benefit cost	-	(12.8)	-	(17.7)
Pension liability	(143.8)	-	(37.6)	-
Minimum pension liability adjustment	-	(74.3)	-	-
Intangible asset	-	14.4	-	-
Contributions and changes after measurement date	0.6	0.2	4.6	3.8
Net amount recognized before regulatory treatment	(143.7)	25.8	(33.5)	(13.9)
Accumulated OCI	2.3	59.9	0.3	-
Regulatory asset, net	238.0	14.6	18.9	-
Net amount recognized at December 31	$ 96.6	$ 100.3	$ (14.3)	$ (13.9)
Amounts in accumulated OCI or regulatory asset not yet recognized as a component of net periodic cost:				
Unrecognized actuarial loss	$ 144.8	$ -	$ 11.6	$ -
Unrecognized prior service cost	28.3	-	0.6	-
Unrecognized transition obligation	0.3	-	7.0	-
Other	66.9	-	-	-
Net amount recognized at December 31	$ 240.3	$ -	$ 19.2	$ -

Year to Date December 31	Pension Benefits 2006	2005	2004	Other Benefits 2006	2005	2004
Components of net periodic benefit cost			(millions)			
Service cost	$ 18.8	$ 17.3	$ 16.7	$ 0.9	$ 0.9	$ 0.9
Interest cost	30.9	29.8	30.1	3.0	2.9	3.1
Expected return on plan assets	(32.7)	(32.4)	(31.7)	(0.6)	(0.6)	(0.6)
Amortization of prior service cost	4.3	4.3	4.3	0.2	0.2	0.2
Recognized net actuarial loss	31.8	18.6	7.7	0.9	0.5	0.7
Transition obligation	0.1	0.1	0.1	1.2	1.2	1.2
Settlement charges	23.1	-	1.8	-	-	-
Net periodic benefit cost before regulatory adjustment	76.3	37.7	29.0	5.6	5.1	5.5
Regulatory adjustment	(52.3)	(14.6)	-	-	-	-
Net periodic benefit cost	$ 24.0	$ 23.1	$ 29.0	$ 5.6	$ 5.1	$ 5.5

The estimated prior service cost, net loss and transition costs for the defined benefit plans that will be amortized from accumulated OCI or a regulatory asset into net periodic benefit cost in 2007 are $4.3 million, $35.2 million and $0.1 million, respectively. The estimated prior service cost, net loss, and transition costs for the other post-retirement benefit plans that will be amortized from accumulated OCI or a regulatory asset into net periodic benefit cost in 2007 are $0.2 million, $0.6 million and $1.2 million, respectively. Net actuarial gains and losses are recognized on a rolling five-year average basis.

The accumulated benefit obligation (ABO) for all defined benefit pension plans was $427.1 million and $469.9 million at December 31, 2006 and 2005, respectively. The PBO, ABO and the fair value of plan assets at plan year-end are aggregated by funded and under funded plans in the following table.

	2006	2005
Pension plans with the ABO in excess of plan assets	(millions)	
Projected benefit obligation	$ 323.9	$ 337.8
Accumulated benefit obligation	268.5	280.6
Fair value of plan assets	193.4	204.1
Pension plans with plan assets in excess of the ABO		
Projected benefit obligation	$ 184.9	$ 216.8
Accumulated benefit obligation	158.6	189.3
Fair value of plan assets	171.1	208.1

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 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		Other Benefits	
	2006	2005	2006	2005
Discount rate	5.87%	5.62%	5.89%	5.62%
Rate of compensation increase	3.81%	3.57%	3.90%	3.60%

Weighted average assumptions used to determine net costs for years ended at December 31	Pension Benefits		Other Benefits	
	2006	2005	2006	2005
Discount rate	5.62%	5.82%	5.62%	5.82%
Expected long-term return on plan assets	8.25%	8.75%	4.23% *	4.26% *
Rate of compensation increase	3.57%	3.06%	3.60%	3.05%

* after tax

Pension plan assets are managed in accordance with "prudent investor" guidelines contained in the Employee Retirement Income Security Act (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, 2006 and 2005, respectively, the fair value of plan assets was $364.5 million, not including a $1.2 million contribution made after the plan year-end, and $412.2 million, not including a $0.2 million subsequent contribution. The asset allocation for the Company's pension plans at the end of 2006 and 2005, and the target allocation for 2007 are reported in the following table. The portfolio is periodically rebalanced to generally meet target allocation percentages.

Asset Category	Target Allocation	Plan Assets at December 31	
		2006	2005
Equity securities	62%	67%	61%
Debt securities	28%	22%	26%
Real estate	6%	6%	7%
Other	4%	5%	6%
Total	100%	100%	100%

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. The cost trend assumed for 2006 was 9% and is 8% for 2007. The cost trend rate will continue to decline through 2010 to the ultimate cost trend rate of 5%. The health care plan requires retirees to make monthly contributions on behalf of themselves and their dependents in an amount determined by the Company.

The effects of a one-percentage point change in the assumed health care cost trend rates, holding all other assumptions constant, at December 31, 2006, are detailed in the following table.

	Increase	Decrease
	(millions)	
Effect on total service and interest component	$ 0.1	$ (0.1)
Effect on postretirement benefit obligation	0.7	(0.6)

The Company expects to contribute $33.6 million to the plans in 2007 to meet ERISA funding requirements, all of which will be paid by KCP&L. The Company will also contribute $4.3 million to other post-retirement benefit plans in 2007, $4.0 million of which will be paid by KCP&L. The Company's funding policy is to contribute amounts sufficient to meet the ERISA minimum funding requirements plus additional amounts as considered 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 2016.

	Pension Benefits	Other Benefits
	(millions)	
2007	$ 37.2	$ 7.0
2008	36.2	7.6
2009	36.4	8.3
2010	39.7	8.9
2011	38.6	9.6
2012-2016	222.2	56.3

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 approximately $4.8 million in 2006, 2005 and 2004. Consolidated KCP&L's annual cost of the plans was approximately $3.0 million for each of the last three years.

Cash-Based Long-Term Incentives

Strategic Energy has long-term incentives designed to reward officers and key members of management with Great Plains Energy restricted stock (issued under the Company's Long-Term Incentive Plan) and a cash performance payment for achieving specific performance goals over stated periods of time, commencing January 1, 2005. The restricted stock compensation expense is discussed in Note 9. In 2006 and 2005, compensation expense of $3.8 million and $1.6 million, respectively, was recognized for the cash-based incentives.

Skill Set Realignment Costs

In 2005 and early 2006, management undertook a process to assess, improve and reposition the skill sets of employees for implementation of the comprehensive energy plan. In 2006, Great Plains Energy and consolidated KCP&L recorded $9.4 million and $9.3 million, respectively, related to this process reflecting severance, benefits and related payroll taxes provided to employees.

9. EQUITY COMPENSATION

As of January 1, 2006, the Company adopted SFAS No. 123 (revised 2004), "Share-Based Payment" using the modified prospective application method. The adoption of SFAS No. 123R had an insignificant effect on the companies' consolidated statements of income and cash flows in 2006.

The Company's Long-Term Incentive Plan is an equity compensation plan approved by its shareholders. KCP&L does not have an equity compensation plan; however, KCP&L officers participate in Great Plains Energy's Long-Term Incentive Plan. The Long-Term Incentive Plan permits the grant of restricted stock, stock options, limited stock appreciation rights and performance shares to officers 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. Common stock shares delivered by the Company under the Long-Term Incentive Plan may be authorized but unissued, held in the treasury or purchased on the open market (including private purchases) in accordance with applicable security

laws. The Company has a policy of delivering newly issued shares, or shares surrendered by Long-Term Incentive Plan participants on account of withholding taxes and held in treasury, or both, to satisfy share option exercises and does not expect to repurchase common shares during 2007 to satisfy stock option exercises.

SFAS No. 123R requires forfeitures to be estimated. Forfeiture rates are based on historical forfeitures and future expectations and are reevaluated annually. The following table summarizes Great Plains Energy's and KCP&L's equity compensation expense and associated income tax benefits.

	2006	2005	2004
Compensation expense		(millions)	
Great Plains Energy	$ 3.9	$ 2.8	$ 0.8
KCP&L	2.4	1.7	0.6
Income tax benefits			
Great Plains Energy	1.2	1.1	0.4
KCP&L	0.8	0.6	0.2

Stock Options Granted 2001 – 2003

Stock options were granted under the plan at 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. 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. Compensation expense and accrued dividends related to stock options are recognized over the stated vesting period. Exercise prices range from $24.90 to $27.73 and all stock options are fully vested and have a remaining weighted average contractual term of 4.9 years at December 31, 2006. All stock option activity in 2006 is summarized in the following table.

Stock Options	Shares	Exercise Price*
Beginning balance	111,455	$ 25.56
Forfeited or expired	(1,983)	27.73
Exercisable at December 31	109,472	25.52

* weighted-average

Performance Shares

The payment of performance shares is contingent upon achievement of specific performance goals over a stated period of time as approved by the Compensation and Development Committee of the Company's Board of Directors. The number of performance shares ultimately paid can vary from the number of shares initially granted depending on Company performance, based on internal and external measures, over stated performance periods. Performance shares have a value equal to the market value of the shares on the grant date with accruing dividends. Compensation expense, calculated by multiplying shares by the related grant-date fair value less the present value of dividends, and accrued dividends related to performance shares are recognized over the stated period.

Performance share activity for 2006 is summarized in the following table.

Performance	Shares	Grant Date Fair Value *
Beginning balance	172,761	$ 30.17
Performance adjustment	(2,650)	
Granted	94,159	28.20
Issued	(9,499)	27.73
Ending balance	254,771	29.56

* weighted-average

At December 31, 2006, the remaining weighted-average contractual term was 1.1 years. The weighted-average grant-date fair value of shares granted was $28.20 and $30.34 in 2006 and 2005, respectively. There were no performance shares granted during 2004. At December 31, 2006, there was $2.2 million of total unrecognized compensation expense, net of forfeiture rates, related to performance shares granted under the Long-Term Incentive Plan, which will be recognized over the remaining weighted-average contractual term. The total fair value of shares issued was insignificant during 2006 and performances shares were not issued during 2005 and 2004.

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 issue date. Restricted stock shares vest over a stated period of time with accruing reinvested dividends. Compensation expense, calculated by multiplying shares by the related grant-date fair value less the present value of dividends, and accrued dividends related to restricted stock are recognized over the stated vesting period. Restricted stock activity for 2006 is summarized in the following table.

Nonvested Restricted stock	Shares	Grant Date Fair Value *
Beginning balance	119,966	$ 30.50
Issued	48,041	28.22
Vested	(25,404)	30.49
Forfeited	(2,000)	28.20
Ending balance	140,603	29.75

* weighted-average

At December 31, 2006, the remaining weighted-average contractual term was 1.4 years. The weighted-average grant-date fair value of shares granted was $28.22, $30.47 and $29.71 during 2006, 2005 and 2004, respectively. At December 31, 2006, there was $1.5 million of total unrecognized compensation expense, net of forfeiture rates, related to nonvested restricted stock granted under the Long-Term Incentive Plan, which will be recognized over the remaining weighted-average contractual term. The total fair value of shares vested was $0.8 million, $0.8 million and $1.5 million in 2006, 2005 and 2004, respectively.

10. TAXES

Components of income taxes are detailed in the following tables.

Great Plains Energy	2006	As Adjusted 2005	As Adjusted 2004
Current income taxes		(millions)	
Federal	$ 59.2	$ 64.3	$ 19.9
State	0.9	1.3	13.3
Total	60.1	65.6	33.2
Deferred income taxes			
Federal	(7.2)	(4.2)	46.8
State	(3.8)	(19.0)	(15.5)
Total	(11.0)	(23.2)	31.3
Investment tax credit amortization	(1.2)	(3.9)	(4.0)
Total income tax expense	47.9	38.5	60.5
Less: taxes on discontinued operations			
Current tax (benefit) expense	-	(1.0)	(5.0)
Deferred tax (benefit) expense	-	-	10.0
Income taxes on continuing operations	$ 47.9	$ 39.5	$ 55.5

Consolidated KCP&L	2006	As Adjusted 2005	As Adjusted 2004
Current income taxes		(millions)	
Federal	$ 49.3	$ 79.9	$ 39.2
State	4.8	5.6	6.7
Total	54.1	85.5	45.9
Deferred income taxes			
Federal	15.6	(14.3)	23.2
State	1.8	(19.3)	(11.3)
Total	17.4	(33.6)	11.9
Investment tax credit amortization	(1.2)	(3.9)	(4.0)
Total	$ 70.3	$ 48.0	$ 53.8

Income Tax Expense and Effective Income Tax Rates

Income tax expense and the effective income tax rates reflected in continuing operations in the financial statements and the reasons for their differences from the statutory federal rates are detailed in the following tables.

	Income Tax Expense			Income Tax Rate		
Great Plains Energy	**2006**	**As Adjusted 2005**	**As Adjusted 2004**	**2006**	**As Adjusted 2005**	**As Adjusted 2004**
		(millions)				
Federal statutory income tax	$ 61.4	$ 71.3	$ 80.8	35.0 %	35.0 %	35.0 %
Differences between book and tax depreciation not normalized	(0.3)	2.3	1.4	(0.2)	1.1	0.6
Amortization of investment tax credits	(1.2)	(3.9)	(4.0)	(0.7)	(1.9)	(1.7)
Federal income tax credits	(9.3)	(10.0)	(12.8)	(5.3)	(4.9)	(5.5)
State income taxes	0.5	2.7	7.9	0.3	1.3	3.4
Changes in uncertain tax positions, net	0.1	(7.9)	(3.4)	-	(3.9)	(1.5)
Rate change on deferred taxes	-	(11.7)	(8.6)	-	(5.8)	(3.7)
Valuation allowance	-	-	0.5	-	-	0.2
Other	(3.3)	(3.3)	(6.3)	(1.8)	(1.5)	(2.8)
Total	$ 47.9	$ 39.5	$ 55.5	27.3 %	19.4 %	24.0 %

	Income Tax Expense			Income Tax Rate		
Consolidated KCP&L	**2006**	**As Adjusted 2005**	**As Adjusted 2004**	**2006**	**As Adjusted 2005**	**As Adjusted 2004**
		(millions)				
Federal statutory income tax	$ 76.9	$ 67.0	$ 69.6	35.0 %	35.0 %	35.0 %
Differences between book and tax depreciation not normalized	(0.3)	2.3	1.4	(0.2)	1.2	0.7
Amortization of investment tax credits	(1.2)	(3.9)	(4.0)	(0.6)	(2.0)	(2.0)
Federal income tax credits	(4.6)	-	-	(2.1)	-	-
State income taxes	5.5	4.2	7.0	2.5	2.2	3.6
Changes in uncertain tax positions, net	0.6	(1.7)	(2.7)	0.3	(0.9)	(1.4)
Parent company tax benefits	(4.7)	(5.4)	(5.9)	(2.1)	(2.8)	(2.9)
Rate change on deferred taxes	-	(11.7)	(8.6)	-	(6.1)	(4.3)
Other	(1.9)	(2.8)	(3.0)	(0.8)	(1.6)	(1.7)
Total	$ 70.3	$ 48.0	$ 53.8	32.0 %	25.0 %	27.0 %

During 2005, Great Plains Energy and consolidated KCP&L's income tax expense decreased by $7.5 million and $6.3 million, respectively, due to the favorable impact of sustained audited positions on the companies' composite tax rates. Great Plains Energy's income tax expense was also reduced by $5.7 million due to events during 2005 that strengthened the probability of sustaining tax deductions taken on previously filed tax returns.

SFAS No. 109 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 effective income tax rates in 2005 and 2004 was the result of adjusting KCP&L's deferred tax balance to its lower composite tax rate due to the impact of sustained audited positions and state tax planning. The impact of the composite tax rate reductions on the deferred tax balances resulted in

tax benefits for Great Plains Energy and consolidated KCP&L of $11.7 million in 2005 and $8.6 million in 2004.

Deferred Income Taxes

The tax effects of major temporary differences resulting in deferred income tax assets (liabilities) in the consolidated balance sheets are in the following tables.

	Great Plains Energy		Consolidated KCP&L	
December 31	**2006**	**As Adjusted 2005**	**2006**	**As Adjusted 2005**
		(millions)		
Current deferred income taxes				
Nuclear fuel outage	$ (5.2)	$ (3.0)	$ (5.2)	$ (3.0)
Derivative instruments	34.1	(11.2)	0.2	-
Accrued vacation	4.5	4.7	4.4	4.7
Other	6.2	1.8	0.7	0.8
Net current deferred income tax asset (liability)	39.6	(7.7)	0.1	2.5
Noncurrent deferred income taxes				
Plant related	(566.3)	(554.2)	(566.3)	(554.2)
Income taxes on future regulatory recoveries	(81.7)	(85.7)	(81.7)	(85.7)
Derivative instruments	19.3	(11.1)	(4.3)	(4.5)
Pension and postretirement benefits	(28.9)	(8.0)	(31.2)	(8.4)
Storm related costs	(0.1)	(1.9)	(0.1)	(1.9)
Debt issuance costs	(2.5)	(2.7)	(2.5)	(2.7)
Gas properties related	(1.1)	(1.3)	-	-
SO_2 emission allowance sales	24.5	24.2	24.5	24.2
Tax credit carryforwards	15.0	16.0	-	-
State net operating loss carryforward	0.5	0.5	-	-
Other	(0.8)	3.3	1.6	6.2
Net noncurrent deferred tax liability before valuation allowance	(622.1)	(620.9)	(660.0)	(627.0)
Valuation allowance	(0.5)	(0.5)	-	-
Net noncurrent deferred tax liability	(622.6)	(621.4)	(660.0)	(627.0)
Net deferred income tax liability	$ (583.0)	$ (629.1)	$ (659.9)	$ (624.5)

	Great Plains Energy		Consolidated KCP&L	
December 31	**2006**	**As Adjusted 2005**	**2006**	**As Adjusted 2005**
		(millions)		
Gross deferred income tax assets	$ 251.3	$ 116.9	$ 166.9	$ 96.9
Gross deferred income tax liabilities	(834.3)	(746.0)	(826.8)	(721.4)
Net deferred income tax liability	$ (583.0)	$ (629.1)	$ (659.9)	$ (624.5)

Tax Credit Carryforwards

At December 31, 2006, the Company had $15.0 million of state income tax credit carryforwards. These credits relate primarily to the Company's Missouri affordable housing investment portfolio, and the carryforwards expire in years 2008 to 2011. 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 Holdings, Inc. and its subsidiaries,

Digital Teleport, Inc. and Digital Teleport of Virginia, Inc. 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 $0.5 million deferred state income tax benefit.

Uncertain Tax Positions

At December 31, 2006 and 2005, the Company had $4.7 million and $4.6 million, respectively, of liabilities for uncertain tax positions related to tax deductions or income positions taken on the Company's tax returns. Consolidated KCP&L had liabilities for uncertain tax positions of $1.8 million and $1.2 million at December 31, 2006 and 2005, 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 companies will reverse these tax provisions to net income. If the positions are not ultimately sustained, the companies may be required to make cash payments plus interest and/or utilize the companies' federal and state credit carryforwards.

In 2006, the FASB issued FASB Interpretation (FIN) No. 48, "Accounting for Uncertainty in Income Taxes," an interpretation of SFAS No. 109, "Accounting for Income Taxes." FIN No. 48 establishes a "more-likely-than-not" recognition threshold that must be met before a tax benefit can be recognized in the financial statements and requires various disclosures such as the policy surrounding classification of interest and penalties, a reconciliation of unrecognized tax benefit activity and disclosure of significant changes expected in unrecognized benefits within twelve months of the reporting date. Great Plains Energy and consolidated KCP&L are required to adopt the provisions of FIN No. 48 for periods beginning in 2007, although earlier adoption is permitted. The impact to the financial statements of Great Plains Energy and consolidated KCP&L upon adoption of FIN No. 48 is expected to be insignificant. In addition, Great Plains Energy and consolidated KCP&L will elect to recognize interest accrued related to unrecognized tax benefits in interest expense and penalties in operating expenses with the adoption of FIN No. 48.

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. 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 uncertain tax positions or had offsetting impacts on deferred taxes.

11. KLT GAS DISCONTINUED OPERATIONS

The KLT Gas natural gas properties (KLT Gas portfolio) was reported as discontinued operations in accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" after the 2004 Board of Directors approval to sell the KLT Gas portfolio and discontinue the gas business. During 2004 and 2005, KLT Gas completed sales of the KLT Gas portfolio and in 2006 KLT Gas had no

active operations. At December 31, 2005, KLT Gas had $0.6 million of current assets and $0.1 million of current liabilities recorded in assets and liabilities of discontinued operations. The following table summarizes the discontinued operations.

	2005	2004
	(millions)	
Revenues	$ -	$ 1.6
Loss from operations, including impairments, before income taxes	(2.9)	(4.5)
Gain on sales of assets	-	16.8
Discontinued operations before income taxes	(2.9)	12.3
Income taxes	1.0	(5.0)
Discontinued operations, net of income taxes	$ (1.9)	$ 7.3

12. RELATED PARTY TRANSACTIONS AND RELATIONSHIPS

Consolidated KCP&L receives 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 $18.5 million, $42.6 million and $62.7 million for 2006, 2005 and 2004, respectively. These costs consisted primarily of employee compensation, benefits and fees associated with various professional services. At December 31, 2006 and 2005, consolidated KCP&L had a short-term intercompany payable to Services of $2.5 million and $3.5 million, respectively. In 2005, approximately 80% of Services' employees were transferred to KCP&L to better align resources with the operating business. Also at December 31, 2006, consolidated KCP&L had a long-term intercompany payable to Services of $5.7 million related to unrecognized pension expense recorded under the provision of SFAS No. 158. At December 31, 2006 and 2005, consolidated KCP&L's balance sheets reflect a note payable from HSS to Great Plains Energy of $0.5 million.

13. COMMITMENTS AND CONTINGENCIES

Environmental Matters

The Company is subject to regulation by federal, state and local authorities with regard to air quality 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 seeks to use current technology to avoid and treat contamination. KCP&L conducts environmental audits designed to ensure compliance with governmental regulations. At December 31, 2006 and 2005, KCP&L had $0.3 million accrued for environmental remediation expenses. The 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.

Environmental-related legislation is continually introduced in Congress. Such legislation typically includes various compliance dates and compliance limits. Such legislation could have the potential for a significant financial impact on KCP&L, including the cost to install new pollution control equipment to achieve compliance. KCP&L would seek recovery of capital costs and expenses for such compliance

through rate increases; however, there can be no assurance that such rate increases would be granted. KCP&L will continue to monitor proposed legislation.

The change in political control of both chambers in Congress raises the possibility that legislation will be enacted to address global climate change and impose a national mandate to produce a set percentage of electricity from renewable forms of energy, such as wind. The probability and impact of such language is difficult to quantify at this time.

The following table contains current estimates of expenditures to comply with environmental laws and regulations described below. The ultimate cost of these regulations could be significantly different from the amounts estimated. The range of estimated expenditures increased significantly in 2006 primarily due to the demand for environmental projects increasing substantially with many utilities in the United States starting similar projects to address changing environmental regulations. This demand has constrained labor and material resources resulting in a significant escalation in the cost and completion times for environmental retrofits. KCP&L continues to refine its cost estimates detailed in the table below and explore alternatives. The allocation between states is based on location of the facilities and has no bearing as to recovery in jurisdictional rates.

Clean Air Estimated Required Environmental Expenditures	Missouri	Kansas	Total	Estimated Timetable
		(millions)		
CAIR	$375 - 993	$ -	$375 - 993	2006 - 2015
Incremental BART	-	272 - 527	272 - 527	2006 - 2017
Incremental CAMR	11 - 15	5 - 6	16 - 21	2010 - 2018
Estimated required environmental expenditures	$386 - 1,008	$277 - 533	$663 - 1,541	

Comprehensive Energy Plan Retrofits	Missouri	Kansas	Total
		(millions)	
Total estimated environmental expenditures	$255 - 264	$168 - 179	$423 - 443
Less: expenditures through December 31, 2006	25	31	56
Remaining balance	$230 - 239	$137 - 148	$367 - 387

Expenditure estimates provided in the first table above include, but are not limited to, the accelerated environmental upgrade expenditures included in KCP&L's comprehensive energy plan. These expenditures are expected to reduce SO_2, NO_x, mercury and air particulate matter emissions.

Clean Air Interstate Rule

The Environmental Protection Agency (EPA) Clean Air Interstate Rule (CAIR) requires reductions in SO_2 and NO_x emissions in 28 states, including Missouri. The reduction in both SO_2 and NO_x emissions will be accomplished through establishment of permanent statewide caps for NO_x effective January 1, 2009, and SO_2 effective January 1, 2010. More restrictive caps will be effective January 1, 2015. KCP&L's fossil fuel-fired plants located in Missouri are subject to CAIR, while its fossil fuel-fired plants in Kansas are not.

KCP&L expects to meet the emissions reductions required by CAIR at its Missouri plants through a combination of pollution control capital projects and the purchase of emission allowances in the open market as needed. The final CAIR rule establishes a market-based cap-and-trade program. Missouri has developed a State Implementation Plan (SIP) rule, which includes an emission allowance allocation mechanism, and has published, held a hearing, received comments and approved the proposed rule. Facilities will demonstrate compliance with CAIR by holding sufficient allowances for each ton of SO_2 and NO_x emitted in any given year with SO_2 emission allowances transferable among all regulated

facilities nationwide and NO_x emission allowances transferable among all regulated facilities within the 28 CAIR states. KCP&L will also be allowed to utilize unused SO_2 emission allowances that it has accumulated during previous years of the Acid Rain Program to meet the more stringent CAIR requirements. At December 31, 2006, KCP&L had accumulated unused SO_2 emission allowances sufficient to support just under 120,000 tons of SO_2 emission under the provisions of the Acid Rain program, which are recorded in inventory at zero cost. KCP&L is permitted to sell excess SO_2 emission allowances in accordance with KCP&L's comprehensive energy plan as approved by the MPSC and KCC.

Analysis of the final CAIR rule indicates that selective catalytic reduction technology for NO_x control and scrubbers for SO_2 control will likely be required for KCP&L's Montrose Station in Missouri, in addition to the environmental upgrades at Iatan No. 1 included in the comprehensive energy plan. The timing of the installation of such control equipment is currently being developed. As discussed below, certain of the control technology for SO_2 and NO_x will also aid in the control of mercury.

Best Available Retrofit Technology Rule

The EPA best available retrofit technology rule (BART) directs state air quality agencies to identify whether visibility-reducing emissions from sources subject to BART are below limits set by the state or whether retrofit measures are needed to reduce emissions. BART applies to specific eligible facilities including LaCygne Nos. 1 and 2 in Kansas and Iatan No. 1 and Montrose No. 3 in Missouri. The CAIR suggests that states that meet the CAIR requirements may also meet BART requirements for individual sources. Missouri has included this understanding as part of the proposed CAIR SIP. Kansas is not a CAIR state and therefore BART will impact LaCygne Nos. 1 and 2. KCP&L is in discussions with the Kansas Department of Health and Environment and anticipates submitting a BART analysis for LaCygne Station in early 2007. Kansas is in the process of reviewing BART analysis and modeling completed by the utilities with impacted facilities in the state. States must submit a BART implementation plan in 2007 with required emission controls. The BART emission control equipment must be compliant within five years after the SIP is approved by the EPA. If emission controls to comply with BART are required at LaCygne Nos. 1 and 2, additional capital expenditures will be required above comprehensive energy plan upgrades.

Mercury Emissions

The EPA Clean Air Mercury Rule (CAMR) regulates mercury emissions from coal-fired power plants located in 48 states, including Kansas and Missouri, under the New Source Performance Standards of the Clean Air Act. The rule established a market-based cap-and-trade program that will reduce nationwide utility emissions of mercury in two phases. The first phase cap is effective January 1, 2010, and will establish a permanent nationwide cap of 38 tons of mercury for coal-fired power plants. Management anticipates meeting the first phase cap by taking advantage of KCP&L's mercury reductions achieved through capital expenditures to comply with CAIR and BART. The second phase is effective January 1, 2018, and will establish a permanent nationwide cap of 15 tons of mercury for coal-fired power plants. When fully implemented, the rule will reduce utility emissions of mercury by nearly 70% from current emissions of 48 tons per year. In Missouri, the CAMR SIP is following the same process and schedule as the CAIR SIP previously described above. In Kansas, the CAMR SIP has been published for public review and comment, and a hearing is scheduled.

Facilities will demonstrate compliance with the standard by holding allowances for each ounce of mercury emitted in any given year and allowances will be readily transferable among all regulated facilities nationwide. Under the cap-and-trade program, KCP&L will be able to purchase mercury allowances or elect to install pollution control equipment to achieve compliance. While it is expected that mercury allowances will 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. Management expects capital expenditures will be required

to install additional pollution control equipment to meet the second phase cap. During the ensuing years, management will closely monitor advances in technology for removal of mercury from Powder River Basin (PRB) coal and expects to make decisions regarding second phase removal based on then available technology to meet the 2018 compliance date. KCP&L participated in the DOE National Energy Technology Laboratory project to investigate control technology options for mercury removal from coal-fired plants burning sub-bituminous coal.

Carbon Dioxide

Many legislative bills concerning CO_2 are being debated in the U.S. Congress. 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 connection with achieving compliance with the proposed new nationwide limits. However, the financial consequences to KCP&L cannot be determined until final legislation is passed. Management will continue to monitor the progress of these bills.

KCP&L is a member of 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. Power Partners entered into a cooperative umbrella memorandum of understanding (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 (carbon intensity), consistent with the EEI's 2003 commitment of a 3% to 5% reduction over the next decade. Power Partners' January 2007 annual report indicates it is on track to reach that goal.

Ozone

The Missouri Department of Natural Resources and the Kansas Department of Health and Environment continue to develop Missouri and Kansas Maintenance Plans for the Control of Ozone for the Kansas City area. The EPA will require Missouri and Kansas to submit these SIPs by June 2007. As part of the SIP requirements, contingency control measures must be included. These measures would go into effect only if associated triggers (such as a violation of the eight-hour ozone standard) occur. Although it is anticipated the proposed controls for CAIR and BART will provide the contingency control measures at KCP&L generation facilities, management will continue to be involved and monitor the SIP development.

Water Use Regulations

The EPA Clean Water Act established standards for cooling water intake structures. This regulation applies to certain existing power producing facilities that employ cooling water intake structures that withdraw 50 million gallons or more per day from lakes and rivers and use 25% or more of that water for cooling purposes. The regulation is designed to protect aquatic life from being killed or injured by cooling water intake structures. KCP&L is required to complete a comprehensive demonstration study on each of its generating facilities' intake structures by the end of 2007. The studies are expected to cost a total of $1.2 million to $2.0 million. Depending on the outcome of the comprehensive demonstration studies, facilities may be required to implement technological or operational measures to achieve compliance. Compliance with this regulation is expected to be achieved between 2011 and 2014. Until the comprehensive demonstration studies are completed, the impact of this regulation cannot be quantified.

A recent Federal appeals court decision may ultimately impact this regulation. The court remanded much of the regulation to the EPA for further rulemaking. At this time, the EPA has not acted on the court's decision. Management will continue to monitor the litigation and any subsequent rulemaking associated with this regulation.

KCP&L holds a permit from the Missouri Department of Natural Resources covering water discharge from its Hawthorn Station. The permit authorizes KCP&L, among other things, to withdraw water from the Missouri river for cooling purposes and return the heated water to the Missouri river. KCP&L has applied for a renewal of this permit and the EPA has submitted an interim objection letter regarding the allowable amount of heat that can be contained in the returned water. Until this matter is resolved, KCP&L continues to operate under its current permit. KCP&L cannot predict the outcome of this matter; however, while less significant outcomes are possible, this matter may require KCP&L to reduce its generation at Hawthorn Station, install cooling towers or both, any of which could adversely affect KCP&L. The outcome could also affect the terms of water permit renewals at KCP&L's Iatan and Montrose Stations.

Contractual Commitments

Great Plains Energy's and consolidated KCP&L's expenses related to lease commitments are detailed in the following table.

	2006	2005	2004
		(millions)	
Consolidated KCP&L	$ 17.6	$ 19.4	$ 18.4
Other Great Plains Energy [(a)]	1.3	1.4	1.9
Total Great Plains Energy	$ 18.9	$ 20.8	$ 20.3

[(a)] Includes insignificant amounts related to discontinued operations.

Great Plains Energy's and consolidated KCP&L's contractual commitments at December 31, 2006, excluding pensions and long-term debt are detailed in the following tables.

Great Plains Energy Contractual Commitments

	2007	2008	2009	2010	2011	After 2011	Total
				(millions)			
Lease commitments	$ 16.7	$ 16.4	$ 11.9	$ 9.0	8.1	$ 82.3	$ 144.4
Purchase commitments							
Fuel [(a)]	130.9	121.4	65.7	65.7	11.4	185.3	580.4
Purchased capacity	6.8	7.8	8.2	5.4	4.3	14.3	46.8
Purchased power	741.8	330.5	223.2	165.2	82.1	13.3	1,556.1
Comprehensive energy plan	498.8	361.0	130.1	15.2	-	-	1,005.1
Other	36.3	22.6	4.7	10.5	3.9	22.5	100.5
Total contractual commitments	$ 1,431.3	$ 859.7	$ 443.8	$ 271.0	$ 109.8	$ 317.7	$ 3,433.3

[(a)] Fuel commitments consists of commitments for nuclear fuel, coal, coal transportation costs and natural gas.

Consolidated KCP&L Contractual Commitments

	2007	2008	2009	2010	2011	After 2011	Total
				(millions)			
Lease commitments	$ 15.5	$ 15.4	$ 11.7	$ 9.0	$ 8.1	$ 82.3	$ 142.0
Purchase commitments							
Fuel [(a)]	130.9	121.4	65.7	65.7	11.4	185.3	580.4
Purchased capacity	6.8	7.8	8.2	5.4	4.3	14.3	46.8
Comprehensive energy plan	498.8	361.0	130.1	15.2	-	-	1,005.1
Other	36.3	22.6	4.7	10.5	3.9	22.5	100.5
Total contractual commitments	$ 688.3	$ 528.2	$ 220.4	$ 105.8	$ 27.7	$ 304.4	$ 1,874.8

[(a)] Fuel commitments consists of commitments for nuclear fuel, coal, coal transportation costs and natural gas.

Lease commitments end in 2028 and include insignificant amounts for capital leases. As the managing partner of three jointly owned generating units, KCP&L has entered into leases for railcars to serve those units. The entire lease commitment is reflected in the above amounts, although the other owners will reimburse KCP&L approximately $2.0 million per year ($21.4 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 $11.2 million per year for 2007 through 2010, $6.9 million in 2011 and $3.8 million after 2011.

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 2007 totaling $172.4 million.

Comprehensive energy plan represents KCP&L's contractual commitment for projects included in its comprehensive energy plan. KCP&L expects to be reimbursed by other owners for their respective share of Iatan No. 2 and environmental retrofit costs included in the comprehensive energy plan contractual commitments. See Note 6 for estimated capital expenditures by major project. Other represents individual commitments entered into in the ordinary course of business.

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. Great Plains Energy has provided $258.7 million of guarantees to support certain Strategic Energy power purchases and regulatory requirements. At December 31, 2006, guarantees related to Strategic Energy are as follows:

- Great Plains Energy direct guarantees to counterparties totaling $142.0 million, which expire in 2007,
- Great Plains Energy indemnifications to surety bond issuers totaling $0.5 million, which expire in 2007,
- Great Plains Energy guarantee of Strategic Energy's revolving credit facility totaling $12.5 million, which expires in 2009 and
- Great Plains Energy letters of credit totaling $103.7 million, which expire in 2007.

At December 31, 2006, KCP&L had guaranteed, with a maximum potential of $2.9 million, energy savings under an agreement with a customer that expires over the next three years. A subcontractor would indemnify KCP&L for any payments made by KCP&L under this guarantee. This guarantee was 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

Union Pacific

In 2005, KCP&L filed a rate complaint case with the STB charging that Union Pacific Railroad Company's (Union Pacific) rates for transporting coal from the PRB in Wyoming to KCP&L's Montrose

Station are unreasonably high. Prior to the end of 2005, the rates were established under a contract with Union Pacific. Efforts to extend the term of the contract were unsuccessful and Union Pacific is the only service for coal transportation from the PRB to Montrose Station. KCP&L charged that Union Pacific possesses market dominance over the traffic and requested the STB prescribe maximum reasonable rates. In February 2006, the STB instituted a rulemaking to address issues regarding the cost test used in rail rate cases and the proper calculation of rail rate relief. As part of that order, the STB delayed hearing KCP&L's case pending the outcome of the rulemaking, and declared that the results of the rulemaking would apply to KCP&L's test. In October 2006, the STB issued its decision, adopting the proposal set out in its rulemaking. This decision has been appealed by other parties to the Federal Circuit Court of Appeals for the District of Columbia. In July 2006, the STB directed KCP&L and Union Pacific to file comments in September 2006 on whether KCP&L's complaint is within the STB's jurisdiction. If the STB determines it does have jurisdiction, it will issue a new procedural schedule. Management currently expects a decision in the case in 2008. Until the STB case is decided, KCP&L is paying the higher tariff rates subject to refund.

Framatome

In 2005, WCNOC filed a lawsuit on behalf of itself, KCP&L and the other two Wolf Creek owners against Framatome ANP, Inc., and Framatome ANP Richland, Inc. (Framatome) in the District Court of Coffey County, Kansas. The suit alleged various claims against Framatome related to the proposed design, licensing and installation of a digital control system. The suit sought recovery of approximately $16 million in damages from Framatome. Framatome filed a counterclaim against the three Wolf Creek owners seeking recovery of damages alleged to be in excess of $20 million. In May 2006, the parties settled this case. The settlement had no significant impact on KCP&L's results of operations or financial position.

Hawthorn No. 5 Subrogation Litigation

KCP&L filed suit in 2001, in Jackson County, Missouri Circuit Court against multiple defendants who are alleged to have responsibility for the 1999 Hawthorn No. 5 boiler explosion. KCP&L and National Union Fire Insurance Company of Pittsburgh, Pennsylvania (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. Prior to 2006, certain defendants were dismissed from the suit and various defendants settled, with KCP&L receiving a total of $38.2 million, of which $18.5 million was recorded as a recovery of capital expenditures. 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. In May 2004, the trial judge reduced the award against the defendant to $0.2 million. Both KCP&L and the defendant appealed this case to the Court of Appeals for the Western District of Missouri, and in May 2006, the Court of Appeals ordered the Circuit Court to enter judgment in KCP&L's favor in accordance with the jury verdict. The defendant filed a motion for transfer of this case to the Missouri Supreme Court, which was denied. 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), KCP&L received proceeds of $38.9 million in 2006 pursuant to the subrogation allocation agreement after payment of attorney's fees. The proceeds reduced purchased power expense by $10.8 million and fuel expense by $3.7 million. The proceeds also increased wholesale revenues by $2.5 million and included $6.1 million of interest that increased non-operating income. The remaining $15.8 million of proceeds were recorded as a recovery of capital expenditures.

KCP&L previously received reimbursement for Hawthorn No. 5 damages under a property damage insurance policy with Travelers Property Casualty Company of America (Travelers). Travelers filed suit in the U.S. District Court for the Eastern District of Missouri in November 2005, against National Union, and KCP&L was added as a defendant in June 2006. The case was subsequently transferred to, and is pending in, the U.S. District Court for the Western District of Missouri. Travelers seeks recovery of

$10 million that KCP&L recovered in the April 2001 lawsuit described in the preceding paragraph. Management is unable to predict the outcome of this litigation.

Emergis Technologies, Inc.
In March 2006, Emergis Technologies, Inc. f/k/a BCE Emergis Technologies, Inc. (Emergis) filed suit against KCP&L in Federal District Court for the Western District of Missouri, alleging infringement of a patent, entitled "Electronic Invoicing and Payment System." This patent relates to automated electronic bill presentment and payment systems, particularly those involving Internet billing and collection. In March 2006, KCP&L filed a response and denied infringing the patent. KCP&L counterclaimed for a declaration that the patent is invalid and not infringed. Emergis responded to KCP&L's counterclaims in April 2006. Court ordered mediation occurred in July 2006, but the case was not resolved. Management does not expect the outcome of this litigation to have a significant impact on Great Plains Energy's or consolidated KCP&L's results of operations and financial position.

Spent Nuclear Fuel and Radioactive Waste
In 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. Approximately sixty other similar cases are pending before that court. A handful of the cases have received damages awards, most of which are on appeal now. The Wolf Creek case is on a court-ordered stay until further order of the court to allow for some of the earlier cases to be decided first by an appellate court. 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 management cannot predict the outcome of this Wolf Creek case.

Class Action Complaint
In 2005, a class action complaint for breach of contract was filed against Strategic Energy in the Court of Common Pleas of Allegheny County, Pennsylvania. The plaintiffs purportedly represent the interests of certain customers in Pennsylvania who entered into Power Supply Coordination Service Agreements (Agreements) for a certain product in Pennsylvania. The complaint seeks monetary damages, attorney fees and costs and a declaration that the customers may terminate their Agreements with Strategic Energy. In response to Strategic Energy's preliminary objections, plaintiffs have filed an amended complaint that management is evaluating. The plaintiffs have granted Strategic Energy an indefinite extension of time to answer the complaint. Management is unable to predict the outcome of this litigation.

Texas Customer Dispute
In February 2006, a customer in Texas that procures electricity for schools notified Strategic Energy that it had selected another provider for its school members during the time it was under contract with Strategic Energy. Strategic Energy exercised it rights under the agreement for breach. In June 2006, Strategic Energy received a notice of demand for arbitration from the customer pursuant to the agreement. Management is evaluating the merits of the customer's alleged damages and the parties have begun settlement discussions. Management believes the ultimate outcome of this matter will not have a significant impact on the Company's financial position or results of operations.

Haberstroh
In 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, L.L.C. (SE Holdings) and Strategic Energy in the Court of Common Pleas of Allegheny

County, Pennsylvania. In 2006, the suit was settled and as part of the settlement, Great Plains Energy acquired the remaining indirect interest in Strategic Energy for an insignificant amount.

Weinstein v. KLT Telecom

Richard D. Weinstein (Weinstein) filed suit against KLT Telecom Inc. (KLT Telecom) in September 2003 in the St. Louis County, Missouri Circuit Court. KLT Telecom acquired a controlling interest in DTI Holdings, Inc. (Holdings) in February 2001 through the purchase of approximately two-thirds of the Holdings stock held by Weinstein. In connection with that purchase, KLT Telecom entered into a put option in favor of Weinstein, which granted Weinstein an option to sell to KLT Telecom his remaining shares of Holdings stock. The put option provided for an aggregate exercise price for the remaining shares equal to their fair market value with an aggregate floor amount of $15 million and was exercisable between September 1, 2003, and August 31, 2005. In June 2003, the stock of Holdings was cancelled and extinguished pursuant to the joint Chapter 11 plan confirmed by the Bankruptcy Court. In September 2003, Weinstein delivered a notice of exercise of his claimed rights under the put option. KLT Telecom rejected the notice of exercise, and Weinstein filed suit, alleging breach of contract. Weinstein sought damages of at least $15 million, plus statutory interest. In April 2005, summary judgment was granted in favor of KLT Telecom, and Weinstein appealed this judgment to the Missouri Court of Appeals for the Eastern District. In May 2006, the Court of Appeals affirmed the judgment. In July 2006, Weinstein filed an application for transfer of this case to the Missouri Supreme Court, which was granted. Oral arguments were presented to the Supreme Court in December 2006. The $15 million reserve has not been reversed pending the outcome of the appeal process.

16. ASSET RETIREMENT OBLIGATIONS

Asset retirement obligations associated with tangible long-lived assets 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. These liabilities are recognized at estimated fair value as incurred and capitalized as part of the cost of the related long-lived assets and depreciated over their useful lives. Accretion of the liabilities due to the passage of time is recorded as an operating expense. Changes in the estimated fair values of the liabilities are recognized when known.

In 2006, KCP&L incurred an ARO for decommissioning and site remediation of its Spearville Wind Energy Facility, a 100.5 MW wind project in western Kansas. KCP&L is obligated to remove the wind turbine towers and perform site remediation within 12 months after the end of the associated 30-year land lease agreements. The ARO was derived from a third party estimate of decommissioning and remediation costs. To estimate the ARO, KCP&L used a credit-adjusted risk free discount rate of 6.68%. This rate was based on the rate at which KCP&L could issue 30-year bonds. KCP&L recorded a $3.1 million ARO for the decommissioning and site remediation and increased property and equipment by $3.1 million.

In 2006, WCNOC submitted an application for a new operating license for Wolf Creek with the NRC, which would extend Wolf Creek's operating period to 2045. Management has determined the fair value of KCP&L's ARO for nuclear decommissioning should reflect the change in timing in the undiscounted estimated cash flows to decommission Wolf Creek as a result of the extended operating period. Management calculated an ARO revision based on KCP&L's most recent cost estimates to decommission Wolf Creek. To estimate the ARO layer attributable to the change in timing, KCP&L used a credit-adjusted risk free discount rate of 6.26%. The rate was based on the rate at which KCP&L could issue 40-year bonds. KCP&L recorded a $65.0 million decrease in the ARO to decommission Wolf Creek with a $25.8 million net decrease in property and equipment. The regulatory asset for ARO decreased $8.2 million and a $31.0 million regulatory liability was established to recognize funding of the related decommissioning trust in excess of the ARO due to the extended operating period.

In 2005, FASB issued FIN No. 47, "Accounting for Conditional Asset Retirement Obligations." FIN No. 47 clarifies the term conditional ARO, as used in SFAS No. 143, "Accounting for Asset Retirement Obligations." Conditional ARO refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Under FIN No. 47, an entity is required to recognize a liability for the fair value of a conditional ARO if the fair value of the liability can be reasonably estimated. Great Plains Energy and consolidated KCP&L adopted the provisions of FIN No. 47 in 2005.

KCP&L management determined AROs exist for asbestos in certain fossil fuel plants and for an ash pond and landfill. The additional AROs recorded in 2005 totaled $8.4 million for remediation of asbestos and $7.0 million for the remediation of the ash pond and landfill. In recording these AROs, net utility plant was increased $2.2 million and the $13.2 million net effect of adopting FIN No. 47 was recorded as a regulatory asset and had no impact on net income. The AROs were derived from third party and internal engineering estimates. To estimate the AROs, KCP&L used a credit-adjusted risk free discount rate of 5.6% for 12.5-year assets, 5.89% for 19.5-year asset and 6.12% for 29.5-year assets. The estimated rate was based on the rate KCP&L could issue bonds for the specific period.

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 FIN No. 47 or SFAS No. 143 and expense recovered currently in rates will be recoverable in future rates. The following table summarizes the change in Great Plains Energy's and consolidated KCP&L's AROs.

December 31	2006	2005
	(millions)	
Beginning balance	$ 145.9	$ 113.7
Additions	3.1	26.7
Extension of Wolf Creek life	(65.0)	-
Settlements	-	(2.0)
Accretion	7.8	7.5
Ending balance	$ 91.8	$ 145.9

17. SEGMENTS 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, and Strategic Energy, a competitive electricity supplier. Other includes HSS, Services, all KLT Inc. activity other than Strategic Energy, unallocated corporate charges, consolidating entries 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 following tables reflect summarized financial information concerning Great Plains Energy's reportable segments.

2006	KCP&L	Strategic Energy	Other	Great Plains Energy
		(millions)		
Operating revenues	$1,140.4	$ 1,534.9	$ -	$ 2,675.3
Depreciation and amortization	(152.7)	(7.8)	-	(160.5)
Interest charges	(60.9)	(2.1)	(8.2)	(71.2)
Income taxes	(71.6)	12.7	11.0	(47.9)
Loss from equity investments	-	-	(1.9)	(1.9)
Net income (loss)	149.6	(9.9)	(12.1)	127.6

As Adjusted 2005	KCP&L	Strategic Energy	Other	Great Plains Energy
		(millions)		
Operating revenues	$1,130.8	$ 1,474.0	$ 0.1	$ 2,604.9
Depreciation and amortization	(146.5)	(6.4)	(0.2)	(153.1)
Interest charges	(61.8)	(3.4)	(8.6)	(73.8)
Income taxes	(49.1)	(16.6)	26.2	(39.5)
Loss from equity investments	-	-	(0.4)	(0.4)
Discontinued operations	-	-	(1.9)	(1.9)
Net income (loss)	145.2	28.2	(11.1)	162.3

As Adjusted 2004	KCP&L	Strategic Energy	Other	Great Plains Energy
		(millions)		
Operating revenues	$1,090.1	$ 1,372.4	$ 1.5	$ 2,464.0
Depreciation and amortization	(144.3)	(4.8)	(1.0)	(150.1)
Interest charges	(73.7)	(0.7)	(8.6)	(83.0)
Income taxes	(56.7)	(24.3)	25.5	(55.5)
Loss from equity investments	-	-	(1.5)	(1.5)
Discontinued operations	-	-	7.3	7.3
Net income (loss)	151.7	42.5	(11.7)	182.5

	KCP&L	Strategic Energy	Other	Great Plains Energy
2006		(millions)		
Assets	$ 3,858.0	$ 459.6	$ 18.1	$ 4,335.7
Capital expenditures	476.0	3.9	0.2	480.1
As Adjusted 2005				
Assets	$ 3,336.3	$ 441.8	$ 63.7	$ 3,841.8
Capital expenditures	332.2	6.6	(4.7)	334.1
As Adjusted 2004				
Assets	$ 3,327.7	$ 407.7	$ 61.0	$ 3,796.4
Capital expenditures	190.8	2.6	3.3	196.7

Consolidated KCP&L

The following tables reflect summarized financial information concerning consolidated KCP&L's reportable segment. Other includes HSS and intercompany eliminations. Intercompany eliminations include insignificant amounts of intercompany financing-related activities.

2006	KCP&L	Other	Consolidated KCP&L
		(millions)	
Operating revenues	$ 1,140.4	$ -	$ 1,140.4
Depreciation and amortization	(152.7)	-	(152.7)
Interest charges	(60.9)	(0.1)	(61.0)
Income taxes	(71.6)	1.3	(70.3)
Net income (loss)	149.6	(0.3)	149.3

As Adjusted 2005	KCP&L	Other	Consolidated KCP&L
		(millions)	
Operating revenues	$ 1,130.8	$ 0.1	$ 1,130.9
Depreciation and amortization	(146.5)	(0.1)	(146.6)
Interest charges	(61.8)	-	(61.8)
Income taxes	(49.1)	1.1	(48.0)
Net income (loss)	145.2	(1.5)	143.7

As Adjusted 2004	KCP&L	Other	Consolidated KCP&L
		(millions)	
Operating revenues	$ 1,090.1	$ 1.5	$ 1,091.6
Depreciation and amortization	(144.3)	(0.9)	(145.2)
Interest charges	(73.7)	(0.5)	(74.2)
Income taxes	(56.7)	2.9	(53.8)
Net income (loss)	151.7	(6.7)	145.0

	KCP&L	Other	Consolidated KCP&L
2006		(millions)	
Assets	$ 3,858.0	$ 1.5	$ 3,859.5
Capital expenditures	476.0	-	476.0
As Adjusted 2005			
Assets	$ 3,336.3	$ 3.9	$ 3,340.2
Capital expenditures	332.2	-	332.2
As Adjusted 2004			
Assets	$ 3,327.7	$ 7.2	$ 3,334.9
Capital expenditures	190.8	-	190.8

18. SHORT-TERM BORROWINGS AND SHORT-TERM BANK LINES OF CREDIT

During 2006, Great Plains Energy entered into a five-year $600 million revolving credit facility with a group of banks. The facility replaced a $550 million revolving credit facility with a group of banks. A default by Great Plains Energy or any of its significant subsidiaries on other indebtedness totaling more than $25.0 million is a default under the 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, 2006, the Company was in compliance with this covenant. At December 31, 2006, Great Plains Energy had no cash borrowings and had issued letters of credit totaling $103.7 million under the credit facility as credit support for Strategic Energy. At December 31, 2005, Great Plains Energy had $6.0 million of outstanding borrowings with an interest rate of 4.98% and had issued letters of credit totaling $38.5 million under the credit facility as credit support for Strategic Energy.

During 2006, KCP&L entered into a five-year $400 million revolving credit facility with a group of banks to provide support for its issuance of commercial paper and other general corporate purposes. Great Plains Energy and KCP&L may transfer and re-transfer up to $200 million of unused lender commitments between Great Plains Energy's and KCP&L's facilities, so long as the aggregate lender commitments under either facility does not exceed $600 million and the aggregate lender commitments under both facilities does not exceed $1 billion. The facility replaced a $250 million revolving credit facility with a group of banks. A default by KCP&L on other indebtedness totaling more than $25.0 million is a default under the 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, 2006, KCP&L was in compliance with this covenant. At December 31, 2006, KCP&L had $156.4 million of commercial paper outstanding, at a weighted-average interest rate of 5.38%, issued $8.7 million of letters of credit and had no cash borrowings under the facility. At December 31, 2005, KCP&L had $31.9 million of commercial paper outstanding, at a weighted-average interest rate of 4.35% and no cash borrowings under the facility.

Strategic Energy has a $135 million revolving credit facility with a group of banks that expires in June 2009. As long as Strategic Energy is in compliance with the agreement, it may increase this amount by up to $15 million by increasing the commitment of one or more lenders that have agreed to such increase, or by adding one or more lenders with the consent of the administrative agent. In October 2006, Great Plains Energy, as permitted by the terms of the agreement, requested and received a reduction in its guarantee of this facility from $25.0 million to $12.5 million. Under this facility, Strategic Energy's maximum it may loan to Great Plains Energy is $20 million. A default by Strategic Energy on 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 $75.0 million, 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 addition, under the terms of this agreement, Strategic Energy is required to maintain a maximum funded indebtedness to EBITDA ratio, as defined in the agreement, of 3.00 to 1.00, on a quarterly basis through June 30, 2007, and 2.75 to 1.00 thereafter. 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, 2006, Strategic Energy was in compliance with these covenants. At December 31, 2006, $59.8 million in letters of credit had been issued and there were no cash borrowings under the agreement. At December 31, 2005, $75.2 million in letters of credit had been issued and there were no cash borrowings under the agreement.

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.

	Year Due	December 31 2006	2005
		(millions)	
Consolidated KCP&L			
General Mortgage Bonds			
7.95% Medium-Term Notes	2007	$ 0.5	$ 0.5
3.84%* EIRR bonds	2012-2035	158.8	158.8
Senior Notes			
6.00%	2007	225.0	225.0
6.50%	2011	150.0	150.0
6.05%	2035	250.0	250.0
Unamortized discount		(1.6)	(1.8)
EIRR bonds			
4.75% Series A & B	2015	105.2	104.6
4.75% Series D	2017	39.5	39.3
4.65% Series 2005	2035	50.0	50.0
Current liabilities			
Current maturities		(225.5)	-
EIRR bonds classified as current		(144.7)	-
Total consolidated KCP&L excluding current maturities		607.2	976.4
Other Great Plains Energy			
7.74% Affordable Housing Notes	2007-2008	0.9	2.6
4.25% FELINE PRIDES Senior Notes	2007	163.6	163.6
Current maturities		(164.2)	(1.7)
Total consolidated Great Plains Energy excluding current maturities		$ 607.5	$ 1,140.9

* Weighted-average interest rates at December 31, 2006.

Amortization of Debt Expense

Great Plains Energy's and consolidated KCP&L's amortization of debt expense is detailed in the following table.

	2006	2005	2004
		(millions)	
Consolidated KCP&L	$ 1.9	$ 2.3	$ 2.1
Other Great Plains Energy	0.7	0.7	1.8
Total Great Plains Energy	$ 2.6	$ 3.0	$ 3.9

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 of medium-term notes and Environmental Improvement Revenue Refunding (EIRR) bonds at December 31, 2006 and 2005.

In 2005, KCP&L redeemed its secured 1994 series EIRR bonds totaling $35.9 million by issuing secured EIRR Bonds Series 2005 also totaling $35.9 million: $14.0 million at a fixed rate of 4.05% until maturity at March 1, 2015, and $21.9 million at a fixed rate of 4.65% until maturity at September 1, 2035. The EIRR Bonds Series 2005 is covered by a municipal bond insurance policy issued by XL Capital Assurance Inc. (XLCA). The insurance agreement between KCP&L and XLCA is described below.

KCP&L Unsecured Notes
KCP&L had $625.0 million of outstanding unsecured senior notes at December 31, 2006 and 2005. As a result of amortizing the gain recognized in other comprehensive income (OCI) on KCP&L's 2005 Treasury Locks (T-Locks), the effective interest rate on KCP&L's $250.0 million of 6.05% Senior Notes that were issued via a private placement during 2005 is 5.78%. In 2006, KCP&L completed an exchange of these privately placed notes for $250.0 million of registered 6.05% unsecured senior notes maturing in 2035 to fulfill its obligations under a 2005 registration rights agreement.

KCP&L had $196.5 million of unsecured EIRR bonds outstanding excluding the fair value of interest rate swaps of a $1.8 million and a $2.6 million liability in 2006 and 2005, respectively. The interest rates swaps resulted in an effective rate of 5.85% for the Series A, B and D EIRR bonds in 2006. During 2005, KCP&L redeemed its unsecured Series C EIRR bonds totaling $50.0 million by issuing unsecured EIRR Bonds Series 2005 also totaling $50.0 million at a fixed rate of 4.65% until maturity at September 1, 2035. The EIRR Bonds Series 2005 is covered by a municipal bond insurance policy issued by XLCA. The insurance agreement between KCP&L and XLCA is described below.

Forward Starting Swaps
During 2006, KCP&L entered into two Forward Starting Swaps (FSS) with a combined notional principal amount of $225.0 million to hedge interest rate volatility on the anticipated refinancing of KCP&L's $225.0 million senior notes that mature in March 2007. See Note 22 for additional information.

Municipal Bond Insurance Policies
The insurance agreements between KCP&L and XLCA provide for reimbursement by KCP&L for any amounts that XLCA pays under the municipal bond insurance policies. The insurance policies are in effect for the term of the bonds. The insurance agreements contain 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, 2006, 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. The insurance agreement covering the unsecured EIRR Bond Series 2005 also requires KCP&L to provide XLCA with $50.0 million of general mortgage bonds as collateral for KCP&L's obligations under the insurance agreement in the event KCP&L issues general mortgage bonds (other than refundings of outstanding general mortgage bonds) resulting in the aggregate amount of outstanding general mortgage bonds exceeding 10% of total capitalization. In the event of a default under the insurance agreements, XLCA may take any available legal or equitable action against KCP&L, including seeking specific performance of the covenants.

Other Great Plains Energy Long-Term Debt
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, 2006 and 2005, the collateral was held entirely as cash and totaled $0.6 million and $1.9 million, respectively.

In 2006, Great Plains Energy entered into a T-Lock with a notional principal amount of $77.6 million to hedge against interest rate fluctuation on future issuances of long-term debt. See Note 22 for additional information.

Great Plains Energy's $163.6 million of FELINE PRIDES each with a stated amount of $25, initially consisted 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. Great Plains Energy made 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. Each purchase contract obligated 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 was determined according to the applicable market value of the Company's common stock at the settlement date. The applicable market value of $31.58 was 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 of 0.7915 was applied to the 6.5 million FELINE PRIDES at February 16, 2007, and Great Plains Energy issued 5.2 million shares of common stock. The $163.6 million FELINE PRIDES senior notes originally matured in 2009, but were to be remarketed between August 16, 2006 and February 16, 2007. Great Plains Energy exercised its rights to redeem the $163.6 million FELINE PRIDES senior notes in full satisfaction of each holder's obligation to purchase the Company's common stock under the purchase contracts.

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.

	2007	2008	2009	2010	2011
			(millions)		
Consolidated KCP&L	$ 225.5	$ -	$ -	$ -	$ 150.0
Other Great Plains Energy	164.1	0.3	-	-	-
Total Great Plains Energy	$ 389.6	$ 0.3	$ -	$ -	$ 150.0

20. COMMON SHAREHOLDERS' EQUITY

Great Plains Energy filed a shelf registration statement with the Securities and Exchange Commission (SEC) in 2006 relating to Senior Debt Securities, Subordinated Debt Securities, shares of Common Stock, Warrants, Stock Purchase Contracts and Stock Purchase Units. In 2006, Great Plains Energy issued 5.2 million shares of common stock at $27.50 per share under the shelf registration statement with $144.3 million in gross proceeds and issuance costs of $5.2 million.

In 2006, Great Plains Energy also entered into a forward sale agreement with Merrill Lynch Financial Markets, Inc. (forward purchaser) for 1.8 million shares of Great Plains Energy common stock. The forward purchaser borrowed and sold the same number of shares of Great Plains Energy's common stock to hedge its obligations under the forward sale agreement. Great Plains Energy did not initially receive any proceeds from the sale of common stock shares by the forward purchaser. The forward sale agreement provides for a settlement date or dates to be specified at Great Plains Energy's discretion, subject to certain exceptions, no later than May 23, 2007. Subject to the provisions of the forward sale agreement, Great Plains Energy will receive an amount equal to $26.6062 per share, plus interest based on the federal funds rate less a spread and less certain scheduled decreases if Great Plains Energy elects to physically settle the forward sale agreement solely by delivering shares of common stock. In most circumstances, Great Plains Energy also has the right, in lieu of physical settlement, to elect cash or net physical settlement. Great Plains Energy currently expects to net cash settle the forward sale agreement.

Treasury shares are held for future distribution upon issuance of shares in conjunction with the Company's Long-Term Incentive Plan.

In 2006, Great Plains Energy registered an additional 1.0 million shares of common stock with the SEC for its Dividend Reinvestment and Direct Stock Purchase Plan, bringing the total number of shares registered under this plan to 4.0 million. 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, 2006, 1.0 million shares remained available for future issuances.

In 2006, Great Plains Energy registered an additional 1.0 million shares of common stock with the SEC for a defined contribution savings plan, bringing the total number of shares registered under this plan to 10.3 million. Shares issued under the plans may be either newly issued shares or shares purchased in the open market. At December 31, 2006, 1.2 million shares remained available for future issuances.

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. 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.

Great Plains Energy made capital contributions to KCP&L of $134.6 million in 2006. These contributions were made to fund comprehensive energy plan projects. At December 31, 2006, KCP&L's capital contributions from Great Plains Energy totaled $534.6 million and are reflected in common stock in the consolidated KCP&L balance sheet.

21. PREFERRED STOCK

At December 31, 2006, 1.6 million shares of Cumulative No Par Preferred Stock, 390,000 shares of Cumulative Preferred Stock, $100 par value and 11.0 million shares of no par Preference Stock were authorized under Great Plains Energy's Articles of Incorporation. All of the authorized shares of Cumulative Preferred Stock are issued and outstanding. Great Plains Energy has the option to redeem the $39.0 million of issued Cumulative Preferred Stock at prices approximating par or stated value.

22. DERIVATIVE INSTRUMENTS

The Company is exposed 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 the Company's operating results. The risk management activities, including the use of derivative instruments, are subject to the management, direction and control of internal risk management committees. Management'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. In addition, the Company uses derivative instruments to hedge against future interest rate fluctuations on anticipated debt issuances. Management maintains commodity-price risk management strategies that use derivative instruments to reduce the effects of fluctuations in fuel and purchased power expense caused by commodity price volatility. Counterparties to 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 less the application of counterparty collateral held. Derivative instruments, excluding those instruments that qualify for the NPNS election which are accounted for by accrual accounting, are recorded on the balance sheet at fair value 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 five-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.

Cash Flow Hedges - Forward Starting Swaps
In 2006, KCP&L entered into two FSS to hedge against interest rate fluctuations on future issuances of long-term debt. The FSS will be settled simultaneously with the issuance of the long-term fixed rate debt. The FSS effectively removes most of the interest rate and credit spread uncertainty with respect to the debt to be issued, thereby enabling KCP&L to predict with greater assurance what its future interest costs on that debt will be. The FSS is accounted for as a cash flow hedge and the fair value is recorded as a current asset or liability with an offsetting entry to OCI, to the extent the hedge is effective, until the forecasted transaction occurs. No ineffectiveness has been recorded on the FSS. The pre-tax gain or loss on the FSS recorded to OCI will be reclassified to interest expense over the life of the future debt issuance.

Cash Flow Hedges - Treasury Locks
In 2006, Great Plains Energy entered into a T-Lock to hedge against interest rate fluctuations on future issuances of long-term debt. The T-Lock will be settled simultaneously with the issuance of the long-term fixed rate debt. The T-Lock effectively removes most of the interest rate uncertainty with respect to the debt to be issued, thereby enabling Great Plains Energy to predict with greater assurance what its future interest costs on that debt will be. The T-Lock is accounted for as a cash flow hedge and the fair value is recorded as a current asset or liability with an offsetting entry to OCI, to the extent the hedge is effective, until the forecasted transaction occurs. No ineffectiveness has been recorded on the T-Lock. The pre-tax gain or loss on the T-Lock recorded to OCI will be reclassified to interest expense over the life of the future debt issuance.

In 2005, KCP&L entered into two T-Locks to hedge against interest rate fluctuations on the U.S. Treasury rate component of the $250.0 million 30-year long-term debt that KCP&L issued. The T-Locks settled simultaneously with the issuance of the long-term fixed rate debt. The T-Locks removed the uncertainty with respect to the U.S. Treasury rate component of the debt to be issued, thereby enabling KCP&L to predict with greater assurance what its future interest costs on that debt would be. The T-Locks were accounted for as cash flow hedges and no ineffectiveness was recorded on the T-Locks. A pre-tax gain of $12.0 million on the T-Locks was recorded to OCI and is being reclassified to interest expense over the life of the issued 30-year debt. At December 31, 2006, KCP&L had $11.5 million recorded in OCI for the 2005 T-Locks.

Cash Flow Hedges - Commodity Risk Management
KCP&L's risk management policy is to use derivative 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, 2006, KCP&L had hedged 30% and 9% of its 2007 and 2008 projected natural gas usage for retail load and firm MWh sales, respectively, primarily by utilizing fixed forward physical contracts. 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 during 2006, 2005 and 2004.

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 in 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 hedged its exposure and variability of future cash flows was 5.5 years and 5.0 years at December 31, 2006 and 2005, 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 expense for 2006, 2005 and 2004 included a loss of $26.7 million, a gain of $3.3 million, and a gain of $3.2 million, respectively, due to ineffectiveness of the cash flow hedges.

As part of its commodity-price risk management strategy, Strategic Energy also enters into economic hedges (non-hedging derivatives) that do not qualify for cash flow hedge accounting. The changes in the fair value of these derivative instruments recorded as a component of purchased power expense were losses of $30.0 million, $0.8 million and $1.5 million for 2006, 2005 and 2004, respectively.

The fair value of non-hedging derivatives at December 31, 2006, also includes certain forward contracts at Strategic Energy that were amended during 2005. Prior to being amended, the contracts were accounted for under the NPNS election in accordance with SFAS No. 133. As a result of being amended, the contracts no longer qualify for NPNS exceptions or cash flow hedge accounting and are now accounted for as non-hedging derivatives with the fair value at amendment being recorded as a deferred liability that will be reclassified to net income as the contracts settle. In 2006 and 2005, Strategic Energy amortized $5.1 million and an insignificant amount, respectively, of the deferred liability to purchased power expense related to the delivery of power under the contracts. Strategic Energy will amortize the remaining deferred liability over the remaining original contract lengths, which end in the first quarter of 2008. After the amendment, Strategic Energy is recording the change in fair value of these contracts to purchased power expense.

The notional and recorded fair values of the companies' derivative instruments are summarized in the following table. The fair values of these derivatives are recorded on the consolidated balance sheets.

	December 31			
	2006		2005	
	Notional Contract Amount	Fair Value	Notional Contract Amount	Fair Value
	(millions)			
Great Plains Energy				
Swap contracts				
Cash flow hedges	$ 477.5	$ (38.9)	$ 180.1	$ 27.2
Non-hedging derivatives	37.1	(6.8)	35.5	-
Forward contracts				
Cash flow hedges	871.5	(69.7)	106.5	17.6
Non-hedging derivatives	250.7	(24.8)	178.3	3.6
Anticipated debt issuance				
Forward starting swap	225.0	(0.4)	-	-
Treasury lock	77.6	0.2	-	-
Interest rate swaps				
Fair value hedges	146.5	(1.8)	146.5	(2.6)
Consolidated KCP&L				
Forward contracts				
Cash flow hedges	6.1	(0.5)	-	-
Anticipated debt issuance				
Forward starting swap	225.0	(0.4)	-	-
Interest rate swaps				
Fair value hedges	146.5	(1.8)	146.5	(2.6)

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	
	2006	2005	2006	2005
	(millions)			
Current assets	$ 12.7	$ 35.8	$ 12.0	$ 11.9
Other deferred charges	1.7	11.8	-	-
Other current liabilities	(56.3)	1.6	(1.3)	-
Deferred income taxes	32.1	(20.5)	(4.0)	(4.5)
Other deferred credits	(35.3)	1.0	-	-
Total	$ (45.1)	$ 29.7	$ 6.7	$ 7.4

Great Plains Energy's accumulated OCI in the table above at December 31, 2006, includes $54.3 million that is expected to be reclassified to expenses over the next twelve months. Consolidated KCP&L's accumulated OCI includes an insignificant amount that is expected to be reclassified to expense over the next twelve months.

The amounts reclassified to expenses are summarized in the following table.

	2006	2005	2004
Great Plains Energy		(millions)	
Fuel expense	$ -	$ (0.5)	$ (0.7)
Purchased power expense	54.6	(35.6)	(0.6)
Interest expense	(0.4)	-	-
Minority interest	-	-	0.2
Income taxes	(22.4)	15.1	0.5
OCI	$ 31.8	$ (21.0)	$ (0.6)
Consolidated KCP&L			
Fuel expense	$ -	$ (0.5)	$ (0.7)
Interest expense	(0.4)	-	-
Income taxes	0.2	0.2	0.3
OCI	$ (0.2)	$ (0.3)	$ (0.4)

23. JOINTLY OWNED ELECTRIC UTILITY PLANTS

KCP&L's share of jointly owned electric utility plants in service at December 31, 2006, is detailed in the following table.

	Wolf Creek Unit	LaCygne Units	Iatan No. 1 Unit
	(millions, except MW amounts)		
KCP&L's share	47%	50%	70%
Utility plant in service	$ 1,378	$ 346	$ 268
Accumulated depreciation	734	253	195
Nuclear fuel, net	39	-	-
KCP&L's 2007 accredited capacity-MWs	548	709	460 [a]

[a] The Iatan No. 2 air permit limits KCP&L's accredited capacity of Iatan No. 1 to 460 MWs from 469 MWs until the air quality control equipment included in the comprehensive energy plan is operational.

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 Great Plains Energy's and consolidated KCP&L's financial statements.

24. NEW ACCOUNTING STANDARDS

SFAS No. 157

In September 2006, the Financial Accounting Standards Board (FASB) issued SFAS No. 157, "Fair Value Measurements." This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles (GAAP) and expands disclosures about fair value measurements. The statement does not require any new fair value measurements but provides guidance on how to measure fair value when required. SFAS No. 157 also emphasizes that fair value is a market-based measurement, not an entity-specific measurement, and sets out a fair value hierarchy with the highest priority being quoted prices in active markets. The provisions of this statement are effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years and generally are to be applied prospectively as of the beginning of the fiscal year in which initially applied. Management is currently evaluating the impact of SFAS No. 157 and has not yet determined the impact on Great Plains Energy's and consolidated KCP&L's financial statements.

FIN No. 48
In July 2006, the FASB issued FIN No. 48. See Note 10 for additional information.

25. QUARTERLY OPERATING RESULTS (UNAUDITED)

	Quarter			
Great Plains Energy	**1st**	**2nd**	**3rd**	**4th**
As Adjusted	(millions, except per share amounts)			
2006				
Operating revenue	$ 559.2	$ 642.1	$ 818.5	$ 655.5
Operating income	7.6	73.3	93.6	60.9
Net income (loss)	(1.1)	38.4	55.9	34.4
Basic and diluted earnings (loss) per common share	(0.02)	0.49	0.69	0.42
As Adjusted				
2005				
Operating revenue	$ 545.1	$ 631.7	$ 782.9	$ 645.2
Operating income	42.4	59.6	126.5	54.5
Income from continuing operations	20.5	23.7	89.9	30.1
Net income	20.5	20.1	91.7	30.0
Basic and diluted earnings per common share from continuing operations	0.27	0.31	1.20	0.40
Basic and diluted earnings per common share	0.27	0.26	1.22	0.40

	Quarter			
Consolidated KCP&L	**1st**	**2nd**	**3rd**	**4th**
As Adjusted	(millions)			
2006				
Operating revenue	$ 240.4	$ 290.9	$ 359.3	$ 249.8
Operating income	31.7	69.2	118.4	51.7
Net income	13.0	36.6	69.5	30.2
As Adjusted				
2005				
Operating revenue	$ 233.3	$ 272.1	$ 353.0	$ 272.5
Operating income	25.2	56.0	101.1	67.2
Net income	10.6	27.2	69.7	36.2

Quarterly data is subject to seasonal fluctuations with peak periods occurring in the summer months.

As a result of the retrospective application of FSP No. AUG AIR-1 discussed in Note 5, the following tables provide information to reconcile the quarterly operating results above to amounts originally reported.

Great Plains Energy	Quarter 1st	2nd	3rd	4th
2006	(millions, except per share amounts)			
Operating income as previously reported	$ 6.0	$ 72.0	$ 92.4	N/A
Adjustment	1.6	1.3	1.2	N/A
Net income (loss) as previously reported	(2.1)	37.6	55.2	N/A
Adjustment	1.0	0.8	0.7	N/A
Basic and diluted EPS as previously reported	(0.03)	0.48	0.68	N/A
Adjustment	0.01	0.01	0.01	N/A
2005				
Operating income as previously reported	$ 41.8	$ 62.6	$ 125.5	$ 53.3
Adjustment	0.6	(3.0)	1.0	1.2
Income from continuing operations as previously reported	20.2	25.5	89.1	29.4
Adjustment	0.3	(1.8)	0.8	0.7
Net income as previously reported	20.2	21.9	90.9	29.3
Adjustment	0.3	(1.8)	0.8	0.7
Basic and diluted EPS from continuing operations as previously reported	0.27	0.34	1.19	0.39
Adjustment	-	(0.03)	0.01	0.01
Basic and diluted EPS as previously reported	0.27	0.29	1.21	0.39
Adjustment	-	(0.03)	0.01	0.01

Consolidated KCP&L	Quarter 1st	2nd	3rd	4th
2006	(millions)			
Operating income as previously reported	$ 30.1	$ 67.9	$ 117.2	N/A
Adjustment	1.6	1.3	1.2	N/A
Net income as previously reported	12.0	35.8	68.8	N/A
Adjustment	1.0	0.8	0.7	N/A
2005				
Operating income as previously reported	$ 24.6	$ 59.0	$ 100.1	$ 66.0
Adjustment	0.6	(3.0)	1.0	1.2
Net income as previously reported	10.3	29.0	68.9	35.5
Adjustment	0.3	(1.8)	0.8	0.7

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
Great Plains Energy Incorporated
Kansas City, Missouri

We have audited the accompanying consolidated balance sheets of Great Plains Energy Incorporated and subsidiaries (the "Company") as of December 31, 2006 and 2005, and the related consolidated statements of income, common shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2006. 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, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, 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 8 to the consolidated financial statements, the Company adopted SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans,* on December 31, 2006. As discussed in Note 5 to the consolidated financial statements, the Company adopted FASB Staff Position (FSP) No. AUG AIR-1, *Accounting for Planned Major Maintenance Activities,* in 2006 and retroactively revised the consolidated balance sheet as of December 31, 2005 and the consolidated statements of income, comprehensive income, common shareholders' equity, and cash flows for the years ended December 31, 2005 and 2004, for the change. As discussed in Note 16 to the consolidated financial statements, effective December 31, 2005, the Company changed its method of accounting for conditional asset retirement obligations to adopt FIN 47, *Accounting for Conditional 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, 2006, 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 February 27, 2007 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
February 27, 2007

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Kansas City Power & Light Company
Kansas City, Missouri

We have audited the accompanying consolidated balance sheets of Kansas City Power & Light Company and subsidiaries (the "Company") as of December 31, 2006 and 2005, and the related consolidated statements of income, comprehensive income, common shareholder's equity, and cash flows for each of the three years in the period ended December 31, 2006. 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 Kansas City Power & Light Company and subsidiaries as of December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, 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 8 to the consolidated financial statements, the Company adopted SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans,* on December 31, 2006. As discussed in Note 5 to the consolidated financial statements, the Company adopted FASB Staff Position (FSP) No. AUG AIR-1, *Accounting for Planned Major Maintenance Activities,* in 2006 and retroactively revised the consolidated balance sheet as of December 31, 2005, and the consolidated statements of income, comprehensive income, common shareholder's equity, and cash flows for the years ended December 31, 2005 and 2004, for the change. As discussed in Note 16 to the consolidated financial statements, effective December 31, 2005, the Company changed its method of accounting for conditional asset retirement obligations to adopt FIN 47, *Accounting for Conditional 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, 2006, 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 February 27, 2007, 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
February 27, 2007

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures
Great Plains Energy and KCP&L carried out evaluations of their disclosure controls and procedures (as defined in Rules 13a-15(e) or 15d-15(e) under the Securities Exchange Act of 1934, as amended). These evaluations were conducted under the supervision, and with the participation, of each company's management, including the chief executive officer and chief financial officer of each company and the companies' disclosure committee.

Based upon these evaluations, the chief executive officer and chief financial officer of Great Plains Energy and KCP&L, respectively, have concluded as of the end of the period covered by this report that the disclosure controls and procedures of Great Plains Energy and KCP&L are functioning effectively to provide reasonable assurance that: (i) the information required to be disclosed by the respective companies in the reports that they file or submit under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms; and (ii) the information required to be disclosed by the respective companies in the reports that they file or submit under the Securities Exchange Act of 1934, as amended, is accumulated and communicated to their respective management, including the principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control Over Financial Reporting
There has been no change in Great Plains Energy's or KCP&L's internal control over financial reporting that occurred during the quarterly period ended December 31, 2006, that has materially affected, or is reasonably likely to materially affect, its internal control over financial reporting.

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, 2006. 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, 2006, 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 on Form 10-K, 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
Kansas City, Missouri

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, 2006, 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, 2006, 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, 2006, 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, 2006 of the Company and our report dated February 27, 2007 expressed an unqualified opinion on those financial statements and financial statement schedules and included an explanatory paragraph regarding the Company's adoption of new accounting standards.

/s/DELOITTE & TOUCHE LLP

Kansas City, Missouri
February 27, 2007

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, 2006. 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, 2006, 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 on Form 10-K, 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
Kansas City, Missouri

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, 2006, 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, 2006, 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, 2006, 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 statements schedules as of and for the year ended December 31, 2006 of the Company and our report dated February 27, 2007 expressed an unqualified opinion on those financial statements and financial statement schedules and included an explanatory paragraph regarding the Company's adoption of new accounting standards.

/s/DELOITTE & TOUCHE LLP

Kansas City, Missouri
February 27, 2007

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Great Plains Energy Directors

The information required by this item is incorporated by reference from the Great Plains Energy 2007 Proxy Statement, which will be filed with the SEC no later than April 30, 2007 (Proxy Statement):

- Information regarding the directors of Great Plains Energy required by this item is contained in the Proxy Statement section titled "Election of Directors."

- Information regarding compliance with Section 16(a) of the Securities Exchange Act of 1934 required by this item is contained in the Proxy Statement section titled "Section 16(a) Beneficial Ownership Reporting Compliance."
- Information regarding the Audit Committee of Great Plains Energy required by this item is contained in the Proxy Statement section titled "Corporate Governance."

Great Plains Energy and KCP&L Executive Officers
Information required by this item regarding the executive officers of Great Plains Energy and KCP&L is contained in this report in the Part I, Item 1 sections titled "Officers of Great Plains Energy" and "Officers of KCP&L".

Great Plains Energy and KCP&L Code of Ethics
The Company has adopted a Code of Business Conduct and Ethics (Code), which applies to all directors, officers and employees of Great Plains Energy, KCP&L and their subsidiaries. The Code is posted on the investor relations page of our Internet websites at www.greatplainsenergy.com and www.kcpl.com. A copy of the Code is available, without charge, upon written request to Corporate Secretary, Great Plains Energy Incorporated, 1201 Walnut, Kansas City, Missouri 64106. Great Plains Energy and KCP&L intend to satisfy the disclosure requirements under Item 5.05 of Form 8-K regarding an amendment to, or a waiver from, a provision of the Code that applies to the principal executive officer, principal financial officer, principal accounting officer or controller of those companies by posting such information on the investor relations page of their Internet websites.

Other KCP&L Information
The other information required by this item regarding KCP&L has been omitted in reliance on General Instruction (I).

ITEM 11. EXECUTIVE COMPENSATION

GREAT PLAINS ENERGY
The information required by this item regarding compensation of Great Plains Energy directors and named executive officers contained in the sections titled "Corporate Governance," "Executive Compensation," "Director Compensation," "Compensation Discussion and Analysis" and "Compensation Committee Report" of the Proxy Statement is incorporated by reference.

KCP&L
The information required by this item regarding KCP&L has been omitted in reliance on General Instruction (I).

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

GREAT PLAINS ENERGY
The information required by this item regarding security ownership of the directors and executive officers of Great Plains Energy contained in the section titled "Security Ownership of Certain Beneficial Owners, Directors and Officers" of the Proxy Statement is incorporated by reference.

KCP&L
The information required by this item regarding KCP&L has been omitted in reliance on General Instruction (I).

Equity Compensation Plan
The information required by this item regarding Great Plains Energy's equity compensation plan is in Item 5. Market for the Registrants' Common Equity and Related Shareholder Matters, of this report and is incorporated by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

GREAT PLAINS ENERGY
The information required by this item contained in the sections titled "Director Independence" and, if applicable, "Certain Relationships and Related Transactions" of the Proxy Statement is incorporated by reference.

KCP&L
The information required by this item regarding KCP&L has been omitted in reliance on General Instruction (I).

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

GREAT PLAINS ENERGY
The information required by this item regarding the independent auditors of Great Plains Energy and its subsidiaries contained in the section titled "Audit Committee Report" of the Proxy Statement is incorporated by reference.

KCP&L
The Audit Committee of the Great Plains Energy Board functions as the Audit Committee of KCP&L. The following table sets forth the aggregate fees billed by Deloitte & Touche LLP for audit services rendered in connection with the consolidated financial statements and reports for 2006 and 2005 and for other services rendered during 2006 and 2005 on behalf of KCP&L and its subsidiaries, as well as all out-of-pocket costs incurred in connection with these services:

Fee Category	2006	2005
Audit Fees	$ 984,256	$ 1,075,986
Audit-Related Fees	44,200	62,251
Tax Fees	21,831	24,307
All Other Fees	-	21,100
Total Fees	$ 1,050,287	$ 1,183,644

Audit Fees: Consists of fees billed for professional services rendered for the audits of the annual consolidated financial statements of the Company and its subsidiaries and reviews of the interim condensed consolidated financial statements included in quarterly reports. Audit fees also include: services provided by Deloitte & Touche LLP in connection with statutory and regulatory filings or engagements; audit reports on audits of the effectiveness of internal control over financial reporting and on management's assessment of the effectiveness of internal control over financial reporting and other attest services, except those not required by statute or regulation; services related to filings with the Securities and Exchange Commission, including comfort letter, consents and assistance with and review of documents filed with the Securities and Exchange Commission; and accounting research in support of the audit.

Audit-Related Fees: Consists of fees billed for assurance and related services that are reasonably related to the performance of the audit or review of consolidated financial statements of KCP&L and its

subsidiaries and are not reported under "Audit Fees". These services include consultation concerning financial accounting and reporting standards.

Tax Fees: Consists of fees billed for tax compliance and related support of tax returns and other tax services, including assistance with tax audits, and tax research and planning.

All Other Fees: Consists of fees for all other services other than those reported above. These services included development and facilitation of a group training course in 2005.

Audit Committee Pre-Approval of Audit and Permissible Non-Audit Services of Independent Auditors

The Audit Committee pre-approves all audit and permissible non-audit services provided by the independent auditor to KCP&L and its subsidiaries. These services may include audit services, audit-related services, tax services and other services. The Audit Committee has adopted for KCP&L and its subsidiaries policies and procedures for the pre-approval of services provided by the independent auditor. Under these policies and procedures, the Audit Committee may pre-approve certain types of services, up to aggregate fee levels established by the Audit Committee. The Audit Committee as well may specifically approve audit and permissible non-audit services on a case-by-case basis. Any proposed service within a pre-approved type of service that would cause the applicable fee level to be exceeded cannot be provided unless the Audit Committee either amends the applicable fee level or specifically approves the proposed service. Pre-approval is generally provided for up to one year, unless the Audit Committee specifically provides for a different period. The Audit Committee receives quarterly reports regarding the pre-approved services performed by the independent auditor. The Chairman of the Audit Committee may between meetings pre-approve audit and non-audit services provided by the independent auditor, and report such pre-approval at the next Audit Committee meeting.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

Financial Statements

KCP&L

Financial Statement Schedules

Great Plains Energy

KCP&L

Exhibits

Great Plains Energy Documents

Exhibit Number		Description of Document
2.1.1	*	Agreement and Plan of Merger among Kansas City Power & Light Company, Great Plains Energy Incorporated and KCP&L Merger Sub Incorporated dated as of October 1, 2001 (Exhibit 2 to Form 8-K dated October 1, 2001).
2.1.2	*	Agreement and Plan of Merger among Aquila, Inc., Great Plains Energy Incorporated, Gregory Acquisition Corp., and Black Hills Corporation dated as of February 6, 2007 (Exhibit 2.1 to Form 8-K dated February 7, 2007).
3.1.1	*	Articles of Incorporation of Great Plains Energy Incorporated dated as of February 26, 2001 (Exhibit 3.i to Form 8-K filed October 1, 2001).
3.1.2	*	By-laws of Great Plains Energy Incorporated, as amended September 16, 2003 (Exhibit 3.1 to Form 10-Q for the quarter ended September 30, 2003).
4.1.1	*	Resolution of Board of Directors Establishing 3.80% Cumulative Preferred Stock (Exhibit 2-R to Registration Statement, Registration No. 2-40239).
4.1.2	*	Resolution of Board of Directors Establishing 4.50% Cumulative Preferred Stock (Exhibit 2-T to Registration Statement, Registration No. 2-40239).

4.1.3	*	Resolution of Board of Directors Establishing 4.20% Cumulative Preferred Stock (Exhibit 2-U to Registration Statement, Registration No. 2-40239).
4.1.4	*	Resolution of Board of Directors Establishing 4.35% Cumulative Preferred Stock (Exhibit 2-V to Registration Statement, Registration No. 2-40239).
4.1.5	*	Pledge Agreement, dated June 14, 2004, between Great Plains Energy Incorporated and BNY Midwest Trust Company, as Collateral Agent, Custodial Agent and Securities Intermediary and BNY Midwest Trust Company, as Purchase Contract Agent (Exhibit 4.2 to Form 8-A/A, dated June 14, 2004).
4.1.6	*	Indenture, dated June 1, 2004, between Great Plains Energy Incorporated and BNY Midwest Trust Company, as Trustee (Exhibit 4.5 to Form 8-A/A, dated June 14, 2004).
4.1.7	*	First Supplemental Indenture, dated June 14, 2004, between Great Plains Energy Incorporated and BNY Midwest Trust Company, as Trustee (Exhibit 4.5 to Form 8-A/A, dated June 14, 2004).
4.1.8	*	Form of Income PRIDES (included in Exhibit 4.1 to Form 8-A/A, dated June 14, 2004, as Exhibit A thereto).
4.1.9	*	Confirmation of Forward Stock Sale Transaction between Great Plains Energy Incorporated and Merrill Lynch Financial Markets, Inc., dated May 17, 2006 (Exhibit 1.2 to Form 8-K filed May 23, 2006).
10.1.1	*+	Amended Long-Term Incentive Plan, effective as of May 7, 2002 (Exhibit 10.1.a to Form 10-K for the year ended December 31, 2002).
10.1.2	*+	Great Plains Energy Incorporated Long-Term Incentive Plan Awards Standards and Administration effective as of February 7, 2006 (Exhibit 10.1.b to Form 10-K for the year ended December 31, 2005).
10.1.3	*+	Form of Restricted Stock Agreement Pursuant to the Great Plains Energy Incorporated Long-Term Incentive Plan Effective May 7, 2002 (Exhibit 10.1 to Form 8-K dated February 4, 2005).
10.1.4	*+	Form of Restricted Stock Agreement Pursuant to the Great Plains Energy Incorporated Long-Term Incentive Plan Effective May 7, 2002 (Exhibit 10.2 to Form 8-K dated February 4, 2005).
10.1.5	*+	Form of Restricted Stock Agreement Pursuant to the Great Plains Energy Incorporated Long-Term Incentive Plan Effective May 7, 2002 (Exhibit 10.1.e to Form 10-K for the year ended December 31, 2005).
10.1.6	+	Form of Restricted Stock Agreement Pursuant to the Great Plains Energy Incorporated Long-Term Incentive Plan Effective May 7, 2002.
10.1.7	*+	Form of Performance Share Agreement Pursuant to the Great Plains Energy Incorporated Long-Term Incentive Plan Effective May 7, 2002 (Exhibit 10.1.b to Form 10-Q for the quarter ended March 31, 2005).
10.1.8	*+	Form of Performance Share Agreement Pursuant to the Great Plains Energy Incorporated Long-Term Incentive Plan Effective May 7, 2002 (Exhibit 10.1.c to Form 10-Q for the quarter ended March 31, 2005).
10.1.9	*+	Form of Performance Share Agreement Pursuant to the Great Plains Energy Incorporated Long-Term Incentive Plan Effective May 7, 2002 (Exhibit 10.1.h to Form 10-K for the year ended December 31, 2005).

10.1.10	+	Form of Performance Share Agreement Pursuant to the Great Plains Energy Incorporated Long-Term Incentive Plan Effective May 7, 2002.
10.1.11	+	Form of Performance Share Agreement Pursuant to the Great Plains Energy Incorporated Long-Term Incentive Plan Effective May 7, 2002.
10.1.12	*+	Strategic Energy, L.L.C. Long-Term Incentive Plan Grants 2005, Amended May 2, 2005 (Exhibit 10.1.f to Form 10-Q for the quarter ended March 31, 2005).
10.1.13	*+	Strategic Energy, L.L.C. Long-Term Incentive Plan Grants 2005, as amended May 2, 2005 and October 31, 2006 (Exhibit 10.1.g to Form 10-Q for the quarter ended September 30, 2006).
10.1.14	*+	Strategic Energy, L.L.C. Executive Long-Term Incentive Plan 2006 (Exhibit 10.1.j to Form 10-K for the year ended December 31, 2005).
10.1.15	*+	Great Plains Energy Incorporated/Kansas City Power & Light Company Annual Incentive Plan 2005, Amended May 3, 2005 (Exhibit 10.1.c to Form 10-Q for the quarter ended March 31, 2005).
10.1.16	*+	Great Plains Energy Incorporated Kansas City Power & Light Company Annual Incentive Plan amended as of January 1, 2006 (Exhibit 10.1.l to Form 10-K for the year ended December 31, 2005).
10.1.17	*+	Strategic Energy, L.L.C. Annual Incentive Plan dated January 1, 2006 (Exhibit 10.1.m to Form 10-K for the year ended December 31, 2005).
10.1.18	*+	Strategic Energy, L.L.C. Annual Incentive Plan 2006 goals as amended October 31, 2006 (Exhibit 10.1.h to Form 10-Q for the quarter ended September 30, 2006).
10.1.19	+	Great Plains Energy Incorporated Kansas City Power & Light Company Annual Incentive Plan amended effective as of January 1, 2007.
10.1.20	+	Strategic Energy, L.L.C. Executive Committee Annual Incentive Plan dated as of January 1, 2007.
10.1.21	+	Strategic Energy, L.L.C. Executive Committee Long-Term Incentive Plan dated as of January 1, 2007.
10.1.22	*+	Form of Indemnification Agreement with each officer and director (Exhibit 10-f to Form 10-K for year ended December 31, 1995).
10.1.23	*+	Form of Conforming Amendment to Indemnification Agreement with each officer and director (Exhibit 10.1.a to Form 10-Q for the quarter ended March 31, 2003).
10.1.24	*+	Form of Indemnification Agreement with officers and directors (Exhibit 10.1.p to Form 10-K for the year ended December 31, 2005).
10.1.25	*+	Form of Restated Severance Agreement dated January 2000 with certain executive officers (Exhibit 10-e to Form 10-K for the year ended December 31, 2000).
10.1.26	*+	Form of Conforming Amendment to Severance Agreements with certain executive officers (Exhibit 10.1.b to Form 10-Q for the quarter ended March 31, 2003).
10.1.27	*+	Form of Change in Control Severance Agreement with Michael J. Chesser (Exhibit 10.1.a to Form 10-Q for the quarter ended September 30, 2006).
10.1.28	*+	Form of Change in Control Severance Agreement with John R. Marshall (Exhibit 10.1.c to Form 10-Q for the quarter ended September 30, 2006).

10.1.29	*+	Form of Change in Control Severance Agreement with Shahid Malik (Exhibit 10.1.d to Form 10-Q for the quarter ended September 30, 2006).
10.1.30	*+	Form of Change in Control Severance Agreement with other executive officers of Great Plains Energy Incorporated and Kansas City Power & Light Company (Exhibit 10.1.e to Form 10-Q for the quarter ended September 30, 2006).
10.1.31	*+	Great Plains Energy Incorporated Supplemental Executive Retirement Plan, as amended and restated effective October 1, 2003 (Exhibit 10.1.a to Form 10-Q for the quarter ended September 30, 2003).
10.1.32	*+	Nonqualified Deferred Compensation Plan (Exhibit 10-b to Form 10-Q for the quarter ended March 31, 2000).
10.1.33	+	Description of Compensation Arrangements with Directors and Certain Executive Officers.
10.1.34	*+	Employment Agreement among Strategic Energy, L.L.C., Great Plains Energy Incorporated and Shahid J. Malik, dated as of November 10, 2004 (Exhibit 10.1.p to Form 10-K for the year ended December 31, 2004).
10.1.35	*+	Severance Agreement among Strategic Energy, L.L.C., Great Plains Energy Incorporated and Shahid J. Malik, dated as of November 10, 2004 (Exhibit 10.1.q to Form 10-K for the year ended December 31, 2004).
10.1.36	*	First Amended and Restated Joint Plan under Chapter 11 of the United States Bankruptcy Code dated March 31, 2003, of Digital Teleport Inc., DTI Holdings, Inc. and Digital Teleport of Virginia, Inc. (Exhibit 10.1.e to Form 10-Q for the quarter ended March 31, 2003).
10.1.37	*	Credit Agreement dated as of May 11, 2006, among Great Plains Energy Incorporated, Bank of America, N.A., JPMorgan Chase Bank, N.A., BNP Paribas, The Bank of Tokyo-Mitsubishi UFJ, Limited, Chicago Branch, Wachovia Bank N.A., The Bank of New York, Keybank National Association, The Bank of Nova Scotia, UMB Bank, N.A., and Commerce Bank, N.A (Exhibit 10.1.a to Form 10-Q for the quarter ended June 30, 2006).
10.1.38	*	Amended and Restated Credit Agreement, dated as of July 2, 2004, by and among Strategic Energy, L.L.C., LaSalle Bank National Association, PNC Bank, National Association, Citizens Bank of Pennsylvania, Provident Bank, Fifth Third Bank and Sky Bank. (Exhibit 10.2 to Form 10-Q for the quarter ended June 30, 2004).
10.1.39	*	Amendment No. 1 dated as of December 20, 2005, to Amended and Restated Credit Agreement, dated as of July 2, 2004, by and among Strategic Energy, L.L.C., LaSalle Bank National Association, PNC Bank, National Association, Citizens Bank of Pennsylvania, Provident Bank, Fifth Third Bank, First National Bank of Pennsylvania and Sky Bank (Exhibit 10.1.bb to Form 10-K for the year ended December 31, 2005).
10.1.40	*	Consent dated as of May 31, 2006, to Amended and Restated Credit Agreement, dated as of July 2, 2004, by and among Strategic Energy, L.L.C., LaSalle Bank National Association, PNC Bank, National Association, Citizens Bank of Pennsylvania, National City Bank of Pennsylvania, Fifth Third Bank, Sky Bank and First National Bank of Pennsylvania (Exhibit 10.1.b to Form 10-Q for the quarter ended June 30, 2006).

10.1.41		Waiver and Amendment dated as of December 6, 2006, to Amended and Restated Credit Agreement, dated as of July 2, 2004, by and among Strategic Energy, L.L.C., LaSalle Bank National Association, PNC Bank, National Association, Citizens Bank of Pennsylvania, National City Bank of Pennsylvania, Fifth Third Bank, Sky Bank and First National Bank of Pennsylvania.
10.1.42	*	Amended and Restated Limited Guaranty dated as of July 2, 2004, by Great Plains Energy Incorporated in favor of the lenders under the Amended and Restated Credit Agreement dated as of July 2, 2004 among Strategic Energy, L.L.C. and the financial institutions from time to time parties thereto. (Exhibit 10.3 to Form 10-Q for the quarter ended June 30, 2004).
10.1.43	*	Amendment dated as of October 2, 2006, to Amended and Restated Limited Guaranty dated as of July 2, 2004, by Great Plains Energy Incorporated in favor of the lenders under the Amended and Restated Credit Agreement dated as of July 2, 2004, among Strategic Energy, L.L.C. and the financial institutions from time to time parties thereto (Exhibit 10.1.e to Form 10-Q for the quarter ended September 30, 2006).
10.1.44	*	General Agreement of Indemnity issued by Great Plains Energy Incorporated and Strategic Energy, L.L.C. in favor of Federal Insurance Company and subsidiary or affiliated insurers dated May 23, 2002 (Exhibit 10.1.a. to Form 10-Q for the quarter ended June 30, 2002).
10.1.45	*	Agreement of Indemnity issued by Great Plains Energy Incorporated and Strategic Energy, L.L.C. in favor of Federal Insurance Company and subsidiary or affiliated insurers dated May 23, 2002 (Exhibit 10.1.b. to Form 10-Q for the quarter ended June 30, 2002).
10.1.46	*	Agreement between Great Plains Energy Incorporated and Andrea F. Bielsker dated March 4, 2005 (Exhibit 10.1.jj to Form 10-K for the year ended December 31, 2004).
10.1.47	*	Agreement between Great Plains Energy Incorporated and Jeanie Sell Latz dated April 5, 2005 (Exhibit 10.1 to Form 8-K dated April 5, 2005).
10.1.48	*	Asset Purchase Agreement by and among Aquila, Inc., Black Hills Corporation, Great Plains Energy Incorporated, and Gregory Acquisition Corp., dated February 6, 2007 (Exhibit 10.1 to Form 8-K dated February 7, 2007).
10.1.49	*	Partnership Interests Purchase Agreement by and among Aquila, Inc., Aquila Colorado, LLC, Black Hills Corporation, Great Plains Energy Incorporated, and Gregory Acquisition Corp., dated February 6, 2007 (Exhibit 10.2 to Form 8-K dated February 7, 2007).
10.1.50	*+	Form of Conforming Amendment to Severance Agreements with William H. Downey (Exhibit 10.1.b to Form 10-Q for the quarter ended September 30, 2006).
12.1		Computation of Ratio of Earnings to Fixed Charges.
21.1		List of Subsidiaries of Great Plains Energy Incorporated.
23.1.a		Consent of Counsel.
23.1.b		Consent of Independent Registered Public Accounting Firm.
24.1		Powers of Attorney.
31.1.a		Rule 13a-14(a)/15d-14(a) Certifications of Michael J. Chesser.

31.1.b	Rule 13a-14(a)/15d-14(a) Certifications of Terry Bassham.
32.1	Section 1350 Certifications.

*Filed with the SEC as exhibits to prior SEC filings and are incorporated herein by reference and made a part hereof. The SEC filing and the exhibit number of the documents so filed, and incorporated herein by reference, are stated in parenthesis in the description of such exhibit.

+ Indicates management contract or compensatory plan or arrangement.

Copies of any of the exhibits filed with the SEC in connection with this document may be obtained from Great Plains Energy upon written request.

Great Plains Energy agrees to furnish to the SEC upon request any instrument with respect to long-term debt as to which the total amount of securities authorized does not exceed 10% of total assets of Great Plains Energy and its subsidiaries on a consolidated basis.

KCP&L Documents

Exhibit Number		Description of Document
2.2	*	Agreement and Plan of Merger among Kansas City Power & Light Company, Great Plains Energy Incorporated and KCP&L Merger Sub Incorporated dated as of October 1, 2001 (Exhibit 2 to Form 8-K dated October 1, 2001).
3.2.1	*	Restated Articles of Consolidation of Kansas City Power & Light Company, as amended October 1, 2001 (Exhibit 3-(i) to Form 10-Q for the quarter ended September 30, 2001).
3.2.2	*	By-laws of Kansas City Power & Light Company, as amended November 1, 2005 (Exhibit 3.2.b to Form 10-K for the year ended December 31, 2005).
4.2.1	*	General Mortgage and Deed of Trust dated as of December 1, 1986, between Kansas City Power & Light Company and UMB Bank, n.a. (formerly United Missouri Bank of Kansas City, N.A.), Trustee (Exhibit 4-bb to Form 10-K for the year ended December 31, 1986).
4.2.2	*	Fourth Supplemental Indenture dated as of February 15, 1992, to Indenture dated as of December 1, 1986 (Exhibit 4-y to Form 10-K for the year ended December 31, 1991).
4.2.3	*	Fifth Supplemental Indenture dated as of September 15, 1992, to Indenture dated as of December 1, 1986 (Exhibit 4-a to quarterly report on Form 10-Q for the quarter ended September 30, 1992).
4.2.4	*	Seventh Supplemental Indenture dated as of October 1, 1993, to Indenture dated as of December 1, 1986 (Exhibit 4-a to quarterly report on Form 10-Q for the quarter ended September 30, 1993).
4.2.5	*	Eighth Supplemental Indenture dated as of December 1, 1993, to Indenture dated as of December 1, 1986 (Exhibit 4 to Registration Statement, Registration No. 33-51799).

4.2.6	*	Eleventh Supplemental Indenture dated as of August 15, 2005, to the General Mortgage and Deed of Trust dated as of December 1, 1986, between Kansas City Power & Light Company and UMB Bank, n.a. (formerly United Missouri Bank of Kansas City, N.A.), Trustee (Exhibit 4.2 to Form 10-Q for the quarter ended September 30, 2005).
4.2.7	*	Indenture for Medium-Term Note Program dated as of February 15, 1992, between Kansas City Power & Light Company and The Bank of New York (Exhibit 4-bb to Registration Statement, Registration No. 33-45736).
4.2.8	*	Indenture for $150 million aggregate principal amount of 6.50% Senior Notes due November 15, 2011 and $250 million aggregate principal amount of 7.125% Senior Notes due December 15, 2005 dated as of December 1, 2000, between Kansas City Power & Light Company and The Bank of New York (Exhibit 4-a to Report on Form 8-K dated December 18, 2000).
4.2.9	*	Indenture dated March 1, 2002 between The Bank of New York and Kansas City Power & Light Company (Exhibit 4.1.b. to Form 10-Q for the quarter ended March 31, 2002).
4.2.10	*	Supplemental Indenture No. 1 dated as of November 15, 2005, to indenture dated March 1, 2002 between The Bank of New York and Kansas City Power & Light Company (Exhibit 4.2.j to Form 10-K for the year ended December 31, 2005).
4.2.11	*	Registration Rights Agreement dated as of November 17, 2005, among Kansas City Power & Light Company, and BNP Paribas Securities Corp. and J.P. Morgan Securities Inc. as representatives of the several initial purchasers (Exhibit 4.2.k to Form 10-K for the year ended December 31, 2005).
10.2.1	*	Insurance agreement between Kansas City Power & Light Company and XL Capital Assurance Inc., dated December 5, 2002 (Exhibit 10.2.f to Form 10-K for the year ended December 31, 2002).
10.2.2	*	Insurance Agreement dated as of August 1, 2004, between Kansas City Power & Light Company and XL Capital Assurance Inc. (Exhibit 10.2 to Form 10-Q for the quarter ended September 30, 2004).
10.2.3	*	Insurance Agreement dated as of September 1, 2005, between Kansas City Power & Light Company and XL Capital Assurance Inc. (Exhibit 10.2.e to Form 10-K for the year ended December 31, 2005).
10.2.4	*	Insurance Agreement dated as of September 1, 2005, between Kansas City Power & Light Company and XL Capital Assurance Inc. (Exhibit 10.2.e to Form 10-K for the year ended December 31, 2005).
10.2.5	*	Iatan Unit 2 and Common Facilities Ownership Agreement, dated as of May 19, 2006, among Kansas City Power & Light Company, Aquila, Inc., The Empire District Electric Company, Kansas Electric Power Cooperative, Inc., and Missouri Joint Municipal Electric Utility Commission (Exhibit 10.2.a to Form 10-Q for the quarter ended June 30, 2006).

10.2.6	*	Contract between Kansas City Power & Light Company and ALSTOM Power Inc. for Engineering, Procurement, and Constructions Services for Air Quality Control Systems and Selective Catalytic Reduction Systems at Iatan Generating Station Units 1 and 2 and the Pulverized Coal-Fired Boiler at Iatan Generating Station Unit 2, dated as of August 10, 2006 (Exhibit 10.2.a to Form 10-Q for the quarter ended September 30, 2006).
10.2.7	*	Credit Agreement dated as of May 11, 2006, among Kansas City Power & Light Company, Bank of America, N.A., JPMorgan Chase Bank, N.A., BNP Paribas, The Bank of Tokyo-Mitsubishi UFJ, Limited, Chicago Branch, Wachovia Bank N.A., The Bank of New York, Keybank National Association, The Bank of Nova Scotia, UMB Bank, N.A., and Commerce Bank, N.A (Exhibit 10.2.b to Form 10-Q for the quarter ended June 30, 2006).
10.2.8	*	Stipulation and Agreement dated March 28, 2005, among Kansas City Power & Light Company, Staff of the Missouri Public Service Commission, Office of the Public Counsel, Missouri Department of Natural Resources, Praxair, Inc., Missouri Independent Energy Consumers, Ford Motor Company, Aquila, Inc., The Empire District Electric Company, and Missouri Joint Municipal Electric Utility Commission (Exhibit 10.2 to Form 10-Q for the quarter ended March 31, 2005).
10.2.9	*	Stipulation and Agreement filed April 27, 2005, among Kansas City Power & Light Company, the Staff of the State Corporation Commission of the State of Kansas, Sprint, Inc., and the Kansas Hospital Association (Exhibit 10.2.a to Form 10-Q for the quarter ended June 30, 2005).
10.2.10	*	Stipulation and Agreement dated as of September 29, 2006, among Kansas City Power & Light Company, the Staff of the Kansas Corporation Commission, the Citizens' Utility Ratepayer Board, Wal-Mart Stores Inc. and the International Brotherhood of Electrical Workers, Local Union Nos. 412, 1464 and 1613 (Exhibit 10.2.b to Form 10-Q for the quarter ended September 30, 2006).
10.2.11	*	Purchase and Sale Agreement dated as of July 1, 2005, between Kansas City Power & Light Company, as Originator, and Kansas City Power & Light Receivables Company, as Buyer (Exhibit 10.2.b to Form 10-Q for the quarter ended June 30, 2005).
10.2.12	*	Receivables Sale Agreement dated as of July 1, 2005, among Kansas City Power & Light Receivables Company, as the Seller, Kansas City Power & Light Company, as the Initial Collection Agent, The Bank of Tokyo-Mitsubishi, Ltd., New York Branch, as the Agent, and Victory Receivables Corporation (Exhibit 10.2.c to Form 10-Q for the quarter ended June 30, 2005).
12.2		Computation of Ratio of Earnings to Fixed Charges.
23.2.a		Consent of Counsel.
23.2.b		Consent of Independent Registered Public Accounting Firm.
24.2		Powers of Attorney.
31.2.a		Rule 13a-14(a)/15d-14(a) Certifications of William H. Downey.
31.2.b		Rule 13a-14(a)/15d-14(a) Certifications of Terry Bassham.
32.2		Section 1350 Certifications.

* Filed with the SEC as exhibits to prior SEC filings and are incorporated herein by reference and made a part hereof. The SEC filings and the exhibit number of the documents so filed, and incorporated herein by reference, are stated in parenthesis in the description of such exhibit.

Copies of any of the exhibits filed with the SEC in connection with this document may be obtained from KCP&L upon written request.

KCP&L agrees to furnish to the SEC upon request any instrument with respect to long-term debt as to which the total amount of securities authorized does not exceed 10% of total assets of KCP&L and its subsidiaries on a consolidated basis.

Schedule I – Parent Company Financial Statements

GREAT PLAINS ENERGY INCORPORATED
Income Statements of Parent Company

Year Ended December 31	**2006**	As Adjusted 2005	As Adjusted 2004
		(millions)	
Operating Expenses			
Other	**$ 7.1**	$ 7.1	$ 8.5
General taxes	**0.3**	0.3	0.2
Total	**7.4**	7.4	8.7
Operating loss	**(7.4)**	(7.4)	(8.7)
Equity from earnings in subsidiaries	**143.0**	178.2	200.9
Non-operating income	**1.1**	1.6	2.3
Non-operating expenses	**-**	(0.1)	(0.2)
Interest charges	**(8.9)**	(9.4)	(8.1)
Income before income taxes	**127.8**	162.9	186.2
Income taxes	**(0.2)**	(0.6)	(3.7)
Net income	**127.6**	162.3	182.5
Preferred stock dividend requirements	**1.6**	1.6	1.6
Earnings available for common shareholders	**$ 126.0**	$ 160.7	$ 180.9
Average number of basic common shares outstanding	**78.0**	74.6	72.0
Average number of diluted common shares outstanding	**78.2**	74.7	72.1
Basic earnings per common share	**$ 1.62**	$ 2.15	$ 2.51
Diluted earnings per common share	**$ 1.61**	$ 2.15	$ 2.51
Cash dividends per common share	**$ 1.66**	$ 1.66	$ 1.66

The accompanying Notes to Financial Statements of Parent Company are an integral part of these statements.

GREAT PLAINS ENERGY INCORPORATED
Balance Sheets of Parent Company

December 31	2006	As Adjusted 2005
ASSETS	(millions)	
Current Assets		
Cash and cash equivalents	$ 5.8	$ 2.0
Accounts receivable from subsidiaries	1.6	1.0
Notes receivable from subsidiaries	2.3	5.4
Taxes receivable	1.9	1.8
Other	0.5	0.5
Total	12.1	10.7
Nonutility Property and Investments		
Investment in KCP&L	1,383.1	1,151.6
Investments in other subsidiaries	178.6	288.0
Total	1,561.7	1,439.6
Deferred Charges and Other Assets		
Deferred Income Taxes	0.8	-
Other	4.6	2.0
Total	5.4	2.0
Total	$ 1,579.2	$ 1,452.3

The accompanying Notes to Financial Statements of Parent Company are an integral part of these statements.

GREAT PLAINS ENERGY INCORPORATED
Balance Sheets of Parent Company

December 31	2006	As Adjusted 2005
LIABILITIES AND CAPITALIZATION	(millions)	
Current Liabilities		
Notes payable	$ -	$ 6.0
Notes payable to subsidiaries	13.2	-
Current maturities of long-term debt	163.6	-
Accounts payable to subsidiaries	15.6	0.5
Accounts payable	-	0.1
Accrued interest	1.6	1.7
Other	1.9	6.5
Total	195.9	14.8
Deferred Credits and Other Liabilities		
Payable to subsidiaries	2.1	-
Other	0.3	0.9
Total	2.4	0.9
Capitalization		
Common shareholders' equity		
Common stock 150,000,000 shares authorized without par value		
80,405,035 and 74,783,824 shares issued, stated value	896.8	744.4
Retained earnings	493.4	498.6
Treasury stock-53,499 and 43,376 shares, at cost	(1.6)	(1.3)
Accumulated other comprehensive loss	(46.7)	(7.7)
Total	1,341.9	1,234.0
Cumulative preferred stock $100 par value		
3.80% - 100,000 shares issued	10.0	10.0
4.50% - 100,000 shares issued	10.0	10.0
4.20% - 70,000 shares issued	7.0	7.0
4.35% - 120,000 shares issued	12.0	12.0
Total	39.0	39.0
Long-term debt	-	163.6
Total	1,380.9	1,436.6
Commitments and Contingencies		
Total	$ 1,579.2	$ 1,452.3

The accompanying Notes to Financial Statements of Parent Company are an integral part of these statements.

GREAT PLAINS ENERGY INCORPORATED
Statements of Cash Flows of Parent Company

Year Ended December 31	2006	As Adjusted 2005	As Adjusted 2004
Cash Flows from Operating Activities		(millions)	
Net income	**$ 127.6**	$ 162.3	$ 182.5
Adjustments to reconcile income to net cash from operating activities:			
Amortization	**0.6**	0.6	1.8
Deferred income taxes, net	**-**	-	0.6
Equity in earnings from subsidiaries	**(143.0)**	(178.2)	(200.9)
Cash flows affected by changes in:			
Accounts receivable from subsidiaries	**(0.6)**	(0.4)	4.3
Taxes receivable	**(0.1)**	2.6	(4.4)
Accounts payable to subsidiaries	**15.1**	0.5	(0.8)
Other accounts payable	**(0.1)**	0.1	-
Accrued taxes	**-**	-	(7.5)
Accrued interest	**(0.1)**	0.1	0.8
Cash dividends from subsidiaries	**118.0**	133.9	210.1
Other	**1.7**	3.0	0.4
Net cash from operating activities	**119.1**	124.5	186.9
Cash Flows from Investing Activities			
Equity contributions to subsidiaries	**(134.6)**	-	(305.0)
Net change in notes receivable from subsidiaries	**3.1**	11.0	7.8
Net cash from investing activities	**(131.5)**	11.0	(297.2)
Cash Flows from Financing Activities			
Issuance of common stock	**153.6**	9.1	153.7
Issuance of long-term debt	**-**	-	163.6
Issuance fees	**(5.7)**	-	(12.1)
Net change in notes payable to subsidiaries	**13.2**	-	-
Net change in short-term borrowings	**(6.0)**	(14.0)	(67.0)
Dividends paid	**(132.7)**	(125.5)	(120.8)
Other financing activities	**(6.2)**	(5.9)	(5.0)
Net cash from financing activities	**16.2**	(136.3)	112.4
Net Change in Cash and Cash Equivalents	**3.8**	(0.8)	2.1
Cash and Cash Equivalents at Beginning of Year	**2.0**	2.8	0.7
Cash and Cash Equivalents at End of Year	**$ 5.8**	$ 2.0	$ 2.8

The accompanying Notes to Financial Statements of Parent Company are an integral part of these statements.

GREAT PLAINS ENERGY INCORPORATED
Statements of Common Shareholders' Equity of Parent Company
Statements of Comprehensive Income of Parent Company

Incorporated by reference is Great Plains Energy Consolidated Statements of Common Shareholders' Equity and Consolidated Statements of Comprehensive Income.

GREAT PLAINS ENERGY INCORPORATED
NOTES TO FINANCIAL STATEMENTS OF PARENT COMPANY

The Great Plains Energy Incorporated Notes to Consolidated Financial Statements in Part II, Item 8 should be read in conjunction with the Great Plains Energy Incorporated Parent Company Financial Statements.

Schedule II – Valuation and Qualifying Accounts and Reserves

Great Plains Energy
Valuation and Qualifying Accounts
Years Ended December 31, 2006, 2005 and 2004

Description	Balance At Beginning Of Period	Additions: Charged To Costs And Expenses	Additions: Charged To Other Accounts		Deductions		Balance At End Of Period
			(millions)				
Year Ended December 31, 2006							
Allowance for uncollectible accounts	$ 6.9	$ 12.3	$ 5.7	(a)	$ 16.6	(b)	$ 8.3
Legal reserves	5.9	4.9	0.1		4.8	(c)	6.1
Environmental reserves	0.3	-	-		-		0.3
Uncertain tax positions	4.6	1.1	-		1.0	(d)	4.7
Year Ended December 31, 2005							
Allowance for uncollectible accounts	$ 6.4	$ 6.9	$ 5.0	(a)	$ 11.4	(b)	$ 6.9
Legal reserves	3.2	4.5	-		1.8	(c)	5.9
Environmental reserves	0.3	-	-		-		0.3
Uncertain tax positions	13.4	1.2	-		10.0	(d)	4.6
Year Ended December 31, 2004							
Allowance for uncollectible accounts	$ 8.5	$ 5.4	$ 2.8	(a)	$ 10.3	(b)	$ 6.4
Legal reserves	4.0	1.4	-		2.2	(c)	3.2
Environmental reserves	1.8	-	-		1.5	(e)	0.3
Uncertain tax positions	16.8	3.2	-		6.6	(d)	13.4

(a) Recoveries. Charged to other accounts for the year ended December 31, 2006 and 2005, respectively, includes the establishment of an allowance of $1.5 million and $1.6 million.

(b) Uncollectible accounts charged off. Deductions for the year ended December 31, 2004, includes a charge off of $1.4 million by Worry Free.

(c) Payment of claims.

(d) Reversal of uncertain tax positions. Deductions for the year ended December 31, 2005, includes a reclass of $0.8 million to franchise taxes payable.

(e) Reversal of reserve for remediation of soil and groundwater.

Kansas City Power & Light Company
Valuation and Qualifying Accounts
Years Ended December 31, 2006, 2005 and 2004

Description	Balance At Beginning Of Period	Additions: Charged To Costs And Expenses	Additions: Charged To Other Accounts		Deductions		Balance At End Of Period
Year Ended December 31, 2006			(millions)				
Allowance for uncollectible accounts	$ 2.6	$ 4.5	$ 4.4	(a)	$ 7.3	(b)	$ 4.2
Legal reserves	4.5	2.8	-		3.4	(c)	3.9
Environmental reserves	0.3	-	-		-		0.3
Uncertain tax positions	1.2	0.8	-		0.2	(d)	1.8
Year Ended December 31, 2005							
Allowance for uncollectible accounts	$ 1.7	$ 3.3	$ 4.6	(a)	$ 7.0	(b)	$ 2.6
Legal reserves	3.2	3.1	-		1.8	(c)	4.5
Environmental reserves	0.3	-	-		-		0.3
Uncertain tax positions	3.7	0.3	-		2.8	(d)	1.2
Year Ended December 31, 2004							
Allowance for uncollectible accounts	$ 4.9	$ 2.6	$ 2.7	(a)	$ 8.5	(b)	$ 1.7
Legal reserves	3.8	1.4	-		2.0	(c)	3.2
Environmental reserves	1.8	-	-		1.5	(e)	0.3
Uncertain tax positions	6.4	2.1	-		4.8	(d)	3.7

(a) Recoveries. Charged to other accounts for the year ended December 31, 2006 and 2005, respectively, includes the establishment of an allowance of $1.5 million and $1.6 million.

(b) Uncollectible accounts charged off. Deductions for the year ended December 31, 2004, includes a charge off of $1.4 million by Worry Free.

(c) Payment of claims.

(d) Reversal of uncertain tax positions. Deductions for the year ended December 31, 2005, includes a reclass of $0.8 million to franchise taxes payable.

(e) Reversal of reserve for remediation of soil and groundwater.

SIGNATURES

Pursuant to the requirements of Section 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.

GREAT PLAINS ENERGY INCORPORATED

Date: February 27, 2007

By: /s/Michael J. Chesser
Michael J. Chesser
Chairman of the Board and
Chief Executive Officer

Pursuant to the requirements of the Securities 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/Michael J. Chesser Michael J. Chesser	Chairman of the Board and Chief Executive Officer (Principal Executive Officer)	
/s/Terry Bassham Terry Bassham	Executive Vice President – Finance and Strategic Development and Chief Financial Officer (Principal Financial Officer)	
/s/Lori A. Wright Lori A. Wright	Controller (Principal Accounting Officer)	
David L. Bodde*	Director	February 27, 2007
/s/William H. Downey William H. Downey	Director	
Mark A. Ernst*	Director	
Randall C. Ferguson, Jr.*	Director	
William K. Hall*	Director	
Luis A. Jimenez*	Director	
James A. Mitchell*	Director	
William C. Nelson*	Director	
Linda H. Talbott*	Director	
Robert H. West*	Director	

*By /s/Michael J. Chesser
Michael J. Chesser
Attorney-in-Fact*

SIGNATURES

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

KANSAS CITY POWER & LIGHT COMPANY

Date: February 27, 2007

By: /s/ William H. Downey
William H. Downey
President and Chief Executive Officer

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

Signature	Title	Date
/s/ William H. Downey William H. Downey	President and Chief Executive Officer and Director (Principal Executive Officer)	
/s/Terry Bassham Terry Bassham	Chief Financial Officer (Principal Financial Officer)	
/s/Lori A. Wright Lori A. Wright	Controller (Principal Accounting Officer)	
David L. Bodde*	Director	February 27, 2007
/s/Michael J. Chesser Michael J. Chesser	Chairman of the Board	
Mark A. Ernst*	Director	
Randall C. Ferguson, Jr.*	Director	
Luis A. Jimenez*	Director	
James A. Mitchell*	Director	
William C. Nelson*	Director	
Linda H. Talbott*	Director	

*By /s/Michael J. Chesser
Michael J. Chesser
Attorney-in-Fact*

2006 Annual Report

Kansas Electric Power Cooperative, Inc.

The Power of Human Connections

2006 KEPCo Annual Report

Contents

Employees

Stephen Parr ..... Executive Vice President & Chief Executive Officer

Tom Grennan ..... Senior Vice President & Chief Operating Officer

Bob Bowser ..... Vice President of Regulatory & Technical Services

Les Evans ..... Vice President of Power Supply

J. Michael Peters ..... Vice President of Administration & General Counsel

Coleen Wells ..... Vice President of Finance & Controller

Laura Armstrong ..... Administrative Assistant

Mark Barbee ..... Manager of Engineering, KSI Vice President of Engineering

Sam Delap ..... Information System Specialist

Terry Deutscher ..... Sr. SCADA/Metering Technician - Ellsworth

Carol Killingsworth ..... Operations Analyst

Shari Koch ..... Accounting, Payroll & Benefits Specialist

Elizabeth Lesline ..... Administrative Assistant/Receptionist

Mitch Long ..... Sr. SCADA/Metering Technician - Topeka

Loren Medley ..... Business Development Coordinator

Michael Morris ..... SCADA/Metering Technician - Wichita

Erika Old ..... Finance & Benefits Analyst 2

Matt Ottman ..... Engineer 2

John Payne ..... Senior Engineer

Robert Peterson ..... Sr. Engineering Technician

Rita Petty ..... Executive Assistant & Manager of Office Services

Paul Stone ..... System Operator

Phil Wages ..... Director of Member Services & External Affairs

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 625 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.
P.O. Box 4877 Topeka, KS 66604
600 SW Corporate View Topeka, KS 66615
(785) 273-7010 www.kepco.org

A Touchstone Energy® Cooperative

2006 Message

Mr. Parr and Mr. Maginley

from

Kenneth J. Maginley
KEPCo President

Stephen E. Parr,
Executive Vice President
& Chief Executive Officer

Reflection, by definition, is the activity of a person to consider and evaluate past experiences and events and the impact they will have on the future. The strategic business decisions made in 2006 will likely be reflected upon for many years to come, as it was a year that focused on the stabilizing and strengthening of KEPCo's long-term power supply resources needed to serve its Member Distribution Cooperatives and their Consumer-Owners.

After enduring the past few years, KEPCo realized that the practice of using short-term purchase power agreements, relying on increasing amounts of natural gas-fired generation, and purchasing power priced by the spot markets are no longer prudent business plans. Energy markets and natural gas have proven to be volatile, unpredictable and very high cost. As such, utilities across the country are reducing their vulnerability to short-term markets by building additional generation and are actively pursuing resources with fuels, such as coal, that offset exposure to natural gas generation.

However, the utility industry is entering a time of political and environmental concern surrounding global warming and climate change. Heightened pressure has been levied against the utility industry to reduce emissions from coal-fired generating units. Speculation has risen that coal-fired generation may face certain taxes and externality costs that could make the resource uneconomical. If low-cost coal generation is excised out of future resource options, the economic consequences will be substantial, an outcome that policymakers, both on state and federal levels, need to acknowledge.

KEPCo is proud of the fact that nearly fifty percent of its energy resource mix, nuclear and hydroelectric, do not emit any greenhouse gases. This statement likely can not be made by any utility east of the Rockies. KEPCo was an environmentally-conscious utility long before global warming became a national issue and we fully intend to continue to be one.

In keeping with emission reduction, KEPCo realizes that one of the simplest ways to reduce emissions is to reduce energy consumption. KEPCo has embraced the increased interest in energy efficiency and conservation by revamping one of its long-standing programs into one that rewards choosing energy efficient, electric heating

and cooling systems. This program not only benefits KEPCo and its Members, but the Owner-Consumers and the environment as well.

Fundamental to KEPCo's longevity and continued viability was the extension of the Wholesale Power Contracts between KEPCo and its Members to 2045. The extension illustrates the confidence of its Member Electric Cooperatives in KEPCo's ability to meet the Membership's energy needs and requirements in an economical manner for decades to come.

Recognizing the need to own additional base load generation, and central to KEPCo's transition, was the commitment made by KEPCo and its Board of Trustees to acquire a 30 MW ownership participation in Iatan 2, an 850 MW high efficiency coal-fired power plant, with state-of-the-art environmental controls. Iatan 2 is under construction at Kansas City Power & Light's existing Iatan Generating Station site in Platte County, MO, and has a projected in-service date of 2010. Even though uncertainty exists about possible added taxes or costs associated with coal-fired generation, this decision is a key component in KEPCo providing its Members with economical and reliable generation and mitigating future exposure to volatile and high-priced electric markets and natural gas prices.

Given the energy markets as they are today, securing an economical and reliable power supply is of paramount importance. As part of KEPCo's focus on long-term resources, KEPCo negotiated a new purchase power agreement to 2018 with Sunflower Electric Power Corporation. The agreement will provide for approximately ten percent of KEPCo's power requirements.

2006-07 KEPCo Executive Committee (seated): Harlow Haney; Melroy Kopsa; Robert Reece; (standing) Stephen Parr, Executive Vice President & CEO, Kenneth Maginley, President; Kirk Thompson Vice President; Bryan Coover, Treasurer; and Gordon Coulter, Secretary.

In addition, KEPCo continued to develop its long-standing partnership with Westar through negotiations of a new long-term purchase power agreement. KEPCo's valuable relationship with Westar is a key component of KEPCo's power supply for its Members. This new contract, anticipated to be completed in early 2007, will solidify KEPCo's resource mix by allowing access to numerous generating units and will continue for the same time period as the extended Wholesale Power Contracts with KEPCo's Members.

KEPCo's ongoing success is made possible by the continued support and diligent efforts of KEPCo's Members, Board of Trustees and the dedication of a highly skilled staff. All of their efforts are appreciated and applauded. Several of Staff's accomplishments are detailed in this annual report.

The passage of time is marked by milestones and events that are recalled for generations. The decision to create KEPCo and to participate in the ownership of Wolf Creek, and the events leading to those decisions, can be recalled today as if they happened yesterday. As KEPCo continues on its transitional path, the business decisions of 2006 may well evoke the same recollection for years to come. Future business decisions for KEPCo will be based on thoughtful plans and sound business principles, which will enable KEPCo to provide a long-term, reliable and economical electric supply for its Members and for rural Kansas.

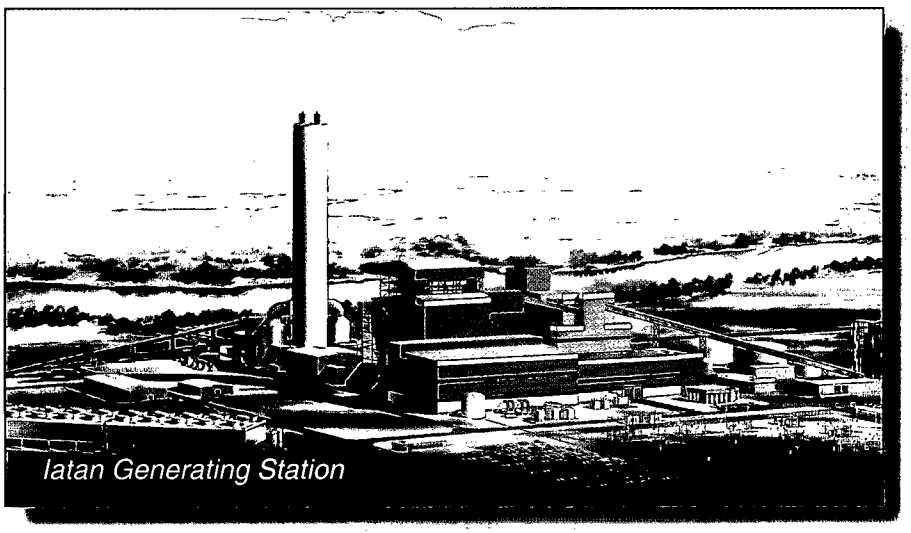
Kenneth J. Maginley

Stephen E. Parr

2006 KEPCo Highlights

KEPCo completed efforts to extend Member contracts to 2045 which provides the basis and security needed for future resource acquisitions.

In May, KEPCo executed documents to acquire a 30 MW ownership participation in Iatan 2, an 850 MW high-efficiency, coal-fired power plant, with state-of-the-art environmental controls. Iatan 2 is to be constructed by KCP&L at the existing Iatan Generating Station site in Platte County, MO.


Iatan Generating Station

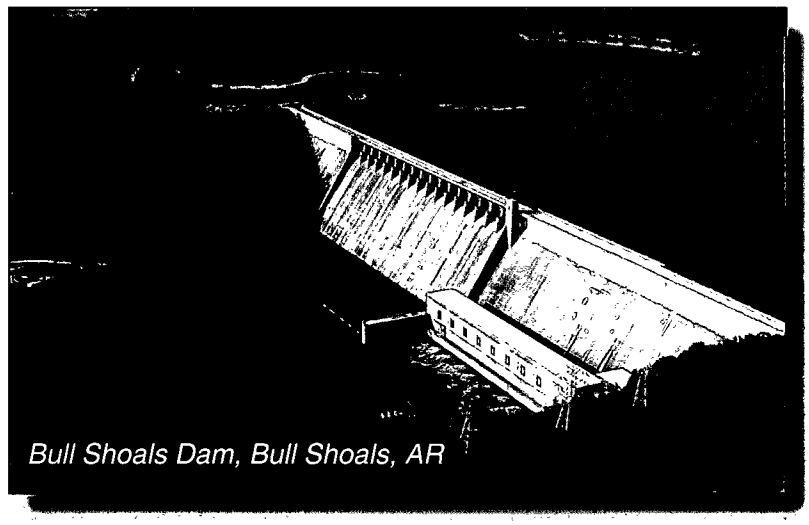
KEPCo completed a credit facility with CFC that allows KEPCo to fund the Iatan 2 project, including long-term, permanent financing, if required.

KEPCo negotiated a new long-term power supply agreement through 2018 with Sunflower Electric Cooperative which supplies approximately ten percent of KEPCo's energy requirements.

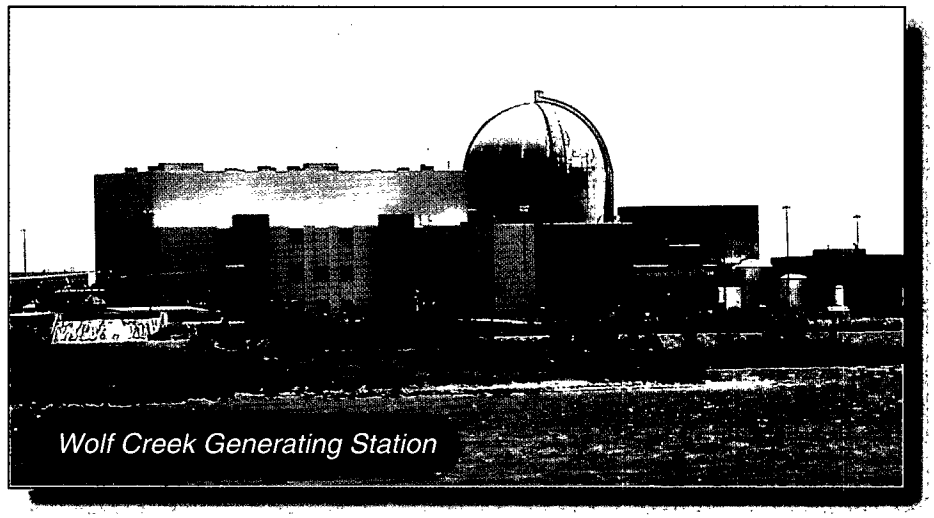
KEPCo finalized a three-year extension of its power supply contract with Southwestern Power Administration (SWPA), thru May 31, 2016.

KEPCo executed documents to acquire a 30 MW ownership participation in Iatan 2, an 850 MW high-efficiency, coal-fired power plant

KEPCo participated in SWPA's 2006 energy deferral program to mitigate the severe drought conditions experienced in the region. Through this effort, KEPCo was able to continue to meet its Member power supply obligations with low-cost SWPA hydropower.

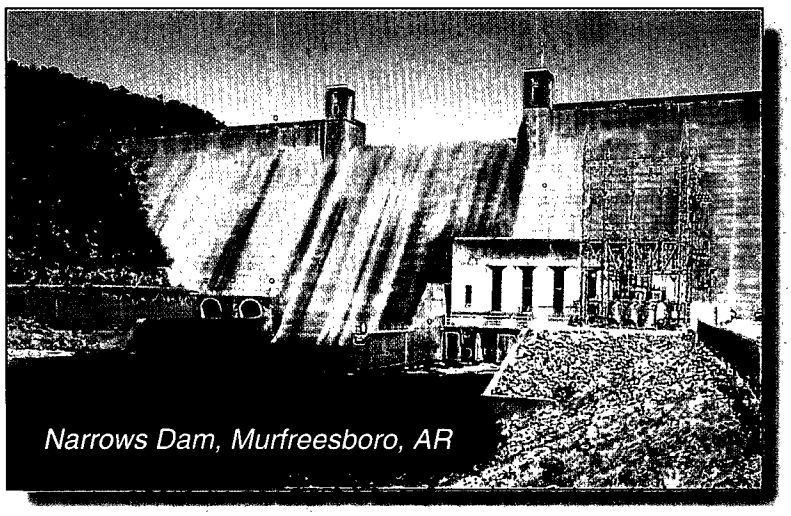

Bull Shoals Dam, Bull Shoals, AR

Wolf Creek Generating Station established a record-setting 506 days of continuous operation which culminated this fall with Refuel 15. The Refuel 15 outage was conducted in a record-setting 34 days.


Wolf Creek Generating Station

KEPCo continued to actively participate in the Southwest Power Pool (SPP) as the SPP progresses to develop as the regional transmission organization (RTO) in this area.

KEPCo assisted Members with customer parallel generation issues including the development of standardized customer parallel generation interconnection materials and holding workshops for Members.


Narrows Dam, Murfreesboro, AR

KEPCo's Long Range Resource Plan was updated. The update provides a strategic direction for KEPCo's power supply requirements for the next several years.

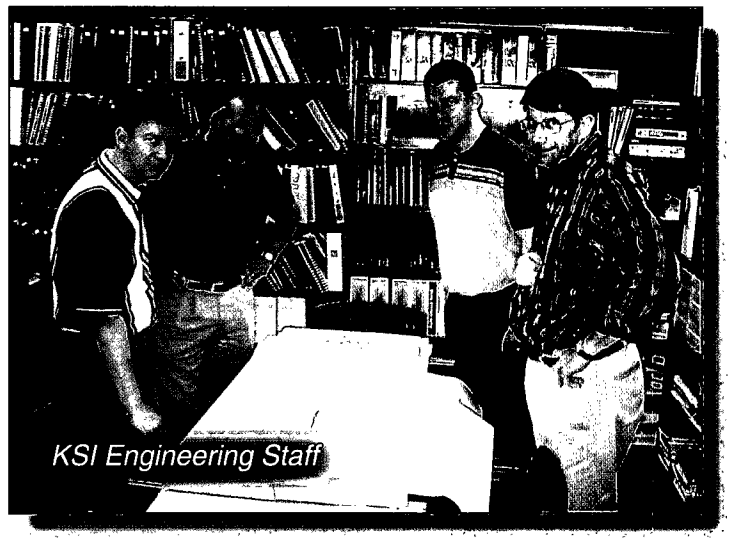
The KEPCo Board of Trustees completed a two-day Strategic Planning Retreat in 2006. Developed from the retreat was a new Strategic Plan to guide KEPCo's business and power supply decisions in the future.

Wolf Creek Generating Station established a record-setting 506 days of continuous operation

KEPCo's Sharpe Generating Station was available for peaking capacity the entire year and continues to be a valuable resource to KEPCo in addition to providing emergency back-up service for the Wolf Creek plant.

KEPCo Services, Inc. (KSI) recorded its ninth successful year of operation in 2006. KSI Engineering, the principal operating activity of KSI, is listed as the official engineering consultant by ten Electric Cooperatives. In 2006, KSI completed numerous challenging projects, including line staking for Members affected by damaging storms.

Continued on page 12


KSI Engineering Staff

KEPCo Member Cooperatives Trustees, Alternates and Managers


Dwight Engelland

Ark Valley Electric Cooperative Assn., Inc.
PO Box 1246, 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 M. 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 D. Compton
Manager -- Rodney V. Gerdes


Kevin Compton


Rod Gerdes


Richard Pearson

Butler Rural Electric Cooperative Assn., Inc.
PO Box 1242, El Dorado, KS 67042 316-321-9600
Trustee Rep. -- Richard Pearson
Alternate Trustee Rep. -- Dale Short
Manager -- Dale Short


Dale Short


Dwane Kessinger

Caney Valley Electric Cooperative Assn., Inc.
PO Box 308, Cedar Vale, KS 67024 620-758-2262
Trustee Rep. -- Dwane Kessinger
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 L. Haney
Alternate Trustee Rep. -- Donald E. Hellwig
Manager -- Donald E. 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 H. 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


Larry Stevens

Leavenworth-Jefferson Electric Cooperative, Inc.
PO Box 70, McLouth, KS 66054 913-796-6111
Trustee Rep. -- Larry H. Stevens
Alternate Trustee Rep. -- H.B. Canida
Manager -- H.B. Canida


H.B Canida


Scott Whittington

Lyon-Coffey Electric Cooperative, Inc.
PO Box 229, Burlington, KS 66839 620-364-2116
Trustee Rep. -- Scott Whittington
Alternate Trustee Rep. -- Donna Williams
Manager -- Scott Whittington


Donna Williams

KEPCo Member Cooperatives Trustees, Alternates and Managers


Gordon Coulter

Ninnescah Electric Cooperative Assn., Inc.
PO Box 967, Pratt, KS 67124 620-672-5538
Trustee Rep. -- Gordon Coulter
Alternate Trustee Rep. -- Carla A. Bickel
Manager -- Carla A. 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

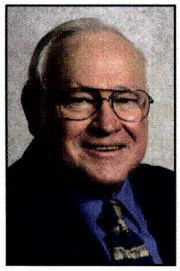

Leon Eck


Doug Jackson

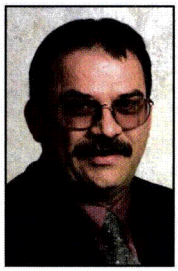

David Reichenberger

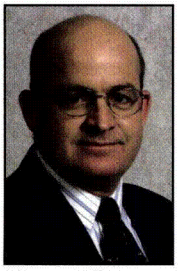
Sedgwick County Electric Cooperative Assn., Inc.
PO Box 220, Cheney, KS 67025 316-542-3131
Trustee Rep. -- David Reichenberger
Alternate Trustee Rep. -- Alan L. Henning
Manager -- Alan L. Henning


Alan Henning

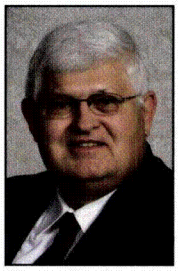

Charles Riggs

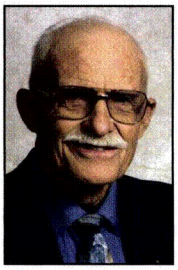
Sumner-Cowley Electric Cooperative, Inc.
PO Box 220, Wellington, KS 67152 620-326-3356
Trustee Rep. -- Charles Riggs
Alternate Trustee Rep. -- Cletas Rains
Manager -- Cletas Rains


Cletas Rains

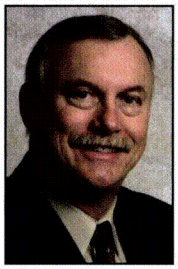

Bryan Coover

Twin Valley Electric Cooperative, Inc.
PO Box 385, Altamont, KS 67330 620-784-5500
Trustee Rep. -- Bryan W. Coover
Alternate Trustee Rep. -- Ron Holsteen
Manager -- Ron Holsteen

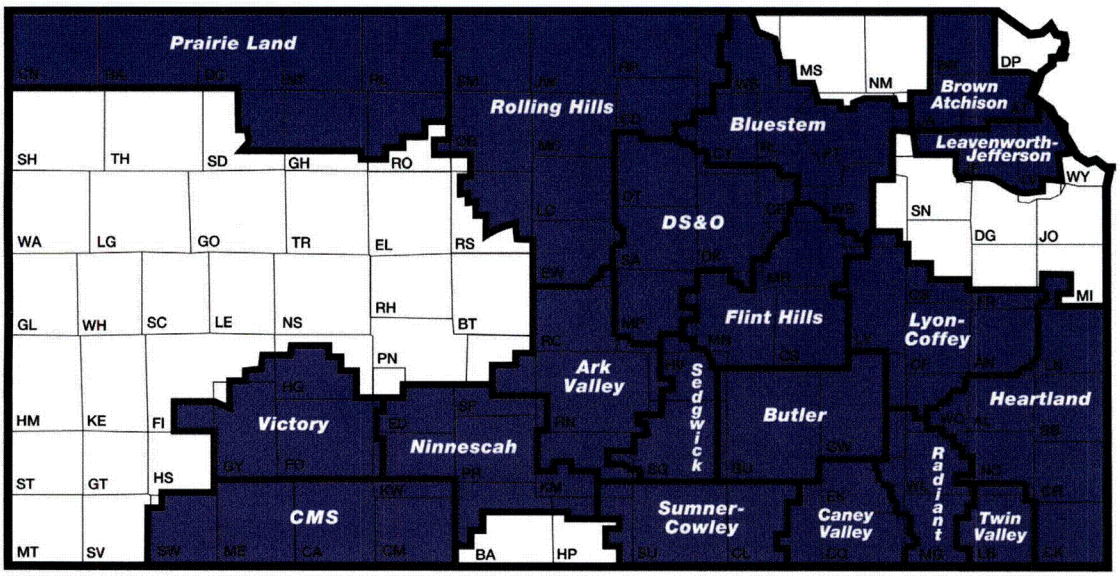

Ron Holsteen


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

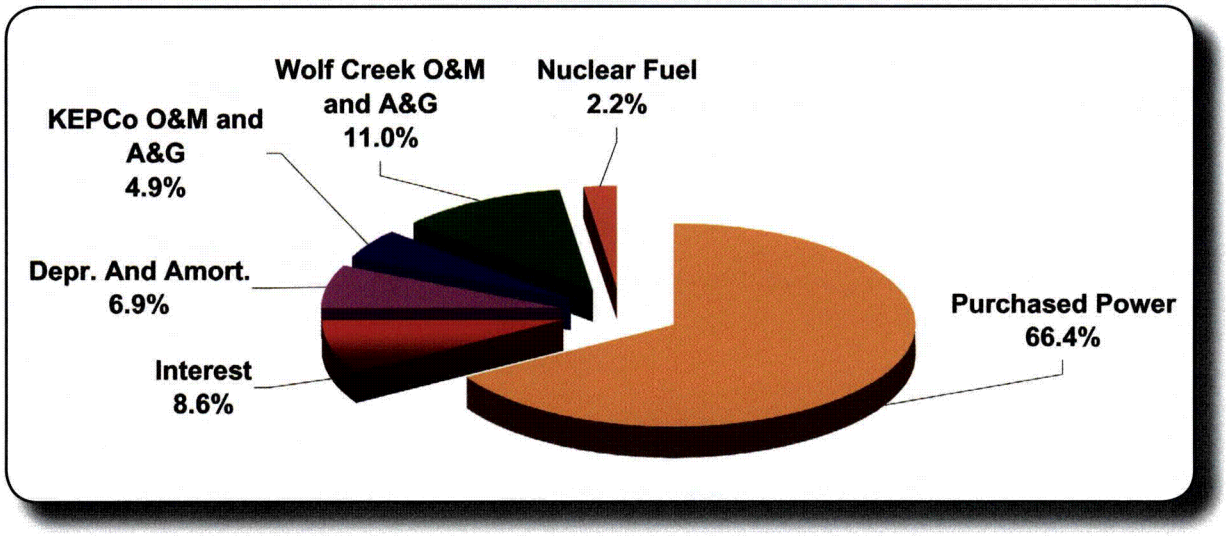

Terry Janson

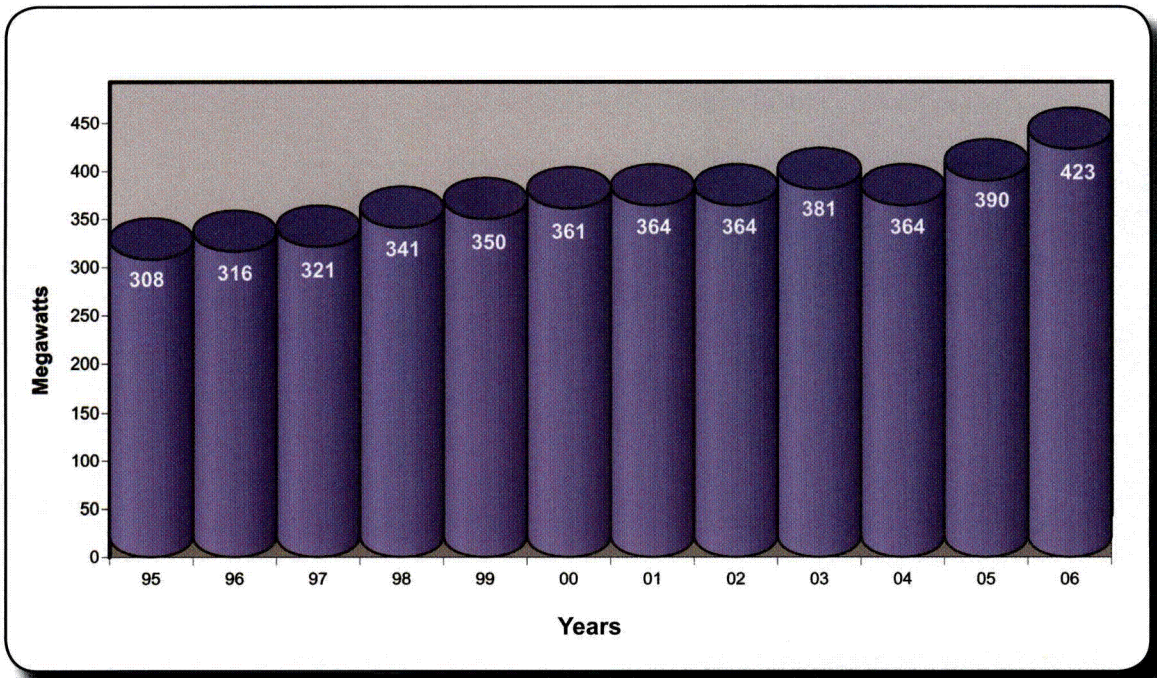
KEPCo Member Area Map



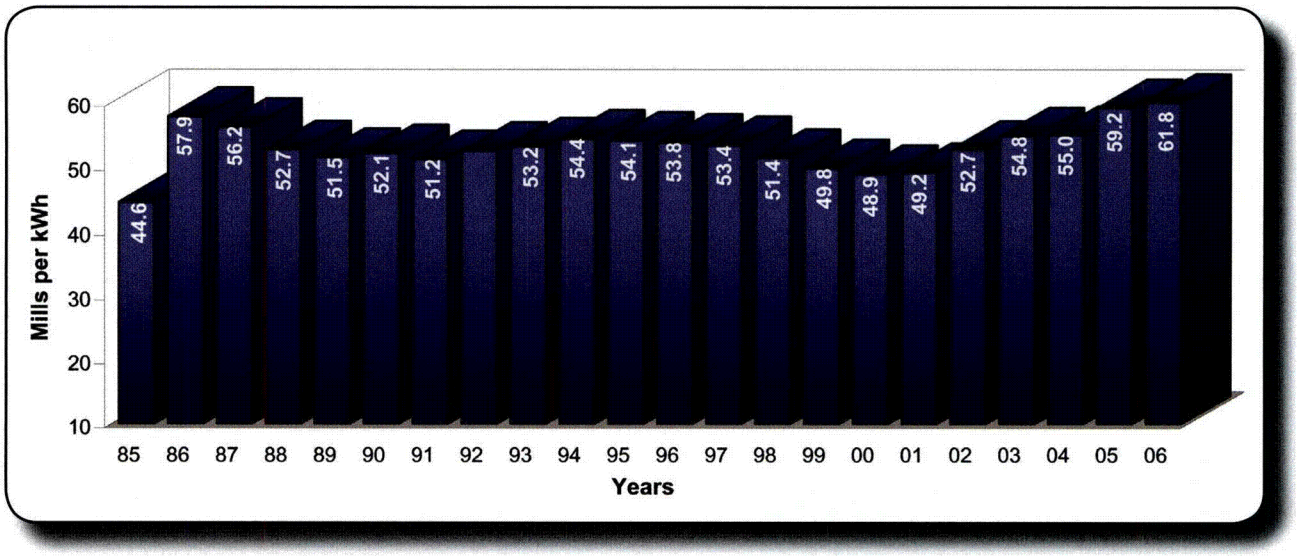
Operating Statistics

Operating Expenses



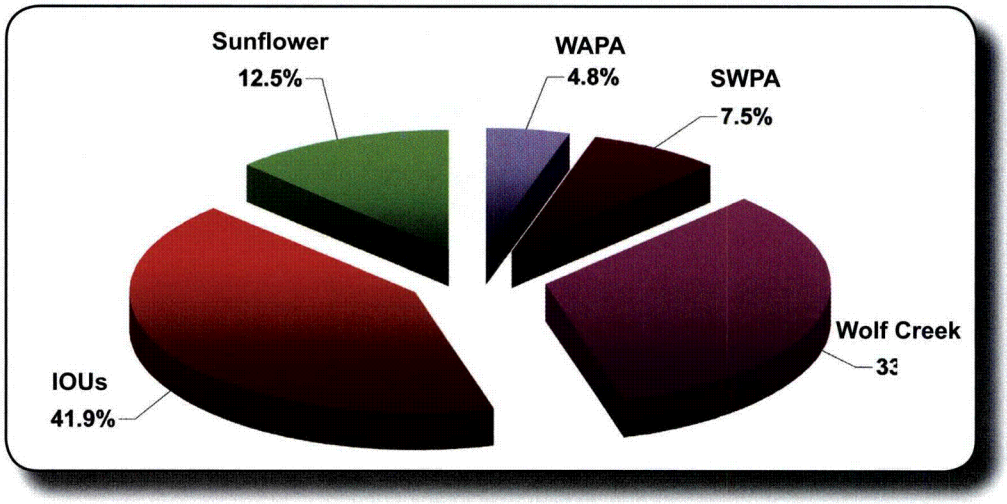


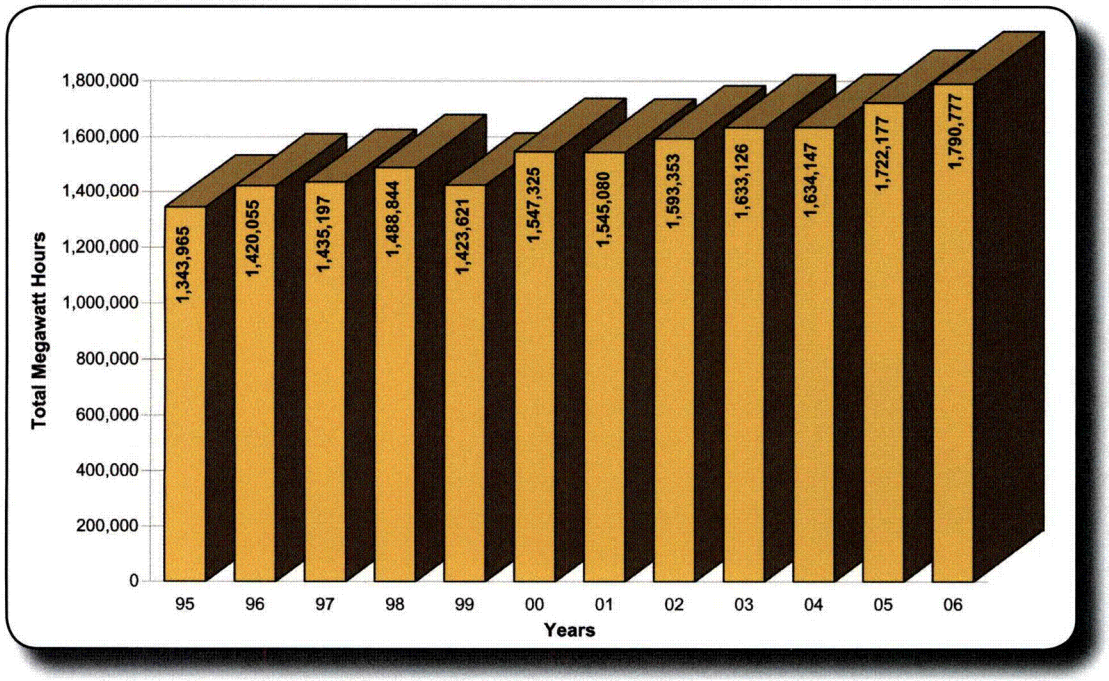
Peak Demand



Rates

Sources of Energy



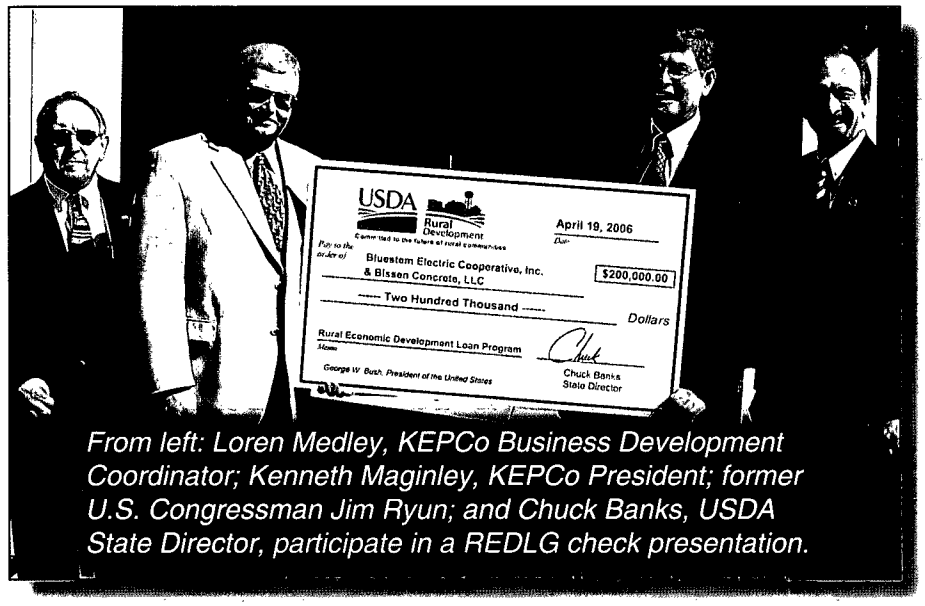


Energy Sales

2006 KEPCo Highlights

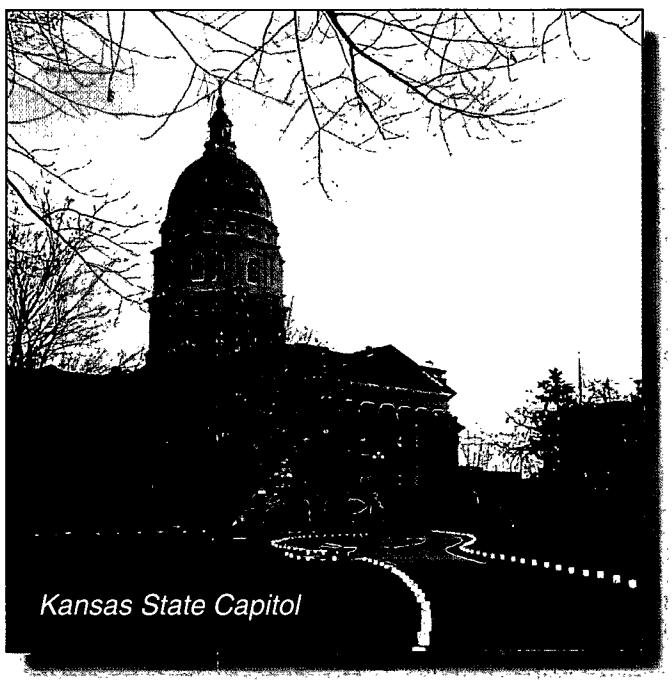
Continued from page 5

KEPCo continued to support Members in their successful participation in USDA's Rural Economic Development Loan and Grant (REDLG) program. In 2006, five Members garnered $2,196,000 in zero interest loans for a variety of economic development projects. An additional $2,247,102 was invested by the projects as supplemental funds for a total of $4,443,102 invested capital and the creation of 72 new rural area jobs in Kansas.



From left: Loren Medley, KEPCo Business Development Coordinator; Kenneth Maginley, KEPCo President; former U.S. Congressman Jim Ryun; and Chuck Banks, USDA State Director, participate in a REDLG check presentation.

KEPCo continues to work with KEC and Sunflower on legislative issues important to Kansas Cooperatives in Kansas and in Washington, D.C. KEPCo testified on several pieces of Kansas legislation in 2006 and tracked numerous other bills. KEPCo also participated in the NRECA Legislative Conference and supported a series of actions in response to NRECA calls for assistance on Federal legislation.



Kansas State Capitol

KEPCo continues to support Member marketing efforts by serving as a key contact for Touchstone Energy programs in Kansas, developing advertisements, helping with Member annual meetings and assisting on numerous individual Member projects.

KEPCo continued to fund and assist Members in promotion of an energy efficiency program targeted at electric water heaters and heating systems. KEPCo supports the efficient use of electricity and this program helps communicate that message.

KEPCo's support in economic development led to $4,443,102 invested capital and the creation of 72 new rural Kansas jobs during 2006

Independent Accountants' Report

Board of Trustees
Kansas Electric Power Cooperative, Inc.
Topeka, Kansas

We have audited the accompanying consolidated balance sheet of Kansas Electric Power Cooperative, Inc. (the Cooperative) as of December 31, 2006, and the related consolidated statements of margin, patronage capital and cash flows for the year then ended. These financial statements are the responsibility of the Cooperative's management. Our responsibility is to express an opinion on these financial statements based on our audit. The financial statements of the Cooperative as of and for the year ended December 31, 2005, were audited by other accountants, whose report dated April 7, 2006, on those statements was qualified because certain depreciation and amortization methods used do not conform to accounting principles generally accepted in the United States of America as discussed in the notes.

We conducted our audit 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 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 audit provides a reasonable basis for our opinion.

As explained in *Note 3*, certain depreciation and amortization methods have been used in the preparation of the 2006 financial statements which, in our opinion, are not in accordance with accounting principles generally accepted in the United States of America. The effects on the financial statements of the aforementioned departure are explained in *Note 3*.

In our opinion, except for the effects of using the aforementioned depreciation and amortization methods as discussed in *Note 3*, the 2006 consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Cooperative as of December 31, 2006, and the results of its operations and its cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America.

In accordance with *Government Auditing Standards*, we also have issued our report dated April 5, 2007, on our consideration of the Cooperative's internal control over financial reporting and our tests of its compliance with certain provisions of laws, regulations, contracts 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.

BKD LLP

April 5, 2007

6120 South Yale Avenue, Suite 1400 Tulsa, OK 74136-4223 918 584-2900 Fax 918 584-2931

Consolidated Balance Sheets

December 31, 2006 and 2005

Assets	2006	2005
Utility Plant		
In-service	$ 225,003,755	$ 223,862,852
Less allowances for depreciation	(120,837,298)	(117,754,899)
Net in-service	104,166,457	106,107,953
Construction work in progress	6,550,342	2,278,799
Nuclear fuel, less accumulated amortization of $12,921,304 and $14,188,165 for 2006 and 2005, respectively	4,921,775	3,491,532
Total utility plant	115,638,574	111,878,284
Restricted Assets		
Investments in the National Rural Utilities Cooperative Finance Corporation	3,219,847	3,249,686
Bond fund reserve	4,295,806	4,262,478
Decommissioning fund	9,245,665	7,953,404
Investments in other associated organizations	152,306	142,514
Total restricted assets	16,913,624	15,608,082
Current Assets		
Cash and cash equivalents	3,271,471	5,345,163
Member accounts receivable	8,021,333	8,658,516
Materials and supplies inventory	2,983,476	2,827,387
Other assets and prepaid expenses	653,037	811,015
Total current assets	14,929,317	17,642,081
Other Long-term Assets		
Deferred charges		
Wolf Creek disallowed costs (less accumulated amortization of $11,120,734 and $10,363,570 for 2006 and 2005, respectively)	14,862,187	15,619,350
Wolf Creek deferred plants costs (less accumulated amortization of $15,649,598 and $12,519,678 for 2006 and 2005, respectively)	31,299,195	34,429,115
Wolf Creek decommissioning regulatory asset	4,114,385	3,159,210
Deferred Department of Energy decommissioning costs	74,712	167,915
Deferred incremental outage costs	3,535,349	2,015,086
Other deferred charges (less accumulated amortization of $6,106,253 and $5,405,117 for 2006 and 2005, respectively)	3,597,661	4,298,796
Unamortized debt issuance costs	855,402	980,834
Other investments	248,686	210,958
Total long-term assets	58,587,577	60,881,264
Total assets	$ 206,069,092	$ 206,009,711

Consolidated Balance Sheets

December 31, 2006 and 2005

Liabilities and Patronage Capital	2006	2005
Patronage Capital		
Memberships	$ 3,200	$ 3,200
Patronage capital	19,497,487	18,450,805
Total patronage capital	19,500,687	18,454,005
Long-term Debt	142,272,490	149,908,644
Other Long-term Liabilities		
Wolf Creek decommissioning liability	16,332,466	13,916,214
Wolf Creek nuclear operating liabilities	2,589,872	2,443,767
Arbitrage rebate long-term liability	537,765	992,862
Other deferred credits	12,452	100,213
Total other long-term liabilities	19,472,555	17,453,056
Current Liabilities		
Current maturities of long-term debt	11,162,495	10,464,348
Line of credit	3,521,028	—
Accounts payable	7,958,739	7,750,203
Payroll and payroll-related liabilities	284,661	263,690
Accrued property taxes	1,319,875	1,294,342
Accrued interest payable	576,562	421,423
Total current liabilities	24,823,360	20,194,006
Total patronage capital and liabilities	$ 206,069,092	$ 206,009,711

See accompanying notes to consolidated financial statements.

Statements of Revenue and Expenses

December 31, 2006 and 2005

	2006	2005
Operating Revenues		
Sales of electric energy	$ 110,707,844	$ 101,933,017
Other	64,089	318,689
Total operating revenues	110,771,933	102,251,706
Operating Expenses		
Power purchased	73,351,849	63,050,719
Nuclear fuel	2,382,257	2,281,038
Plant operations	9,072,478	8,731,121
Plant maintenance	3,062,210	2,974,581
Administrative and general	5,069,698	4,901,614
Amortization of deferred charges	4,588,219	5,142,698
Depreciation and decommissioning	4,168,565	4,362,753
Total operating expenses	101,695,276	91,444,524
Net operating revenues	9,076,657	10,807,182
Interest and Other Deductions		
Interest on long-term debt	8,540,243	8,836,180
Amortization of debt issuance costs	125,431	129,895
Other deductions	172,704	67,315
Total interest and other deductions	8,838,378	9,033,390
Operating Income	238,279	1,773,792
Other Income (Expense)		
Interest income	875,646	853,209
Other income (expense)	(67,243)	824,856
Total other income	808,403	1,678,065
Net margin	$ 1,046,682	$ 3,451,857

See accompanying notes to consolidated financial statements.

Statements of Changes in Patronage Capital

December 31, 2006 and 2005

	Memberships	Patronage Capital	Total
Balance, December 31, 2004	$ 3,200	$ 14,998,948	$ 15,002,148
Net margin	—	3,451,857	3,451,857
Balance, December 31, 2005	3,200	18,450,805	18,454,005
Net margin	—	1,046,682	1,046,682
Balance, December 31, 2006	$ 3,200	$ 19,497,487	$ 19,500,687

Statements of Cash Flows

December 31, 2006 and 2005

	2006	2005
Operating Activities		
Net margins	$ 1,046,682	$ 3,451,857
Adjustments to reconcile net margin to net cash provided by operating activities		
Depreciation and amortization	3,704,711	3,911,449
Decommissioning	1,458,328	451,304
Amortization of nuclear fuel	1,748,780	1,681,987
Amortization of deferred charges	4,588,218	4,045,720
Amortization of deferred incremental outage costs	2,557,796	3,470,606
Amortization of debt issuance costs	125,432	129,895
Changes in		
Member accounts receivable	637,183	(1,326,340)
Materials and supplies	(156,089)	(42,261)
Other assets and prepaid expenses	120,250	(202,794)
Accounts payable	208,536	284,122
Payroll and payroll-related liabilities	20,971	(2,444)
Accrued property tax	25,533	(16,441)
Accrued interest payable	155,139	51,333
Restricted assets	(33,328)	(49,836)
Other long-term liabilities	(300,801)	249,471
Net cash provided by operating activities	15,907,341	16,087,628
Cash Flows From Investing Activities		
Additions to electric plant	(6,034,758)	(1,469,394)
Additions to nuclear fuel	(3,179,023)	(615,088)
Additions to deferred incremental outage costs	(4,078,059)	(3,556,885)
Investments in decommissioning fund assets	(1,292,261)	(451,304)
Other	20,047	—
Net cash used in investing activities	(14,564,054)	(6,092,671)
Cash Flows From Financing Activities		
Net borrowing under line of credit agreement	3,521,028	—
Principle payments on long-term debt	(10,464,348)	(9,907,800)
Increase in debt issuance costs related to debt refinancing	—	(670,489)
Utilization of RUS cushion of credit	3,526,341	698,771
Net cash used in financing activities	(3,416,979)	(9,879,518)
Net increase (decrease) in cash and cash equivalents	(2,073,692)	115,439
Cash and Cash Equivalents, Beginning of Year	5,345,163	5,229,724
Cash and Cash Equivalents, End of Year	$ 3,271,471	$ 5,345,163
Supplemental Cash Flows Information		
Cash paid during the year for interest	$ 8,385,104	$ 8,852,162

See accompanying notes to consolidated financial statements.

Note 1: Nature of Operations and Summary of Significant Accounting Policies

Nature of Operations

Kansas Electric Power Cooperative, Inc. and its subsidiary (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.

System of Accounts

KEPCo maintains its accounting records substantially in accordance with the Rural Utilities Service (RUS) Uniform Systems of Accounts and in accordance with accounting practices prescribed by the KCC.

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. KEPCo's rates include an energy cost adjustment (ECA) mechanism, which allows KEPCo to pass along increases in certain energy costs to its cooperative members.

Principles of Consolidation

The consolidated financial statements include the amounts of the Cooperative and its majority-owned subsidiary, KEPCo Services, Inc. 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.

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.

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, 2006 and 2005, was 2.98% and 2.98%, 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 years
Office furniture and fixtures	10 to 20 years
Leasehold improvements	20 years
Transmission equipment	10 years

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.

Decommissioning Fund Assets/Decommissioning Liability

As of December 31, 2006 and 2005, approximately $9.2 million and $8 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 Nuclear Generating Station (Wolf Creek). The trustee invests the decommissioning funds primarily in mutual finds, 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 2006, the KCC approved a 2005 decommissioning cost study, which increased the estimate of total decommissioning costs to $517.6 million in 2005 dollars ($31.1 million is KEPCo's share). The study assumes a 4.4% rate of inflation and 7% rate of return.

KEPCo adopted the Statement of Financial Accounting Standard (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 initially recognized an asset retirement obligation of $11.7 million; utility plant in-service, net of accumulated depreciation, was increased by $2.9 million; and 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 refunded.

The decommissioning study in 2005 increased the asset retirement obligation by approximately $1.5 million, utility plant in-service, net of accumulated depreciation by $.2 million and the regulatory asset by $1.2 million in 2006.

A reconciliation of the asset retirement obligation for the years ended December 31, 2006 and 2005 is as follows:

	2006	2005
Balance at January 1	$ 13,916,214	$ 13,128,504
Accretion	938,420	787,710
Increase from 2005 study	1,477,832	—
Balance at December 31	$ 16,332,466	$ 13,916,214

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, and will be collected from members in future electric rates.

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. Cash equivalents consist primarily of certificates of deposit.

Accounts Receivable

Accounts receivable are stated at the amount billed to members and customers. The Cooperative provides allowances for doubtful accounts, which is based upon a review of outstanding receivables, historical collection information and existing economic conditions.

Materials and Supplies Inventory

Materials and supplies inventory are valued at average cost.

Unamortized Debt Issuance 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.

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.

	2006	2005
Cash surrender value of contracts	$ 4,693,922	$ 4,383,449
Borrowings against contracts	(4,693,922)	(4,383,449)
	$ 0	$ 0

Borrowings against contracts include a prepaid interest charge. KEPCo pays interest on these borrowings at a rate of 4.27% and 5.45% for the years ended December 31, 2006 and 2005, respectively.

Revenues

Revenues are recognized during the month the electricity is sold. 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.

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.

Reclassifications

Certain reclassifications have been made to the 2005 financial statements to conform to the 2006 financial statement presentation. These reclassifications had no effect on net earnings.

Note 2: 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 KPECo'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 that could be recovered in such an environment cannot be predicted.

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. 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 that would be unfavorable to KEPCo to be adopted within the next 12 months.

Note 3: 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 7, 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 7, 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 revenues and expenses. Investment gains related to the decommissioning fund are recorded as a reduction to the regulatory asset. KEPCo recorded gains of $0.9 million and $0.8 million in 2006 and 2005, respectively.

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:

		2006		2005
Deferred charges	$	35,636,341	$	39,199,975
Patronage capital		35,636,341		39,199,975
Net margin		(3,563,634)		(3,563,634)

Note 4: Wolf Creek Nuclear Operating Corporation (WCNOC)

KEPCo owns 6% of WCNOC, 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 WCNOC is consolidated on a pro rata basis. Substantially all of KEPCo's utility plant consists of its pro rata share of WCNOC. KEPCo is entitled to a proportionate share of the capacity and energy from WCNOC, which is used to supplement 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 WCNOC.

WCNOC disposes of all classes of its low-level radioactive waste at existing third-party repositories. Should disposal capability become unavailable, WCNOC 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 five other nuclear units in the Compact provided most of the preconstruction financing for this project.

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 preconstruction financing, including the WCNOC, as well as the Compact Commission itself, filed a lawsuit in federal court contending that 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. In August 2004, Nebraska and the Compact Commission settled this case. In August 2005, WCNOC received $19.6 million ($1.2 million is KEPCo's share) in proceeds from the Compact as a result of the settlement. In 2006, KEPCo received $0.1 million of interest income from the Compact.

Note 5: Investments in Associated Organizations

Investments in associated organizations are carried at cost. At December 31, 2006 and 2005, investments in associated organizations consisted of the following:

	2006	2005
CFC		
Memberships	$ 1,000	$ 1,000
Capital term certificates	395,970	395,970
Subordinated term certificates	2,205,000	2,205,000
Patronage capital certificates	25,134	16,566
Equity term certificates	592,743	631,150
	3,219,847	3,249,686
Other	152,306	142,514
	$ 3,372,153	$ 3,392,200

Note 6: 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 $4.3 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.

Note 7: Deferred Charges

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 ($14.9 net of accumulated amortization as of December 31, 2006). 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 enabled 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 Statement of Financial Accounting Standard No. 92, Accounting for Phase-In Plans (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.

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 and amounts to $3.1 million for each of the years ended December 31, 2006 and 2005.

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.

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. Additions to the deferred incremental outage costs were $4.1 million and $3.6 million in 2006 and 2005, respectively. The current year amortization of the deferred incremental outage costs was $2.6 million and $2.3 million in 2006 and 2005, respectively.

Other Deferred Charges

KEPCo includes in other deferred charges the early call premium resulting from refinancings. These early call premiums are amortized using the effective interest method over the remaining life of the new agreements.

Note 8: Short-Term Borrowings

As of December 31, 2005, KEPCo has a $15 million line of credit outstanding with the CFC. This line of credit has a term of 24 months. There were outstanding borrowings of $3,521,028 and $0 at December 31, 2006, and December 31, 2005, respectively. Interest varies and was 7.15% at December 31, 2006.

Note 9: 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:

	2006	2005
Mortgage notes payable to the FFB at fixed rates varying from 3.616% to 9.206%, payable in quarterly installments through 2018*	$ 79,232,070	$ 81,792,204
Mortgage notes payable to the Grantor Trust Series 1997 at a rate of 7.522%, payable semiannually, principle payments commencing in 1999 and continuing annually through 2017	43,340,000	45,640,000
Floating/fixed rate pollution control revenue bonds, City of Burlington, Kansas, Pooled Series 1985C, variable interest rate (ranging from 3.53% to 3.64% at December 31, 2006) payable annually through 2015	26,700,000	28,500,000
Mortgage note payable and equity certificate loan to the National Rural Utilities Cooperative Finance Corporation at fixed rates of 5.95%, payable quarterly through 2017	4,162,915	4,440,788
	153,434,985	160,372,992
Less current maturities	11,162,495	10,464,348
	$ 142,272,490	$ 149,908,644

* The mortgage notes payable to FFB are presented net of $0 and $3,526,341 of cash deposited with the RUS for the future repayment of debt as of December 31, 2006 and 2005, respectively. These deposits are restricted for the future repayment of FFB debt and earn interest at a rate of 5%.

Aggregate maturities of long-term debt for the next five years and thereafter are as follows:

2007	$ 11,162,495
2008	11,950,139
2009	12,771,958
2010	13,689,904
2011	14,766,747
Thereafter	89,093,742
	$ 153,434,985

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 distribution 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 such restrictive covenants as of December 31, 2006 and 2005.

In 1997, KEPCo refinanced its mortgage notes payable to the 1988 CFC Grantor Trust through the establish-

ment 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, 2006, the termination obligation associated with the assigned swap agreement to early retire the mortgage notes payable is approximately $6.4 million. This fair value estimate is based on information available at December 31, 2006, and is expected to fluctuate in the future based on changes in interest rates and outstanding principal balance.

KEPCo also is 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.

Note 10: Benefit Plans

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 expense under this program was $0.2 million for each of the years ended December 31, 2006 and 2005.

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, 2006 and 2005.

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:

	2006	2005
Changes in benefit obligation		
Benefit obligation at beginning of year	$ 9,132,420	$ 7,553,340
Service cost	414,240	359,940
Interest cost	548,040	476,160
Actuarial loss	168,840	869,580
Benefits paid	(151,320)	(126,600)
Benefit obligation at end of year	$ 10,112,220	$ 9,132,420
Accumulated benefit obligation	$ 7,958,220	$ 7,059,780

Plan assets are invested in insurance contracts, corporate bonds, equity securities, United States government securities and short-term investments.

	2006	2005
Changes in plan assets		
Fair value of plan assets at beginning of year	$ 5,074,740	$ 4,147,800
Actual return on plan assets	554,760	380,280
Contributions during the year	608,460	649,020
Benefits paid	(127,080)	(102,360)
Fair value of plan assets at end of year	$ 6,110,880	$ 5,074,740
Funded status	(4,001,340)	(4,057,680)
Unrecognized net actuarial loss	2,498,520	2,661,660
Unrecognized prior service cost	—	24,060
Unrecognized net transition obligation	—	43,560
Postmeasurement date adjustments	148,560	26,220
Accrued benefit cost	$ (1,354,260)	$ (1,302,180)
Actuarial assumptions used to determine benefit obligations		
Discount rate	5.70%	5.75%
Annual salary increase rate	3.25%	3.25%

The asset allocation for the plans at the end of 2006 and 2005, and the target allocation for 2006 by asset category are as follows:

	Target Allocation for 2006	Plan Assets 2006	Plan Assets 2005
Asset category			
Equity securities	65%	63%	65%
Debt securities	35%	34	29
Other	0–5%	3	6
		100%	100%

WCNOC's pension plan investment strategy supports the objective 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.

KEPCo's share of the net periodic pension costs were as follows for the years ended December 31:

	2006	2005
Service cost	$ 414,240	$ 359,940
Interest cost on projected benefit obligation	548,040	476,160
Expected return on plan assets	(437,580)	(397,560)
Amortization of actuarial loss	231,420	171,060
Other	11,280	11,280
Total net periodic pension cost	$ 767,400	$ 620,880
Actuarial assumptions used to determine net periodic pension cost		
Discount rate	5.75%	6.00%
Expected return on plan assets	8.25%	8.75%
Annual salary increase rate	3.25%	3.00%

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 expectation 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 $0.8 million will be made to the plans in 2007.

Estimated future benefit payments for the plans, which reflect expected future services, are as follows:

2007	$ 156,000
2008	186,000
2009	216,000
2010	258,000
2011	306,000
Thereafter	2,574,000
	$ 3,696,000

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 $0.6 million and $0.5 million as of December 31, 2006 and 2005, respectively.

Note 11: Commitments and Contingencies

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.

Nuclear Liability and Insurance

Pursuant to the Price-Anderson Act, which was reauthorized through December 31, 2025, by the Energy Policy Act of 2005, KEPCo is 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 industrywide retrospective assessment program. Under this retrospective assessment program, owners are jointly and severally subject to an assessment of up to $100.6 million ($6.0 million–KEPCo's share) at any commercial reactor in the country, payable at no more than $15.0 million ($0.9 million–KEPCo's share) per incident per year, per reactor. 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 the worker radiation claims insurance. The next scheduled inflation adjustment is scheduled for July 1, 2008. In addition, Congress could impose additional revenue-raising measures to pay claims.

The owners of Wolf Creek 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 Nuclear Regulatory Commission. KEPCo's share of any remaining proceeds can be used to pay for property damage, decontamination expenses, or if certain requirements are met, including nuclear 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 property 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 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.

Decommissioning Insurances

KEPCo carries premature decommissioning insurance that 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 Nuclear Regulatory Commission (NRC) and to pay for on-site property damages. Once the NRC property rule requiring insurance proceeds to be used first 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.

Nuclear Fuel Commitments

At December 31, 2006, KEPCo's share of WCNOC's nuclear fuel commitments was approximately $9.6 million for uranium concentrates expiring in 2017, $1.3 million for conversion expiring in 2017, $18.6 million for enrichment expiring at various times through 2024, and $6.8 million for fabrication through 2024.

Purchase Power Commitments

KEPCo has supply contracts with various utility companies to purchase power to supplement generation in the given service areas. KEPCo has a five-year contract with Westar Energy, Inc. through May 2008, with minimum purchase commitments of 85 megawatts per year.

KEPCo has provided the Southwest Power Pool a letter of credit to help insure power is available if needed.

Note 12: 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 carry 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, 2006.

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-rated 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, 2006	
	Carrying Value	**Fair Value**
Cash and cash equivalents	$ 3,271,471	$ 3,271,471
Investments in associated organizations (including investments in CFC)	3,372,153	3,372,153
Bond fund reserve	4,295,806	4,479,135
Decommissioning fund	9,245,665	9,245,665
Fixed-rate debt	126,734,987	126,178,186
Variable-rate debt	26,700,000	26,700,000

Note 13: 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 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 Stated 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 2006 and 2005.

Note 14: Future Change in Accounting Principle

The FASB recently issued Statement No. 158, *Employers' Accounting for Defined Benefit Pension and Other Post-retirement Plans* (SFAS 158), which revises the accounting and disclosure requirements in the financial statements of employers with respect to defined benefit pension and other postretirement plans. The statement requires an employer to currently recognize the funded status of defined benefit plans, the difference between the fair value of plan assets and the projected benefit obligation on the employers' balance sheet. SFAS 158 is effective for fiscal years ended after June 15, 2007; thus, the Cooperative expects to first apply the recognition of the funded status during its year ending December 31, 2007. Additionally, the statement has eliminated the current measurement option and requires the measurement date to be as of the balance sheet date for fiscal year ending after December 15, 2008. The Cooperative's measurement date is currently as of the balance sheet date.

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