WOLF CREEK
NUCLEAR OPERATING CORPORATION

May 7, 2009

Richard D. Flannigan
Manager Regulatory Affairs

RA 09-0072

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

Subject: Docket No. 50-482: Transmittal of 2008 Annual Financial Reports

Gentlemen:

Wolf Creek Nuclear Operating Corporation (WCNOC) is transmitting one copy each of the 2008 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) 364-4117, or Diane Hooper at (620) 364-4041.

Sincerely,

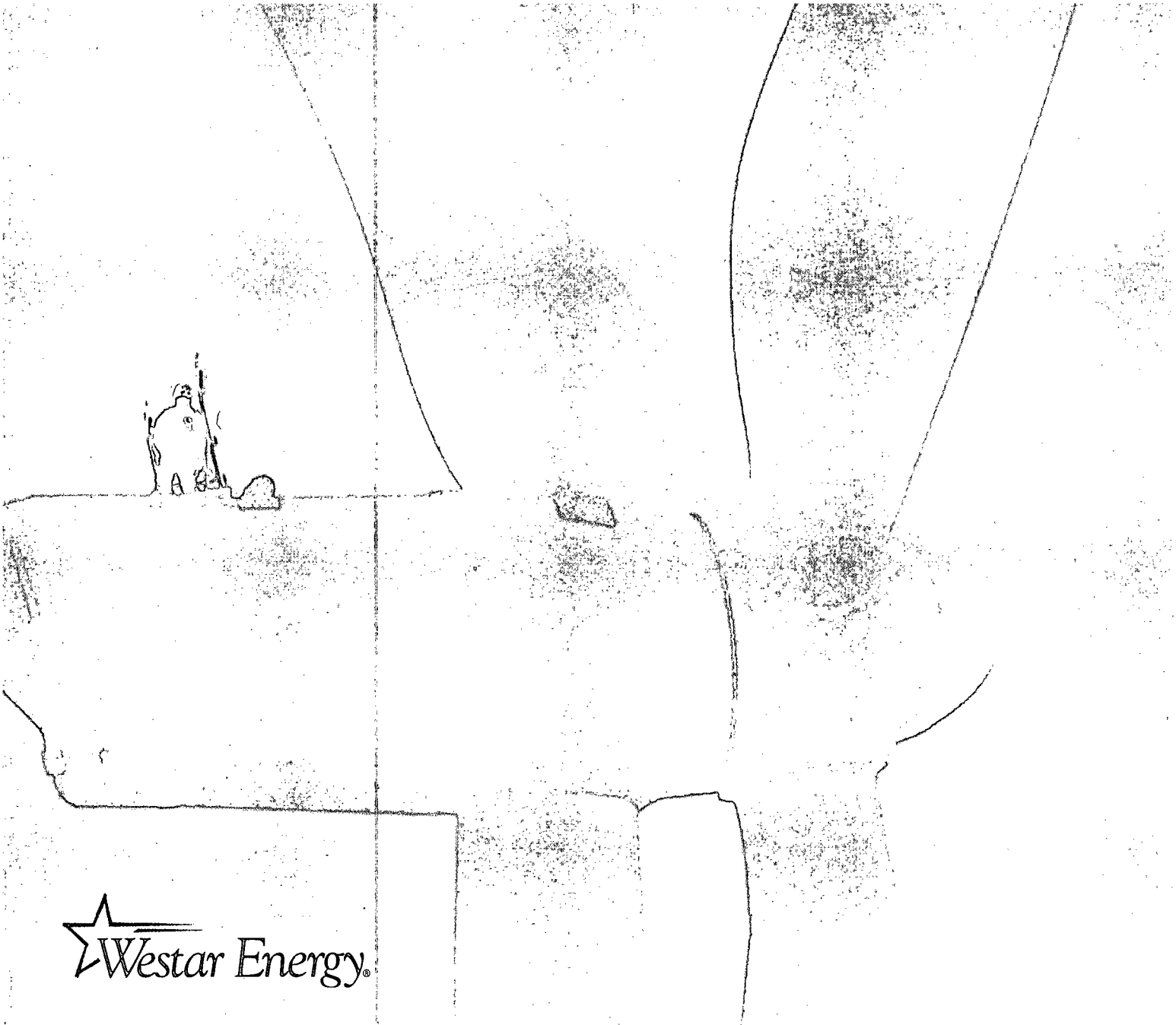
Richard D. Flannigan

RDF/rlt

Enclosures (3)

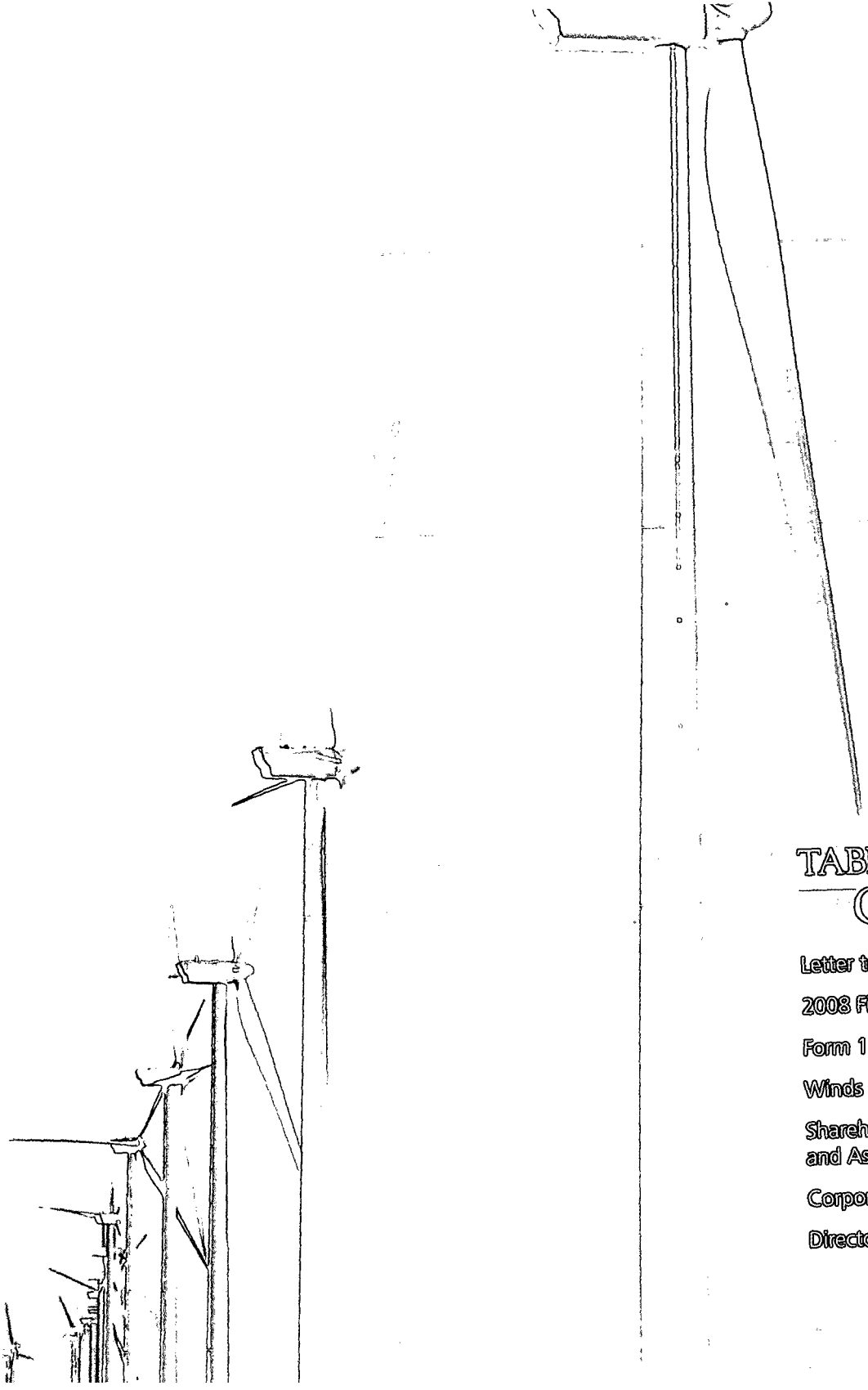
cc: E. E. Collins (NRC), w/e
V. G. Gaddy (NRC), w/e
B. K. Singal (NRC), w/e
Senior Resident Inspector (NRC), w/e

M004
KIRR



Westar Energy®

2008 ANNUAL REPORT



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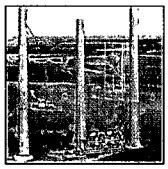
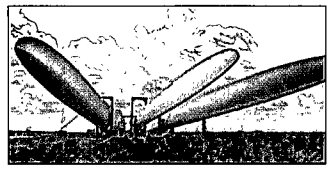
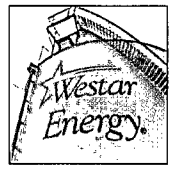
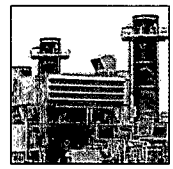
In our letter last year, we emphasized how we were executing an expansion plan to double Westar's investment in utility plants and that we would seek a significant increase in our base rates to begin recovering expenditures for this expansion plan.

First, a progress report on our growth plan: We are successfully wrapping up the first phase of our major capital expenditures.

- We completed our 295-megawatts of wind power projects and are now delivering clean, renewable energy to our customers.




DEAR SHAREHOLDERS

- We were ahead of schedule and on budget for completing our new natural gas power plant near Emporia, Kansas. And though we originally estimated that it would produce 610 megawatts, the performance of the units on-line now has exceeded expectations; the plant is now rated at 665 megawatts.

- We are on schedule for environmental upgrades in air quality at our flagship coal plant, Jeffrey Energy Center.

- And we are on schedule constructing new, high voltage transmission line projects. We energized the first major segment in December.

Second, how well are we doing recovering your investment in rates?

- We achieved a unanimous agreement among all participants in our rate case. In January 2009, the Kansas Corporation Commission approved that agreement, allowing us to increase our base rates by 11 percent or $130 million annually. The agreement also permits us to use an abbreviated regulatory process to include in our rates the portions of our investment in wind generators and Emporia Energy Center that were not yet reflected in this most recent rate case.

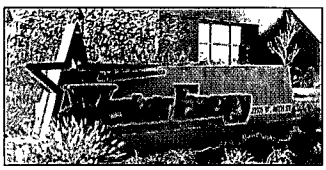
- New investments in our transmission network and in air quality improvements at our power plants are now being recovered through distinct customer charges, which greatly reduces the lag between making those investments and when we begin recovering them in rates.

- Our costs for generating fuels and purchased power are also being recovered nearly in real time by a separate charge on customers' bills.

While growing our business we must also meet our commitments for service reliability and safety. Our service reliability improved in 2008, with customers experiencing an all-time low average of 1.3 interruptions. We also had the best employee safety performance in our history.

We are always conscious of the savings you have entrusted to us by virtue of your stock ownership. As you know, the board increased the dividend by 7.4 percent last year, and even in the present economic downturn the board was confident enough to increase it by 3.4 percent in February 2009.

Enough about what is going according to plan. How are we faring in the current economic crisis?


There is never a good time for hard times, but Westar is in good shape to deal with the current crisis. Dealing with it, however, doesn't mean ignoring it or making glib assumptions about it passing soon. It's impossible to ignore that our stock price has dropped significantly, along with the shares of other electric utilities. And it's impossible to ignore that the capital markets, for both debt and equity, have been virtually closed at times. Even when there is access, it comes at a much higher price. For more vulnerable companies, current conditions in the capital markets have been brutal, even fatal for a few.

Westar is in a good position to deal with this turmoil, better than most of our peers. For example, just prior to the credit crunch, last spring we increased our short-term borrowing arrangements, providing an important source of liquidity, and still at attractive borrowing rates. And over the past two years we raised more than half a billion dollars in common equity – at a lower cost than the market offers today – to fund our capital expansion initiatives. In the fourth quarter, when markets were about at their worst, we were still able to issue $300 million in bonds. Although the interest rate on the bonds was higher than we are accustomed to, it still compared favorably with the interest rates others among our peers have been seeing when they issued bonds. We also improved our investment quality credit ratings. In a year when credit quality was declining for most companies, we received from both Fitch and Standard & Poor's rating upgrades on our debt securities.

The present economic mess is very severe, and if it persists, ignoring it could put your investment and our customers at risk. Even a healthy company like Westar isn't immune from these economic conditions. But while the economic conditions are not derailing our business plan, they are severe enough to cause us to take advantage of the flexibility we have built into it.

Our planning has allowed us to tighten our budgets this year in response to the economy, but without abandoning any of our business objectives. The plan to remain nimble and avoid over-committing to a single type of utility plant has been validated in this economic downturn. Our approach to dealing with risk and uncertainty is paying off. More than ever it makes sense

for us to remain flexible, not bet your company on any single large investment, but to plan for off-ramps and detours along the way, always working closely with our regulators to assure that our plans also serve our customers well. We must execute all these things to do what's best for you and our business.

Yet it's important that we keep Westar's situation in the global economic crisis in proper context. Back in 2001 – 2002, for example, when our company had nearly twice as much debt as it should have and had diversified into non-utility misadventures, the path forward was bleaker. Even so, we got through it successfully. Today, Westar is a financially strong company with investment grade credit ratings much better equipped to face the challenges of a difficult economy. But choosing to do nothing, or just assuming business as usual, isn't a responsible option.

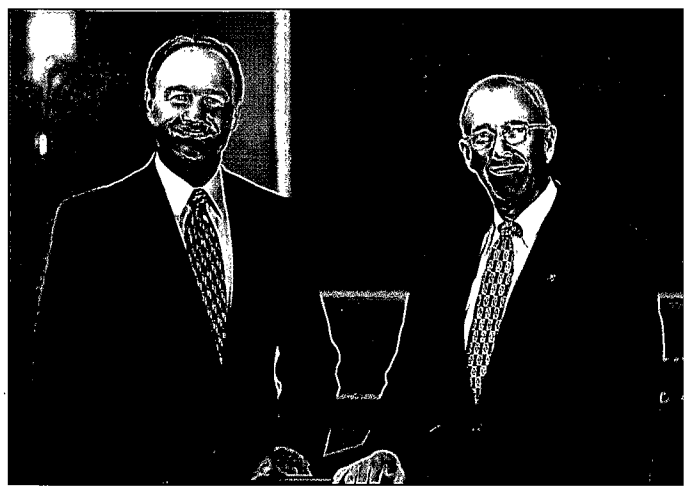
We acknowledge it's as much just plain luck as good planning, but we are virtually finished funding the first, huge phase of our capital expenditure plan for new wind and natural gas generation and environmental upgrades, but we haven't yet started the second phase. As a result of this fortunate timing, and due to our having quickly responded with responsible reductions in our capital spending plans, our hand isn't forced to raise large amounts of capital in these tough markets. It simply makes no sense for us to forge ahead with capital expansions when the cost of capital is now much higher and when many of our business customers are hitting a slump in growth and production and our residential customers are feeling the ill effects of the economy as well. Thanks to the flexibility of our comprehensive planning, the nature of these investments means that we can stay in control of our destiny by adjusting our timing and speed, then restart projects in full force when the economy turns around. Our commitment to being a basic electric utility investing in a broad range of new electric infrastructure remains a good one, because it enables us to stay in control of our business, rather than simply yielding to outside pressures.

This is not our first major challenge, and it won't be our last. We believe that the entire Westar management team will make our investors and our customers proud of how we deal with the challenges of this economic crisis.

Thanks for your investment and trust in Westar Energy.

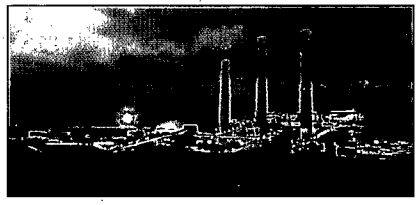
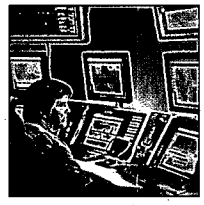
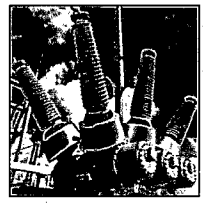
Charles Q Chandler IV, Chairman of the Board

William B Moore, President and CEO



William B. Moore, left, president and chief executive officer, and Charles Q. Chandler IV, chairman of the board.

2008 FINANCIAL MEASURES

	2008	2007
FINANCIAL DATA *(Dollars in Millions)*		
INCOME HIGHLIGHTS		
Sales	**$1,839**	$1,727
Income from continuing operations	**178**	168
Earnings available for common stock	**177**	167
BALANCE SHEET HIGHLIGHTS		
Total assets	**$7,443**	$6,395
Common stock equity	**2,186**	1,827
Capital structure:		
Common equity	**48%**	49%
Preferred stock	**<1%**	1%
Long-term debt	**51%**	50%
OPERATING DATA		
Sales (Thousands of MWh)		
Retail	**19,714**	20,124
Wholesale	**9,384**	10,026
Customers	**679,000**	674,000
COMMON STOCK DATA		
PER SHARE HIGHLIGHTS		
Basic earnings per share	**$1.70**	$1.85
Dividends declared per common share	**$1.16**	$1.08
Book value per share	**$20.18**	$19.14
STOCK PRICE PERFORMANCE		
Common stock price range:		
High	**$25.92**	$28.57
Low	**$15.97**	$22.84
Stock price at year end	**$20.51**	$25.94
Average equivalent common shares outstanding (in thousands)	**103,958**	90,676
Dividend yield (based on year end annualized dividend)	**5.7%**	4.2%

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, 2008

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 First Mortgage Bonds, 6.10% Series due 2047	New York Stock Exchange 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 [X] 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 [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. Yes [X] 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. [X]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company (as defined in Rule 12b-2 of the Act).
Check one: Large accelerated filer [X] Accelerated filer [ ] Non-accelerated filer [ ] Smaller reporting company [ ]

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

The aggregate market value of the voting common equity held by non-affiliates of the registrant was approximately $2,324,082,258 at June 30, 2008.

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	108,484,553 shares
(Class)	(Outstanding at February 18, 2009)

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 2008 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 and economic well-being of our customers.

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, including the impact of changes in interest rates and the cost and availability of capital; inflation; execution of our planned capital expenditure program; performance of our generating plants; changes in accounting requirements and other accounting matters; changing weather; the impact of regional transmission organizations and independent system operators, including the development of market mechanisms for energy markets in which we participate; the impact of economic changes and downturns in the energy industry and the market for trading wholesale energy, including counter-party performance; the outcome of the lawsuit filed by the Department of Justice on behalf of the Environmental Protection Agency on February 4, 2009, alleging violations of the Clean Air Act, and developments related to environmental matters including possible future legislative or regulatory mandates related to emissions of presently unregulated gases or substances; political, legislative, judicial and regulatory developments at the municipal, state and federal level that can affect us or our industry, including in particular those relating to environmental laws; the impact of our potential liability to former executive officers for unpaid compensation and the impact of claims they have made against us related to the termination of their employment; the outcome of the Federal Energy Regulatory Commission investigation of our use of transmission service within the SPP; 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 invested plan assets; the impact of changes in estimates regarding our Wolf Creek Generating Station decommissioning obligation; the impact of adverse changes in market conditions potentially resulting in the need for additional funding for the nuclear decommissioning and pension trusts; 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 and information security considerations; coal, natural gas, uranium, diesel, oil and wholesale electricity prices; cost, 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.

GLOSSARY OF TERMS

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

Abbreviation or Acronym	Definition
2005 KCC Order	December 28, 2005, KCC Order
2009 KCC Order	January 21, 2009, KCC Order
AFUDC	Allowance for Funds Used During Construction
Aquila	Aquila, Inc.
BNSF	Burlington Northern Santa Fe
Btu	British Thermal Units
Central States Compact	Central Interstate Low-Level Radioactive Waste Compact
CO_2	Carbon Dioxide
COLI	Corporate-owned Life Insurance
DOE	Department of Energy
DOJ	Department of Justice
DSPP	Direct Stock Purchase Plan
ECRR	Environmental Cost Recovery Rider
EITF	Emerging Issues Task Force
EPA	Environmental Protection Agency
ERISA	Employee Retirement Income Security Act
FASB	Financial Accounting Standards Board
February 2007 KCC Order	February 8, 2007, KCC Order
FERC	Federal Energy Regulatory Commission
FIN	Financial Accounting Standards Board Interpretation No.
Fitch	Fitch Investors Service
FSP	FASB Staff Position
GAAP	Generally Accepted Accounting Principles
Guardian	Guardian International, Inc.
IRS	Internal Revenue Service
IRS Appeals Settlement	November 2008 tentative settlement with the IRS Office of Appeals
July 2006 Court Order	July 7, 2006, the Kansas Court of Appeals Order
July 2007 KCC Order	July 31, 2007, KCC Order
KCC	Kansas Corporation Commission
KCPL	Kansas City Power & Light Company
KDHE	Kansas Department of Health and Environment
KGE	Kansas Gas and Electric Company
kV	Kilovolt
La Cygne	La Cygne Generating Station
Lehman Brothers	Lehman Brothers Commercial Paper, Inc.
LTISA Plan	Long-Term Incentive and Share Award Plan
Medicare Act	Medicare Prescription Drug Improvement and Modernization Act of 2003
MMBtu	Millions of Btu
Moody's	Moody's Investors Service
MW	Megawatts
MWh	Megawatt hours
NEIL	Nuclear Electric Insurance Limited
NOx	Nitrogen Oxide
NRC	Nuclear Regulatory Commission
NSR Investigation	EPA New Source Review Investigation
ONEOK	ONEOK, Inc.
OTC	Over-the-counter
PCB	Polychlorinated Biphenyl
PPA	Pension Protection Act
Prairie Wind Transmission	Prairie Wind Transmission, LLC
PRB	Powder River Basin
Protection One	Protection One, Inc.
RECA	Retail Energy Cost Adjustment
ROE	Return on Equity
RSUs	Restricted Share Units
RTO	Regional Transmission Organization
S&P	Standard & Poor's Ratings Group
SAB	Staff Accounting Bulletin
SEC	Securities and Exchange Commission
Section 114	Section 114(a) of the Clean Air Act
SFAS	Statement of Financial Accounting Standards
SPP	Southwest Power Pool
SSCGP	Southern Star Central Gas Pipeline
SO_2	Sulfur Dioxide
TDC	Transmission Delivery Charge
VaR	Value-at-Risk
WCNOC	Wolf Creek Nuclear Operating Corporation
Wolf Creek	*Wolf Creek Generating Station*

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 679,000 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

Changes in Rates

We filed an application with the Kansas Corporation Commission (KCC) in May 2008 to increase retail rates by $177.6 million per year. The primary drivers for this application were investments in natural gas generation facilities, wind generation facilities and other capital projects, costs attributable to the 2007 ice storm, higher operating costs and an update of our capital structure. On October 27, 2008, all parties to the proceeding filed an agreement with the KCC supporting a $130.0 million annual increase in our retail rates. On January 21, 2009, the KCC issued an order approving the settlement agreement and the new retail rates became effective on February 3, 2009.

The KCC and Federal Energy Regulatory Commission (FERC) also adjust our rates through the use of rate mechanisms that are designed to track certain portions of the costs of providing utility service. For additional information, see Note 3 of the Notes to Consolidated Financial Statements, "Rate Matters and Regulation."

Economic Conditions

Global and U.S. economic conditions throughout 2008 have begun to impact certain of our industrial and commercial customers and may affect our residential business. Kansas companies are experiencing reduced production and have announced significant employee layoffs. Kansas is experiencing an increase in unemployment claims and the unemployment rate. We cannot determine when these conditions may reverse or whether and to what extent they may affect our results of operations.

Tax Settlements

In February 2008, we reached a settlement with the Internal Revenue Service (IRS) on issues principally related to the method used to capitalize overheads to electric plant for years 1995 through 2002. This settlement resulted in a 2008 net earnings benefit of approximately $39.4 million, including interest, due to the recognition of previously unrecognized tax benefits. The recognition of these previously unrecognized tax benefits resulted in earnings of $0.38 per share for the year ended December 31, 2008.

In January 2009, we reached a settlement with the IRS associated with the re-characterization of the loss we incurred on the sale of Protection One, Inc. (Protection One) from a capital loss to an ordinary loss. This settlement will result in a first quarter 2009 net earnings benefit from discontinued operations of approximately $32.5 million due to the recognition of previously unrecognized tax benefits in accordance with the provisions of Financial Accounting Standards Board (FASB) Interpretation No. (FIN) 48, "Accounting for Uncertainty in Income Taxes — an Interpretation of FASB Statement No. 109."

New Construction Plans

We are making and will continue to make significant investments in new generation, new transmission and air emission controls at existing fossil-fueled power plants.

During 2008, we made capital expenditures of $257.2 million at our power plants for air emission controls. We have identified the potential for us to make up to an additional $1.3 billion of capital expenditures at our power plants for air emissions projects over the next six years.

We have been working with third parties to develop approximately 300 megawatts (MW) of wind generation facilities at three different sites in Kansas. Under the terms of the agreements, we will own approximately half of the wind generation facilities at an expected cost of approximately $282.0 million and will purchase energy produced by the wind generation facilities under twenty year supply contracts for the other half. One of the facilities from which we purchase energy began producing energy in December 2008 and we expect the other two to begin producing energy in early 2009.

On February 12, 2009, we announced that we are seeking bids for as much as 500 MW of additional renewable energy resources. We requested bids contemplating for potentially up to 200 MW of the generation being online by late 2010 with the remainder being potentially online by late 2013. We and our regulators have not yet concluded whether any additional renewable resources will be added.

We are constructing a 345 kilovolt (kV) transmission line from our Gordon Evans Energy Center northwest of Wichita, Kansas, to a new substation near Hutchinson, Kansas, then on to our Summit substation near Salina, Kansas, a distance totaling approximately 100 miles. We completed construction of the first segment in December 2008 and expect the second segment to be completed by June 2010. We expect the total investment in the line and substations to be approximately $200.0 million.

In addition to the transmission line described above, we also plan to construct a new 345 kV line from a substation near Wichita to the Kansas-Oklahoma border, where we will interconnect with new facilities being built by an Oklahoma utility. The preliminary estimate of the investment in the line is approximately $90.0 million, which is subject to change pending final engineering design, labor and materials, among other factors. We expect to begin construction in 2010.

In 2008, we completed the first phase of our Emporia Energy Center, a new natural gas-fired peaking power plant consisting of seven combustion turbines located near Emporia in Lyon County, Kansas, comprising approximately 350 MW of capacity. We expect to complete construction of the second phase, consisting of two generating units that will add an additional approximately 320 MW of generating capacity, early in 2009 for a total investment of about $318.0 million.

In May 2008, we and Electric Transmission America, LLC formed Prairie Wind Transmission, LLC (Prairie Wind Transmission), a joint venture company of which we own 50%. Prairie Wind Transmission is proposing to construct approximately 230 miles of 765 kV transmission facilities in Kansas extending west from near Wichita to near Dodge City and then south-southwest to the Kansas-Oklahoma border. On December 2, 2008, FERC approved a number of key rate components related to these transmission facilities and set aside for hearing the establishment of a formula rate and associated protocols. Should Prairie Wind Transmission receive the necessary regulatory approvals from the KCC and FERC, the facilities are expected to be in service by the end of 2013, contingent on a number of factors including the availability and cost of capital, not all of which are under our control. We will incur significant future capital expenditures related to this joint venture if Prairie Wind Transmission receives regulatory approval to build the transmission facilities.

OPERATIONS

General

Westar Energy supplies electric energy at retail to approximately 366,000 customers in central and northeast Kansas and KGE supplies electric energy at retail to approximately 313,000 customers in south-central and southeastern Kansas. We also supply electric energy at wholesale to the electric distribution systems of 31 cities in Kansas and four electric cooperatives in Kansas pursuant to contracts of various lengths. 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 electricity in areas outside our retail service territory.

We have 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 most of our retail customers. As a result of the January 21, 2009, KCC Order (2009 KCC Order), we will bill our customers for fuel on a quarter ahead estimate beginning approximately March 1, 2009. The RECA provides for an annual review by the KCC to reconcile estimated and actual fuel and purchased power costs. The KCC uses this same mechanism as the means by which we refund to customers the margins realized from market-based wholesale sales.

Generation Capacity

We have 6,508 MW of accredited generating capacity in service, of which 2,578 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	3,432	52.7
Nuclear	545	8.4
Natural gas or oil	2,450	37.7
Diesel	81	1.2
Total	6,508	100.0

Our aggregate 2008 peak system net load of 4,754 MW occurred on August 4, 2008. This included 107 MW of potentially interruptible load. Our net generating capacity, combined with firm capacity purchases and sales and the ability to interrupt 107 MW of load, provided a capacity margin of 18% above system peak responsibility at the time of our 2008 peak system net load.

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

Utility[a]	Capacity (MW)	Period Ending
Midwest Energy, Inc.	130	October 2013
Kansas Electric Power Cooperative	187	December 2009
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
Mid-Kansas Electric Company, LLC	175	January 2019
Total	914	

[a] *Under a wholesale agreement that expires in May 2027, we provide base load capacity to the city of McPherson, Kansas, and McPherson provides peaking capacity to us. During 2008, we provided approximately 84 MW to, and received approximately 151 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 MMBtu, our 2008 fuel mix was 79% coal, 13% nuclear and 7% natural gas, with diesel and oil making up less than 1%. In 2009 we expect to use higher percentages of coal and nuclear as we do not expect to experience extended outages at our coal plants or Wolf Creek in 2009. There were extended outages at some of our coal plants and Wolf Creek in 2008. As a result of our new wind generation facilities, 2009 will be the first year in which we expect to produce a significant amount of wind energy. 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 2,164 MW, of which we own and lease a combined 92% share, or 1,991 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 in excess of 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. We made a scheduled re-pricing in 2008. The next re-pricing for those quantities over the scheduled annual minimum will occur in 2013.

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 2008 was approximately $1.57 per MMBtu, or $26.25 per ton.

La Cygne Generating Station: The two coal-fired units at La Cygne Generating Station (La Cygne) have an aggregate generating capacity of 1,418 MW, of which we own or lease a 50% share, or 709 MW. La Cygne unit 1 uses a blended fuel mix containing approximately 90% PRB coal and 10% Kansas/Missouri coal, the latter of which is purchased from time to time from local Kansas and Missouri producers. 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.

During 2008, the average delivered cost of all coal burned at La Cygne unit 1 was approximately $1.31 per MMBtu, or $21.24 per ton. The average delivered cost of coal burned at La Cygne unit 2 was approximately $1.18 per MMBtu, or $19.65 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 770 MW. We purchase coal under a contract with Arch Coal, Inc. (Arch). The current contract with Arch is expected to provide 100% of the coal requirement for these energy centers through 2010.

BNSF transported coal for these energy centers from Wyoming under a contract that expired in December 2008. We have reached a mutual agreement of understanding with BNSF for the continuing provision of coal transportation to these energy centers until we finalize a long-term contract.

During 2008, the average delivered cost of all coal burned in the Lawrence units was approximately $1.22 per MMBtu, or $21.56 per ton. The average delivered cost of all coal burned in the Tecumseh units was approximately $1.24 per MMBtu, or $21.86 per ton.

Natural Gas

We use natural gas as a primary fuel at our Gordon Evans, Murray Gill, Neosho, Abilene, Hutchinson, Spring Creek and Emporia Energy Centers, at the State Line facility and in the gas turbine units at Tecumseh 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 2008, we purchased 22.1 million MMBtu of natural gas for a total cost of $172.0 million. Natural gas accounted for approximately 7% of our total MMBtu of fuel burned during 2008 and approximately 31% of our total fuel expense. From time to time, we may purchase derivative contracts 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. (ONEOK). The Abilene Energy Center is covered under a standard tariff as a large industrial transportation customer while the Hutchinson Energy Center is covered under a rate agreement that expires on April 30, 2009. We plan to renegotiate the agreement for the Hutchinson Energy Center prior to its expiration. We meet a portion of our natural gas transportation requirements for the Gordon Evans, Murray Gill, Lawrence, Tecumseh and Emporia Energy Centers through firm natural gas transportation capacity agreements with Southern Star Central Gas Pipeline (SSCGP). We meet all of the natural gas transportation requirements for the State Line facility through a firm natural gas transportation agreement with SSCGP. The firm transportation agreement that serves the Gordon Evans and Murray Gill Energy Centers has been restructured and extended through April 1, 2020. The agreement for the State Line facility extends through June 1, 2016, while the agreement for the Emporia Energy Center is in place until December 1, 2028, and is renewable for five-year terms thereafter. 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.

Diesel and Oil

Once started with natural gas, the steam units at our Gordon Evans, Murray Gill, Neosho and Hutchinson Energy Centers have the capability to burn No. 6 oil or natural gas. We only burn No. 6 oil when natural gas is unavailable. During 2008, we did not burn any No. 6 oil.

We also use No. 2 diesel 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 No. 2 diesel in the spot market. 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.

During 2008, we burned 0.3 million MMBtu of diesel at a total cost of $5.6 million. Diesel accounted for less than 1% of our total MMBtu of fuel burned during 2008 and approximately 1% of our total fuel expense. For additional information on our exposure to commodity price risks, see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

Other Fuel Matters

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

	2008	2007	2006
Per MMBtu:			
Nuclear	$ 0.44	$ 0.43	$ 0.41
Coal	1.42	1.27	1.25
Natural gas	7.77	6.51	6.49
Diesel/oil	21.01	15.18	9.19
Per MWh Generation:			
Nuclear	$ 4.57	$ 4.46	$ 4.28
Coal	15.75	13.92	13.69
Natural gas/diesel/oil	79.50	67.65	66.91
All generating stations	18.99	15.51	14.94

Purchased Power

We purchase electricity in addition to generating it ourselves. Factors that cause us to make such purchases include planned and unscheduled outages at our generating plants, prices for wholesale energy compared to generation costs, 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. Purchased power for the year ended December 31, 2008, comprised approximately 20% of our total fuel and purchased power expenses. The weighted average cost of purchased power was $58.96 per megawatt hour (MWh) in 2008, $61.04 per MWh in 2007 and $54.90 per MWh in 2006.

Energy Marketing Activities

We engage in both financial and physical trading with the objective of increasing profits, managing commodity price risk and enhancing system reliability. We trade electricity and other energy-related products using a variety of financial instruments, including future contracts, options and swaps, and we trade energy commodity contracts.

Nuclear Generation

General

Wolf Creek is a 1,160 MW nuclear power plant located near Burlington, Kansas. KGE owns a 47% interest in Wolf Creek, or 545 MW, which represents 8% of our total generating capacity. KCPL owns an equal 47% interest, with Kansas Electric Power Cooperative, Inc. 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. In November 2008, the NRC approved WCNOC's request and Wolf Creek's operating license was extended until 2045.

Fuel Supply

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 87% of uranium and conversion services after that date through September 2018. The owners also have under contract 100% of the uranium enrichment and fabrication required to operate Wolf Creek through March 2025.

Because of a production delay at a mine from which Wolf Creek expected to receive future supplies of uranium, it is possible that contracted uranium deliveries scheduled for 2010 and some years beyond could be reduced, necessitating an increase in the amount of uranium planned for purchase in those years. Wolf Creek's on-going operations strategies, including previous acquisition of inventory, are expected to minimize the impact of such reductions.

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.

Radioactive Waste Disposal

Under the Nuclear Waste Policy Act of 1982, the Department of Energy (DOE) is responsible for the permanent disposal of spent nuclear fuel. Wolf Creek pays into a federal Nuclear Waste Fund administered by the DOE a quarterly fee for the future disposal of spent nuclear fuel. Our share of the fee was $3.5 million in 2008, $4.4 million in 2007 and $4.1 million in 2006 and is calculated as one-tenth of a cent for each kilowatt-hour of net nuclear generation delivered to customers. We include these costs in fuel and purchased power expense.

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. On June 3, 2008, the DOE submitted a license application to the NRC seeking authorization to construct the nuclear waste repository at the Yucca Mountain site. 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.

Wolf Creek disposes of all classes of its low-level radioactive waste at existing third-party repositories. One of those repositories was located in Barnwell, South Carolina. However, as of July 1, 2008, the State of South Carolina no longer accepts waste from generators other than those located in South Carolina, Connecticut, and New Jersey — the three states that make up the Atlantic Interstate

Low-Level Radioactive Waste Management Compact. We expect that another site in the state of Utah will remain available to Wolf Creek. 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. An initial effort in the 1990s to license the construction of a disposal facility in Nebraska failed and the Central States Compact Commission revoked Nebraska's membership in the Central States Compact. There has not been another effort to develop a disposal facility in the Central States Compact region.

Outages

Wolf Creek operates on an 18-month planned refueling and maintenance outage schedule. Wolf Creek was shut down for 55 days in 2008 for refueling and maintenance. During outages at the plant, we meet 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 fall of 2009 for refueling and maintenance.

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. 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 next review is scheduled to occur in 2009.

The KCC reviews nuclear decommissioning plans in two phases. Phase one is the approval of the revised nuclear decommissioning study including the estimated costs to decommission the plant. 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. The actual nuclear decommissioning costs may vary from the estimates because of changes in regulations, technologies 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 is 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 operating license expires in 2045. 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 were 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 for nuclear decommissioning approximately $2.9 million in 2008 and 2007 and $3.9 million in 2006. We record our investment in the nuclear decommissioning fund at fair value. The fair value approximated $85.6 million as of December 31, 2008 and $122.3 million as of December 31, 2007. During 2008, the value of these financial assets declined significantly. As a result, we will likely have to contribute additional amounts to the nuclear decommissioning fund. We expect to collect those amounts from our customers.

Competition and Deregulation

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. Furthermore, FERC issued an order encouraging the formation of regional transmission organizations (RTO). RTOs are designed to control the wholesale transmission services of the utilities in their regions, thereby facilitating competitive wholesale power markets.

Regional Transmission Organization

We are a member of the Southwest Power Pool (SPP), the RTO in our region. 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.

Real-Time Energy Imbalance Market

On February 1, 2007, the SPP implemented the real-time energy imbalance market as required by FERC to accommodate financial settlement of energy imbalances within the SPP region. The

objective of the real-time market system is to permit an efficient balancing of energy production and consumption through the use of a least cost economic dispatch system. It also provides a ready market for the economical purchase and sale of excess energy maximizing the available transmission system. The company participates in this market.

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

Requests for Changes in Transmission Rates

On December 2, 2008, FERC issued an order approving a settlement of our transmission formula rate that allows us to include our anticipated transmission capital expenditures for the current year in our transmission formula rate, subject to true up. In addition to the true up, we expect to update our transmission formula rate in January of each year to reflect changes in our projected operating costs and investments.

On March 24, 2008, FERC issued an order that granted our requested incentives of an additional 100 basis points above the base allowed return on equity (ROE) and a 15-year accelerated recovery for an approximately 100 mile, 345 kV transmission line that will run from near Wichita, Kansas, to near Salina, Kansas. We completed construction of the first segment of this line in December 2008 and expect the second segment to be completed by June 2010. We estimate the line will cost approximately $200.0 million.

In November 2007, we filed applications with FERC that proposed changes in the capital structure used in our transmission formula rate. FERC accepted the proposed changes and the rate change went into effect on June 1, 2007. At December 31, 2008, we had a $2.8 million refund obligation related to this matter, which includes the amount we have collected since June 1, 2007, plus interest on that amount.

On May 2, 2005, we filed applications with FERC that proposed a transmission formula rate providing for annual adjustments to our transmission tariff. 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 (TDC). In November 2007, FERC approved a settlement providing for the rate change effective December 1, 2005, and a refund to customers of $3.4 million.

Request for Increase in Revolving Credit Facility

On January 11, 2008, we filed a request with FERC for authority to issue short-term securities and to pledge KGE mortgage bonds in order to increase the size of Westar Energy's revolving credit facility to $750.0 million. On February 15, 2008, FERC granted our request. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Capital Resources" for more information.

Environmental Matters

General

We are subject to various federal, state and local environmental laws and regulations. Environmental laws and regulations affecting power plants are overlapping, complex, subject to changes in interpretation and implementation, and have tended to become more stringent over time. 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, disposal and clean-up 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, regulations and permits, or fail to obtain and maintain necessary permits, we could be fined or otherwise sanctioned by regulators, and such fines or sanctions may not be recoverable in rates. We have incurred and will continue to incur capital and other expenditures to comply with environmental laws and regulations. Certain of these costs are recoverable through the environmental cost recovery rider (ECRR), which allows for the more timely inclusion in retail rates of capital investments related directly to environmental improvements required by the Clean Air Act, as well as many of the costs related to compliance with other environmental laws and regulations. However, there can be no assurance that we will be able to recover all such costs from our customers or that the costs to comply with existing or future environmental laws and regulations will not have a material adverse effect on our consolidated financial statements.

Air Emissions

The Clean Air Act, state laws and implementing regulations impose, among other things, limitations on pollutants generated during our operations, 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 and natural gas and have equipped some of 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 certain emissions. We have installed continuous emissions monitoring and reporting equipment in order to meet these 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 allowances for each affected 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 2008, we had SO_2 allowances adequate to meet planned generation and we expect to have enough in 2009. In the future if we need to purchase additional allowances our operating costs would increase. We expect to recover the cost of emission allowances through the RECA although there are no guarantees we will be able

to do so. The price of emissions allowances is determined by market forces and changes over time.

On February 28, 2008, we reached an agreement with the KDHE to implement a plan to improve efficiency and to install new equipment to reduce regulated emissions from Jeffrey Energy Center. The projects are designed to meet requirements of the Clean Air Visibility Rule and reduce emissions over our entire generating fleet by eliminating more than 70% of SO_2 and reducing nitrous oxides between 50% and 65%.

On March 15, 2005, the EPA issued the Clean Air Mercury Rule. Beginning in 2010, the rule caps permanently and reduces the amount of mercury that may be emitted from coal-fired power plants. However, on February 8, 2008, the U.S. District Court of Appeals for the District of Columbia vacated the Clean Air Mercury Rule. While the ultimate impact of this ruling on our operations is currently unknown, we believe that mercury emissions controls may be required in the future and that the costs to comply with these requirements may 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,
- additional legislation introduced in the past few years in Congress requiring reductions of presently unregulated gases related primarily to concerns about climate change, and
- state legislation introduced recently that could require mitigation of CO_2 emissions.

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 Costs

We have identified the potential for us to make up to $1.3 billion of capital expenditures at our power plants for environmental air emissions projects during the next six years. This estimate could materially increase or decrease depending on the timing and the nature of required investments, the specific outcomes resulting from interpretation of existing regulations, new regulations, legislation and the resolution of the EPA New Source Review Investigation (NSR Investigation) and the related Department of Justice (DOJ) lawsuit described below. In addition to the capital investment, in the event we install new equipment as a result of the NSR Investigation and the related DOJ lawsuit, such equipment may cause us to incur significant increases in annual operating and maintenance expense and may reduce net production from our power plants. The degree to which we will need to reduce emissions and the timing of when such emissions controls may be required is uncertain. In addition, our ability to access capital markets and the availability of materials, equipment and contractors may affect the timing and ultimate amount of these capital investments.

The ECRR allows for the more timely inclusion in retail rates of capital expenditures tied directly to environmental improvements, including those required by the Clean Air Act. However, increased operating and maintenance costs, other than expenses related to production-related consumables, can be recovered only through a change in base rates.

New Source Review Investigation

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 the New Source Review permitting program 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 reasonably have been expected to result in a significant net increase in emissions. The New Source Review program requires companies to obtain permits and, if necessary, install control equipment to address 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 certain requirements of the New Source Review program. On February 4, 2009, the DOJ filed a lawsuit against us in U.S. District Court in the District of Kansas asserting substantially the same claims. A decision in favor of the DOJ and the EPA, or a settlement prior to such a decision, if reached, 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. Our ultimate costs to resolve the NSR Investigation and the related DOJ lawsuit could be material. We believe that costs related to updating or installing emissions controls would qualify for recovery in the prices we are allowed to charge our customers. If, however, a penalty is assessed against us, 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 identified as being responsible for the clean-up of 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, 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 the former manufactured gas sites identified in Missouri is limited to $7.5 million by the terms of an environmental indemnity agreement with the purchaser of our former Missouri assets.

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 18, 2009, we had 2,415 employees. In 2008, we negotiated a three-year contract with Local 304 and Local 1523 of the International Brotherhood of Electrical Workers that extends through June 30, 2011. The contract covered 1,343 employees as of February 18, 2009.

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
William B. Moore	56	Director, President and Chief Executive Officer (since July 2007)	**Westar Energy, Inc.** President and Chief Operating Officer (March 2006 to June 2007) Executive Vice President and Chief Operating Officer (December 2002 to March 2006)
James J. Ludwig	50	Executive Vice President, Public Affairs and Consumer Services (since July 2007)	**Westar Energy, Inc.** Vice President, Regulatory and Public Affairs (March 2006 to June 2007) Vice President, Public Affairs (January 2003 to March 2006)
Mark A. Ruelle	47	Executive Vice President and Chief Financial Officer (since January 2003)	
Douglas R. Sterbenz	45	Executive Vice President and Chief Operating Officer (since July 2007)	**Westar Energy, Inc.** Executive Vice President, Generation and Marketing (March 2006 to June 2007) Senior Vice President, Generation and Marketing (October 2001 to March 2006)
Jeffrey L. Beasley	50	Vice President, Corporate Compliance and Internal Audit (since September 2007)	**Westar Energy, Inc.** Executive Director, Corporate Compliance and Internal Audit (September 2006 to September 2007) Director, Corporate Finance (March 2005 to September 2006) Director, Accounting Services (June 2003 to March 2005)
Larry D. Irick	52	Vice President, General Counsel and Corporate Secretary (since February 2003)	
Michael Lennen	63	Vice President, Regulatory Affairs (since July 2007)	**Morris, Laing, Evans, Brock & Kennedy, Chartered** Partner (January 1990 to July 2007)
Lee Wages	60	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 statements. 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 and FERC

The KCC and FERC regulate many aspects of our business and operations, including the rates that we charge customers for electric service. Retail rates are set by the KCC while wholesale

and transmission rates are set by FERC. Both the KCC and FERC use 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 and FERC set rates at a level calculated to recover such costs and a permitted return on investment. On January 21, 2009, the KCC authorized a $130.0 million increase in our retail rates to reflect our investment in natural gas generation facilities, wind generation facilities and other capital projects, costs attributable to the 2007 ice storm, higher operating costs and an update of our capital structure. The new retail rates became effective on February 3, 2009.

Our Costs May Not be Fully Recovered in Rates

Except to the extent the KCC and FERC permit us to modify our prices by using specific adjustments and riders, such as the RECA, TDC and ECRR, 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 our rates be reviewed for possible adjustment.

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 extended or unplanned outages because of equipment failure, weather, failure by our contractors or subcontractors to meet commitments and other factors largely beyond our control. In such events, we must either produce replacement power from our other, usually less efficient, units or purchase power from others at unpredictable and potentially higher costs in order to meet our sales obligations. In addition, such events 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 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 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 financial statements. 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 Relating to Environmental Matters

Under Section 114, the EPA is conducting investigations nationwide to determine whether modifications at coal-fired power plants are subject to the New Source Review permitting program 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 reasonably have been expected to result in a significant net increase in emissions. The New Source Review program requires companies to obtain permits and, if necessary, install control equipment to address 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 certain requirements of the New Source Review program. On February 4, 2009, the DOJ filed a lawsuit against us in U.S. District Court in the District of Kansas asserting substantially the same claims. A decision in favor of the DOJ and the EPA, or a settlement prior to such a decision, if reached, 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. Our ultimate costs to resolve the NSR Investigation and the related DOJ lawsuit could be material. We believe that costs related to updating or installing emissions controls would qualify for recovery in the prices we are allowed to charge our customers. If, however, a penalty is assessed against us, 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.

Our activities are subject to extensive and changing environmental regulation by federal, state and local governmental authorities, particularly relating to air emissions. In addition to laws currently in effect, numerous laws and regulations have been enacted and proposed relating to increasing national and international concern about possible global warming caused by the atmospheric release of CO_2 and other gases by industrial and other sources, including the utility industry. On November 15, 2007, the governors of six Midwestern states, including Kansas, signed the Midwest Greenhouse Gas Reduction Accord, under which the member states will, among other things, establish greenhouse gas reduction targets and develop a market-based and multi-sector cap-and-trade mechanism to help achieve such targets. In addition, on October 18, 2007, the KDHE denied an application by an unrelated utility for an air quality permit for two new proposed coal generators in Western Kansas in part because of concerns about the increase in CO_2 and emissions and the potential ill effects those plants might have on the environment and health. The KDHE noted that the decision constituted a first step in emerging policy to address existing and future CO_2 emissions in Kansas. The Midwest Greenhouse Gas Reduction Accord or other new or changed laws and regulations, as well as third party litigation that may be brought against us or our competitors, could result in requirements to install costly equipment, increase our operating expenses, reduce production from our plants or take other actions we are unable to identify at this time.

The degree to which we may 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 existing regulations, new regulations, legislation and the resolution of the NSR Investigation and the related DOJ lawsuit described above. Although we expect to recover in our rates most of 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 or the costs of any failure to comply with laws and regulations. Failure to recover these associated costs could have a material adverse effect on our consolidated financial statements.

Accounting Regulations Unique to Public Utilities Could Change

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, 2008, we had recorded $829.2 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; (iii) a result of other regulatory actions that restrict cost recovery to a level insufficient to recover costs; or (iv) a change from current generally accepted accounting principles (GAAP) to another set of standards that does not recognize regulatory assets or liabilities, 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 statements.

Our Planned Capital Expenditures Are Significant To Our Results Of Operations

During the period from 2009 through 2011 and for the immediate years beyond, we plan to continue significant capital expenditures toward large projects including the expansion and modernization of our generation fleet and transmission network. Our anticipated capital expenditures for the period from 2009 through 2011, including costs of removal, are approximately $2.4 billion. Delays in engineering and construction times can occur throughout our industry. Because our capital expenditure program is large in comparison to our revenues and assets, cost increases or delays could materially affect our consolidated financial statements.

In addition, in order to fund our capital expenditure program, we rely to a large degree on access to our short-term credit facility and to long-term capital markets for debt and equity as sources of liquidity for capital requirements not satisfied by the cash flow from our operations. The secured and unsecured debt of Westar Energy and KGE are rated investment grade by all three of the best known rating agencies, but we cannot assure that such debt will continue to be rated investment grade. If the rating agencies were to downgrade Westar Energy's or KGE's secured or unsecured debt, our borrowing costs and the interest rates we pay on short-term and long-term debt would likely increase, possibly significantly. Further, market disruptions could increase our cost of borrowing or adversely affect our ability to access financial markets. Additional issuance of equity securities could dilute the value of our shares of our common stock and cause the market price of our common stock to fall. These factors could hinder our access to capital markets and limit or delay our ability to carry out our capital expenditure program.

Further, our recovery of capital expenditures depends in large degree on the outcome of retail and wholesale rate proceedings. Decisions made by the KCC or FERC, or delays in making such decisions, could have a material impact on our consolidated financial statements.

Uncertainty in the Credit Markets and the Impact on the Economy in Our Service Territory

Continuing turmoil in the global credit markets, and the slowing of the global and U.S. economies, may have a number of effects on our operations, financial condition and capital expenditure program. While we cannot provide an exhaustive list of all possible effects, these market conditions may make capital more difficult and costly to obtain; may restrict liquidity available to us through our revolving credit facility; may reduce demand by our customers and increase delinquencies or non-payment by our customers; may adversely impact the financial condition of our suppliers, which may in turn limit our access to inventory or capital equipment; may reduce the credit available to our energy trading counterparties and correspondingly reduce our energy trading activity or increase our exposure to counterparty default; may require us to defer or limit elements of our capital expenditure program; may reduce the value of our financial assets and correspondingly adversely impact our earnings and net cash flow; may require us to provide additional funding to our nuclear decommissioning and pension trusts; and may increase the cost or decrease the availability of insurance to us or make insurance claims more difficult to collect. These and other related effects may have an adverse impact on our consolidated financial statements and in extreme circumstances, the combination of some or all of these effects might impact amounts available for the payment of dividends.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Name/Location	Unit No.	Year Installed	Principal Fuel	Unit Capacity (MW) By Owner: Westar Energy	KGE	Total Company
Abilene Energy Center:						
Abilene, Kansas						
Combustion Turbine	1	1973	Gas	72	—	72
Emporia Energy Center:						
Emporia, Kansas						
Combustion Turbine	1	2008	Gas	45	—	45
	2	2008	Gas	45	—	45
	3	2008	Gas	47	—	47
	4	2008	Gas	46	—	46
	5	2008	Gas	161	—	161
Gordon Evans Energy Center:						
Colwich, Kansas						
Steam Turbines	1	1961	Gas – Oil	—	152	152
	2	1967	Gas – Oil	—	384	384
Combustion Turbines	1	2000	Gas	74	—	74
	2	2000	Gas	72	—	72
	3	2001	Gas	150	—	150
Diesel Generator	1	1969	Diesel	—	3	3
Hutchinson Energy Center:						
Hutchinson, Kansas						
Steam Turbine	4	1965	Gas – Oil	170	—	170
Combustion Turbines	1	1974	Gas	56	—	56
	2	1974	Gas	51	—	51
	3	1974	Gas	56	—	56
	4	1975	Diesel	75	—	75
Diesel Generator	1	1983	Diesel	3	—	3
Jeffrey Energy Center (92%):						
St. Marys, Kansas						
Steam Turbines	1 [a]	1978	Coal	521	144	665
	2 [a]	1980	Coal	517	144	661
	3 [a]	1983	Coal	521	144	665
La Cygne Station (50%):						
La Cygne, Kansas						
Steam Turbines	1 [a]	1973	Coal	—	368	368
	2 [b]	1977	Coal	—	341	341
Lawrence Energy Center:						
Lawrence, Kansas						
Steam Turbines	3	1954	Coal	49	—	49
	4	1960	Coal	108	—	108
	5	1971	Coal	373	—	373
Murray Gill Energy Center:						
Wichita, Kansas						
Steam Turbines	1	1952	Gas	—	39	39
	2	1954	Gas – Oil	—	53	53
	3	1956	Gas – Oil	—	101	101
	4	1959	Gas – Oil	—	93	93
Neosho Energy Center:						
Parsons, Kansas						
Steam Turbine	3	1954	Gas – Oil	—	67	67
Spring Creek Energy Center:						
Edmond, Oklahoma						
Combustion Turbines	1	2001 [c]	Gas	70	—	70
	2	2001 [c]	Gas	69	—	69
	3	2001 [c]	Gas	67	—	67
	4	2001 [c]	Gas	68	—	68
State Line (40%):						
Joplin, Missouri						
Combined Cycle	2-1 [a]	2001	Gas	65	—	65
	2-2 [a]	2001	Gas	65	—	65
	2-3 [a]	2001	Gas	74	—	74
Tecumseh Energy Center:						
Tecumseh, Kansas						
Steam Turbines	7	1957	Coal	72	—	72
	8	1962	Coal	130	—	130
Combustion Turbines	1	1972	Gas	19	—	19
	2	1972	Gas	19	—	19
Wolf Creek Generating Station (47%):						
Burlington, Kansas						
Nuclear	1 [a]	1985	Uranium	—	545	545
Total				3,930	2,578	6,508

[a] *We jointly own La Cygne unit 1 generating unit (50%), Wolf Creek Generating Station (47%) and State Line (40%); and jointly own and lease Jeffrey Energy Center (92%). Unit capacity amounts reflect our ownership and leased percentages 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 and have in service approximately 6,200 miles of transmission lines, approximately 23,800 miles of overhead distribution lines and approximately 4,100 miles of underground distribution lines.

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

ITEM 3. LEGAL PROCEEDINGS

Information on other legal proceedings is set forth in Notes 3, 13 and 15 of the Notes to Consolidated Financial Statements, "Rate Matters and Regulation," "Commitments and Contingencies — New Source Review Investigation" and "Legal Proceedings", respectively, which are incorporated herein by reference.

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

None.

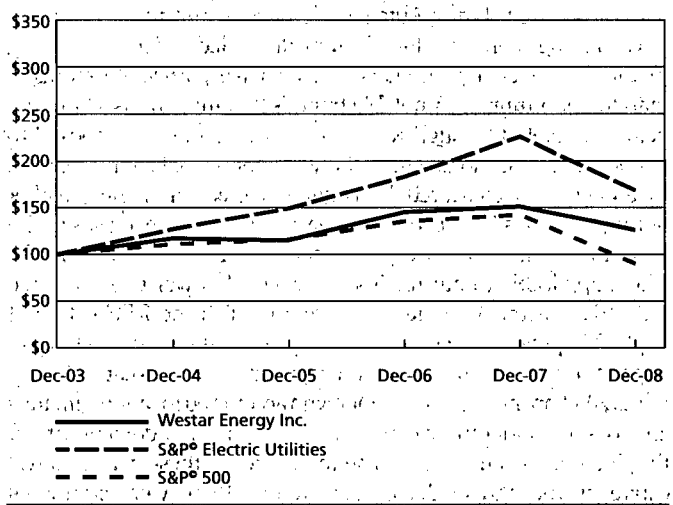
PART II

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, 2003, and ended on December 31, 2008, 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, 2003 with dividends reinvested



	Dec-2003	Dec-2004	Dec-2005	Dec-2006	Dec-2007	Dec-2008
Westar Energy Inc.	$100	$117	$115	$145	$151	$126
S&P 500	$100	$111	$116	$135	$142	$90
S&P Electric Utilities	$100	$127	$149	$183	$226	$168

STOCK TRADING

Our common stock is listed on the New York Stock Exchange and traded under the ticker symbol WR. As of February 18, 2009, there were 23,822 common shareholders of record. For information regarding quarterly common stock price ranges for 2008 and 2007; see Note 20 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 2008 our board of directors declared four quarterly dividends, each at $0.29 per share, reflecting an annual dividend of $1.16 per share. On February 25, 2009, our board of directors declared a quarterly dividend of $0.30 per share on our common stock payable to shareholders on April 1, 2009. The indicated annual dividend rate is $1.20 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 2008. We provide further information on these restrictions in Note 17 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,	2008	2007	2006	2005	2004
			(In Thousands)		
Income Statement Data:					
Sales	$ 1,838,996	$ 1,726,834	$ 1,605,743	$ 1,583,278	$ 1,464,489
Income from continuing operations	178,140	168,354	165,309	134,868	100,080
Earnings available for common stock	177,170	167,384	164,339	134,640	177,900

As of December 31,	2008	2007	2006	2005	2004
			(In Thousands)		
Balance Sheet Data:					
Total assets	$ 7,443,259	$ 6,395,430	$ 5,455,175	$ 5,210,069	$ 5,001,144
Long-term obligations and mandatorily redeemable preferred stock[a]	2,465,968	2,022,493	1,580,108	1,681,301	1,724,967

Year Ended December 31,	2008	2007	2006	2005	2004
Common Stock Data:					
Basic earnings per share available for common stock from continuing operations	$ 1.70	$ 1.85	$ 1.88	$ 1.54	$ 1.19
Basic earnings per share available for common stock	$ 1.70	$ 1.85	$ 1.88	$ 1.55	$ 2.14
Dividends declared per share	$ 1.16	$ 1.08	$ 1.00	$ 0.92	$ 0.80
Book value per share	$ 20.18	$ 19.14	$ 17.61	$ 16.31	$ 16.13
Average equivalent common shares outstanding (in thousands)[b][c][d]	103,958	90,676	87,510	86,855	82,941

[a] *Includes long-term debt and capital leases.*
[b] *In 2004, we issued and sold approximately 12.5 million shares of common stock realizing net proceeds of $245.1 million.*
[c] *In 2007, we issued and sold approximately 8.1 million shares of common stock realizing net proceeds of $195.4 million.*
[d] *In 2008, we issued and sold approximately 12.8 million shares of common stock realizing net proceeds of $293.6 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 2008, and our operating results for the years ended December 31, 2008, 2007 and 2006. 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, 2008:

- Income from operations for the year ended December 31, 2008, decreased compared to the prior year due primarily to a decrease in energy marketing, cooler weather, reduced margins on power sold to a few large industrial customers and additional planned outages at our base load plants in the first and second quarters of 2008. See "— Decrease in Income from Operations" below for additional information;
- We reached a settlement with the IRS on issues principally related to the method used to capitalize overheads to electric plant for the years 1995 through 2002, which resulted in a 2008 net earnings benefit of approximately $39.4 million. See "— Recognition of Previously Unrecognized Tax Benefits" below for additional information. We also recognized $14.6 million in state tax incentives related to investment and jobs creation within the state of Kansas;
- We received regulatory approval to increase retail rates $130.0 million per year. The primary drivers for our rate increase were investments in natural gas generation facilities, wind generation facilities and other capital projects, costs attributable to the 2007 ice storm, higher operating costs and an update of our capital structure. For additional information, see Note 3 of the Notes to Consolidated Financial Statements, "Rate Matters and Regulation;"
- We made capital expenditures of $937.2 million during 2008. See "— Increased Capacity and Future Plans" and "— Liquidity and Capital Resources" below for additional information;
- We issued 12.3 million shares of common stock for net proceeds of $290.2 million through a Sales Agency Financing Agreement, a forward sale agreement and an underwriting agreement. We also issued an additional $450.0 million principal amount of first mortgage bonds as part of our efforts to raise the funds needed for our capital projects. We expect to continue to issue equity and debt securities as external funds are needed to complete planned capital investments;
- As a result of market conditions, we experienced a significant loss in the value of assets in our pension and nuclear decommission trusts. This will increase our pension expense in future periods and will require us to make additional contributions to these trusts;
- Global and U.S. economic conditions throughout 2008 have begun to impact certain of our industrial and commercial customers and may affect our residential business. Kansas companies are experiencing reduced production and have announced significant employee layoffs. Kansas is experiencing an increase in unemployment claims and the unemployment rate. We cannot determine when these conditions may reverse or whether and to what extent they may affect our results of operations.

Decrease in Income from Operations

Income from operations decreased $52.7 million or 16% compared to last year. This decrease is attributable primarily to a decrease in energy marketing, cooler weather, reduced margins on power sold to a few large industrial customers and additional planned outages at our base load plants. Energy marketing decreased $22.5 million due primarily to the need to focus resources toward serving our retail customers during outages, changes in the relationships of prices among energy products historically traded and the continuing maturation of energy markets in which we participate reducing margin opportunities. A notable trend is that more transactions are being completed through RTO-sponsored markets as opposed to negotiated transactions directly between individual counterparties. In addition, as measured by cooling degree days, the weather during 2008 was 20% cooler than last year. While increases in the cost of fuel and purchased power generally are recoverable in the RECA applicable to our retail sales, we sold power to a few large industrial customers under contracts to which the RECA did not apply. Margins on sales to customers under these contracts were approximately $9.9 million lower compared to last year. Effective July 1, 2008, an industrial customer who accounted for approximately 65% of sales under these contracts is now served under a new tariff that incorporates the RECA. The remainder of these contracts will expire by the end of 2009. Furthermore, there were additional planned outages at our base-load plants in 2008 that were longer in duration than the prior year. The additional planned outages required us to use more expensive fuel and to incur additional purchased power expense. This resulted in reduced margins on power sold, notwithstanding higher prevailing market prices. Margins on market-based wholesale sales decreased $9.1 million or 13% compared to last year.

Recognition of Previously Unrecognized Tax Benefits

In December 2007, we reached a tentative settlement with the IRS Office of Appeals on issues principally related to the method used to capitalize overheads to electric plant for years 1995 through 2002. This settlement, which was approved by the Joint Committee on Taxation and accepted by the IRS in February 2008, resulted in a 2008 net earnings benefit of approximately $39.4 million, including interest, due to the recognition of previously unrecognized tax benefits. The recognition of these previously unrecognized tax benefits resulted in earnings of $0.38 per share for the year ended December 31, 2008.

Changes in Rates

We filed an application with the KCC in May 2008 to increase retail rates by $177.6 million per year. The primary drivers for this application were investments in natural gas generation facilities, wind generation facilities and other capital projects, costs attributable to the 2007 ice storm, higher operating costs and an update of our capital structure. On October 27, 2008, all parties to the proceeding filed an agreement with the KCC supporting a

$130.0 million annual increase in our retail rates. On January 21, 2009, the KCC issued an order approving the settlement agreement and the new retail rates became effective on February 3, 2009.

On July 1, 2008, we implemented an initial retail TDC on a revenue neutral basis to capture transmission costs ultimately approved in our 2005 general rate case. On September 18, 2008, the KCC granted our request to adjust the TDC to include more recent transmission costs approved by FERC and attributable to the retail portion of our transmission service. This served to increase our estimated annual retail revenues by $6.1 million.

On May 29, 2008, the KCC issued an order allowing us to increase our ECRR to include costs associated with investments made in 2007. This change went into effect on June 1, 2008, and served to increase our estimated annual retail revenues by $22.0 million.

On December 2, 2008, FERC issued an order approving a settlement of our transmission formula rate that allows us to include our anticipated transmission capital expenditures for the current year in our transmission formula rate, subject to true up. In addition to the true up, we expect to update our transmission formula rate in January of each year to reflect changes in our projected operating costs and investments.

Increased Capacity and Future Plans

In May 2008, we and Electric Transmission America, LLC formed Prairie Wind Transmission, a joint venture company of which we own 50%. Prairie Wind Transmission is proposing to construct approximately 230 miles of 765 kV transmission facilities in Kansas extending west from near Wichita to near Dodge City and then south-southwest to the Kansas-Oklahoma border. On December 2, 2008, FERC approved a number of key rate components related to these transmission facilities and set aside for hearing the establishment of a formula rate and associated protocols. Should Prairie Wind Transmission receive the necessary regulatory approvals from the KCC and FERC, the facilities are expected to be in service by the end of 2013, contingent on a number of factors including the availability and cost of capital, not all of which are under our control. We will incur significant future capital expenditures related to this joint venture if Prairie Wind Transmission receives regulatory approval to build the transmission facilities.

We have been working with third parties to develop approximately 300 MW of wind generation facilities at three different sites in Kansas. Under the terms of the agreements, we will own approximately half of the wind generation facilities at an expected cost of approximately $282.0 million and will purchase energy produced by the wind generation facilities under twenty year supply contracts for the other half. One of the facilities from which we purchase energy began producing energy in December 2008 and we expect the other two to begin producing energy in early 2009.

We are constructing a 345 kV transmission line from our Gordon Evans Energy Center northwest of Wichita, Kansas, to a new substation near Hutchinson, Kansas, then on to our Summit substation near Salina, Kansas, a distance totaling approximately 100 miles. We completed construction of the first segment in December 2008 and expect the second segment to be completed by June 2010. We expect the total investment in the line and substations to be approximately $200.0 million.

In addition to the transmission line described above, we also plan to construct a new 345 kV line from a substation near Wichita to the Kansas-Oklahoma border, where we will interconnect with new facilities being built by an Oklahoma utility. The preliminary estimate of the investment in the line is approximately $90.0 million, which is subject to change pending final engineering design, labor and materials, among other factors. We expect to begin construction in 2010.

In 2008, we completed the first phase of our Emporia Energy Center, a new natural gas-fired peaking power plant consisting of seven combustion turbines located near Emporia in Lyon County, Kansas, comprising approximately 350 MW of capacity. We expect to complete construction of the second phase, consisting of two generating units that will add an additional approximately 320 MW of generating capacity, early in 2009 for a total investment of about $318.0 million.

Economic Conditions

In 2008, global economic growth slowed, liquidity was reduced in global capital markets and the U.S. entered a recession. The downturn became more intense in the fourth quarter of 2008. Growth in industrial production decreased from 2007 levels, and business and consumer confidence declined throughout 2008. The rate of inflation increased in the first half of 2008 with rising food and energy prices, but declined in the latter part of the year.

The state of the economy may adversely affect a number of aspects of our business. While the full impact of these events is currently unknown, several developments can be highlighted.

Certain of our industrial and commercial customers have informed us that they are experiencing a decrease in orders and have reduced production and work schedules. Further, several of our large industrial customers have recently announced significant employee layoffs.

Our residential business may be affected by general economic conditions. The Kansas unemployment rate increased from 4.2% in December 2007 to 5.2% in December 2008. Initial unemployment claims in Kansas jumped to approximately 37,000 claims in December 2008 from approximately 18,000 claims in December 2007.

We cannot predict whether these developments will continue or when the economy generally may stabilize. We also cannot state whether or to what extent any such developments will impact our results of operations, which are affected by economic conditions as well as by a broad number of other factors, including without limitation those factors summarized in this Form 10-K in the sections entitled "Forward Looking Statements" and "Item 1A. Risk Factors."

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 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 regulatory orders, 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	$52,188	$52,188	$5,321
	0.5% increase	(48,682)	(48,682)	(5,170)
Salary scale	0.5% decrease	(13,199)	(13,199)	(2,609)
	0.5% increase	13,462	13,462	2,686
Rate of return on plan assets	0.5% decrease	—	—	2,506
	0.5% increase	—	—	(2,506)

We recorded pension costs of approximately $22.7 million in 2008 and $21.4 million in both 2007 and 2006. These amounts reflect the pension costs of Westar Energy and our 47% responsibility for the pension costs of Wolf Creek. Pension costs for 2009 are expected to be approximately $38.1 million. The increase in pension costs from 2008 to that expected in 2009 is due primarily to significantly lower than expected investment returns in 2008. The investment gains or losses resulting from the difference between the expected return on assets and actual returns earned are deferred in the year the difference arises. The gain or loss recognition occurs by using a four-year moving average value of pension assets to measure the expected return on assets in the pension cost, and by amortizing deferred investment gains or losses over the average remaining service life of employees. See Notes 11 and 12 of the Notes to Consolidated Financial Statements, "Employee Benefit Plans" and "Wolf Creek Employee Benefit Plans," for additional discussion of Westar Energy and Wolf Creek benefit plans, respectively.

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	$8,061	$8,061	$513
	0.5% increase	(7,626)	(7,626)	(520)
Rate of return on plan assets	0.5% decrease	—	—	282
	0.5% increase	—	—	(282)

Revenue Recognition — Energy Sales

We record revenue at the time we deliver electricity to customers. We determine the amounts delivered to individual customers through systematic monthly readings of customer meters. At the end of each month, we estimate the electric usage from the last meter read and record the corresponding unbilled revenue.

The accuracy of our unbilled revenue estimate is affected by factors including fluctuations in energy demands, weather, line losses and changes in the composition of customer classes. We had estimated unbilled revenue of $47.7 million as of December 31, 2008, and $43.7 million as of December 31, 2007.

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 a fuel supply contract and a capacity sale contract, which we record as regulatory liabilities, 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. The prices we use to value these transactions reflect our best estimate of the fair value of these contracts. Results actually achieved from these activities could vary materially from intended results and could affect our consolidated financial statements.

The tables below show the fair value of energy marketing contracts that were outstanding as of December 31, 2008, their sources and maturity periods.

	Fair Value of Contracts
	(In Thousands)
Net fair value of contracts outstanding as of December 31, 2007[a]	$41,502
Contracts outstanding at the beginning of the period that were realized or otherwise settled during the period	(14,879)
Changes in fair value of contracts outstanding at the beginning and end of the period	16,058
Fair value of new contracts entered into during the period	7,683
Fair value of contracts outstanding as of December 31, 2008[a]	$50,364

[a] *Approximately $36.3 million at December 31, 2008, and $34.0 million at December 31, 2007, of the fair value of energy marketing 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, 2008, are summarized in the following table.

		Fair Value of Contracts at End of Period			
Sources of Fair Value	Total Fair Value	Maturity Less Than 1 Year	Maturity 1-3 Years	Maturity 4-5 Years	Maturity Over 5 Years
		(In Thousands)			
Prices actively quoted (futures)	$ 6	$ —	$ 6	$ —	$ —
Prices provided by other external sources (swaps and forwards)	42,239	18,977	16,577	4,512	2,173
Prices based on option pricing models (options and other)[a]	8,119	8,048	950	(670)	(209)
Total fair value of contracts outstanding	$50,364	$27,025	$17,533	$ 3,842	$ 1,964

[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 as required by tax laws and regulatory practices.

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.

We account for uncertainty in income taxes in accordance with FIN 48, "Accounting for Uncertainty in Income Taxes — an Interpretation of FASB Statement No. 109." The application of income tax law is complex. Laws and regulations in this area are voluminous and are often ambiguous. Accordingly, we must make subjective assumptions and judgments regarding income tax exposures. Interpretations of and guidance surrounding income tax laws and regulations change over time. As a result, changes in our subjective assumptions and judgments can materially affect amounts we recognize in the consolidated financial statements. See Note 10 of the Notes to Consolidated Financial Statements, "Taxes," for additional detail of our uncertainty in income taxes.

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 FIN 47, "Accounting for Conditional Asset Retirement Obligations."

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. See Note 14 of the Notes to Consolidated Financial Statements, "Asset Retirement Obligations," for additional detail of our asset retirement obligations.

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 15 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 for the sale of such energy that have yet to settle.

Market-based wholesale: Includes: (i) sales of energy to wholesale customers, the rates for which are generally based on prevailing market prices as allowed by FERC approved market-based tariffs, or where not permitted, pricing is based on incremental cost plus a permitted margin and (ii) changes in valuations for contracts for the sale of such 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; (iii) fees we earn for marketing services that we provide for third parties; and (iv) changes in valuations for contracts related to such transactions that have yet to settle.

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. 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. 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.

2008 Compared to 2007

Below we discuss our operating results for the year ended December 31, 2008, compared to the results for the year ended December 31, 2007. Changes in results of operations are as follows.

Year Ended December 31,	2008	2007	Change	% Change
	(In Thousands, Except Per Share Amounts)			
SALES:				
Residential	$ 516,926	$ 491,163	$25,763	5.2
Commercial	485,016	448,368	36,648	8.2
Industrial	291,863	264,566	27,297	10.3
Other retail	(6,093)	(18,133)	12,040	66.4
Total Retail Sales	1,287,712	1,185,964	101,748	8.6
Tariff-based wholesale	239,693	218,647	21,046	9.6
Market-based wholesale	174,116	161,796	12,320	7.6
Energy marketing	14,521	36,978	(22,457)	(60.7)
Transmission[a]	98,549	97,717	832	0.9
Other	24,405	25,732	(1,327)	(5.2)
Total Sales	1,838,996	1,726,834	112,162	6.5
OPERATING EXPENSES:				
Fuel and purchased power	694,348	544,421	149,927	27.5
Operating and maintenance	471,838	473,525	(1,687)	(0.4)
Depreciation and amortization	203,738	192,910	10,828	5.6
Selling, general and administrative	184,427	178,587	5,840	3.3
Total Operating Expenses	1,554,351	1,389,443	164,908	11.9
INCOME FROM OPERATIONS	284,645	337,391	(52,746)	(15.6)
OTHER INCOME (EXPENSE):				
Investment (loss) earnings	(10,453)	6,031	(16,484)	(273.3)
Other income	29,658	6,726	22,932	340.9
Other expense	(15,324)	(14,072)	(1,252)	(8.9)
Total Other Income (Expense)	3,881	(1,315)	5,196	395.1
Interest expense	106,450	103,883	2,567	2.5
INCOME BEFORE INCOME TAXES	182,076	232,193	(50,117)	(21.6)
Income tax expense	3,936	63,839	(59,903)	(93.8)
NET INCOME	178,140	168,354	9,786	5.8
Preferred dividends	970	970	—	—
EARNINGS AVAILABLE FOR COMMON STOCK	$ 177,170	$ 167,384	$ 9,786	5.8
BASIC EARNINGS PER SHARE	$ 1.70	$ 1.85	$ (0.15)	(8.1)

[a] ***Transmission:*** *Includes an SPP network transmission tariff. In 2008, our SPP network transmission costs were $77.9 million. This amount, less $6.7 million retained by the SPP as administration cost, was returned to us as revenue. In 2007, our SPP network transmission costs were $82.0 million with an administration cost of $9.2 million retained by the SPP.*

The following table reflects changes in electric sales volumes, as measured by thousands of 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,	2008	2007	Change	% Change
	(Thousands of MWh)			
Residential	6,494	6,677	(183)	(2.7)
Commercial	7,363	7,537	(174)	(2.3)
Industrial	5,769	5,819	(50)	(0.9)
Other retail	88	91	(3)	(3.3)
Total Retail	19,714	20,124	(410)	(2.0)
Tariff-based wholesale	6,176	6,360	(184)	(2.9)
Market-based wholesale	3,208	3,666	(458)	(12.5)
Total	29,098	30,150	(1,052)	(3.5)

Notwithstanding a 2% decrease in MWh sales volumes, retail sales were $101.7 million higher for the year ended December 31, 2008, due principally to our prices including higher fuel and purchased power costs. Residential, commercial and industrial sales increased a combined $89.7 million primarily because fuel costs reflected in the RECA were $114.3 million higher compared to last year. Partially offsetting the higher revenues attributable to the RECA was the effect of cooler weather. As measured by cooling degree days, the weather during 2008 was 20% cooler than during 2007. The $12.0 million change in other retail sales is due primarily to decreases in refund obligations compared to last year.

Tariff-based wholesale sales were $21.0 million higher than last year attributable principally to a 13% higher average price per MWh for these sales compared to last year. The higher average price was the result of including higher fuel costs in the prices we charge. Partially offsetting the higher average price per MWh was a 3% decrease in sales volumes due primarily to the expiration of wholesale contracts.

Market-based wholesale sales increased $12.3 million compared to last year due principally to a 12% higher average price for these sales compared to last year. Partially offsetting the higher average price was a 12% decrease in sales volumes attributable primarily to our having less production available due to extended outages at some of our lower cost base load plants during 2008.

Energy marketing decreased $22.5 million compared to the previous year due to several factors. Among them were: the need to focus resources toward serving our retail customers during our extended outages, changes in the relationships of prices among energy products historically traded and the continuing maturation of the energy markets in which we participate reducing margin opportunities. A notable trend is that more transactions are being completed through RTO-sponsored markets as opposed to negotiated transactions directly between counterparties. While this trend is expected to continue, we are unable to determine how all of the aforementioned factors may affect energy marketing in the future. Contributing to the decrease was the recognition of a $3.2 million customer refund obligation and the recognition of a $3.0 million obligation related to claims made by an independent system operator seeking the re-pricing of transactions conducted within that operator's region in prior periods.

Fuel and purchased power expense increased $149.9 million compared to last year. The change in fuel and purchased power expense resulted from a number of factors, including: the volumes of power we produced and purchased, prevailing market prices and contract provisions that allow for price changes. Fuel used for generation increased $73.3 million, or 15%, stemming primarily from outages at our lower cost, base load plants that caused us to rely more heavily on our plants that require more expensive fuels. When compared to the year ended December 31, 2007, we used 5% less fuel by volume this year, in part because of greater purchases of power from others. Because some of our plants that use the least expensive fuels (i.e. nuclear and coal) were not producing at times due to outages, we had the choice of either producing the needed volumes at plants that are more expensive to operate or acquiring those volumes from others. Generally, purchasing power from others was the more economical alternative, and as a result, our purchased power expense increased $31.4 million, reflecting a 34% increase in such volumes. For almost all retail customers, the cost of fuel and purchased power we incur that is in excess of costs recovered in rates is deferred as a regulatory asset until the costs are recovered. For the year ended December 31, 2008, we recovered $13.4 million for fuel expense previously deferred compared to deferring $26.7 million of fuel expense during the year ended December 31, 2007.

Depreciation and amortization expense increased $10.8 million compared to last year due to depreciation expense associated with a higher plant balance.

The $5.8 million increase in selling, general and administrative expense was due primarily to a $3.2 million increase in legal costs. Various court orders require that we pay legal fees incurred by two former executive officers related to the defense of criminal charges filed against them by the United States Attorneys' Office. Higher legal expenses were also related to more regulatory activities. Also contributing to the increase was $3.9 million in additional labor costs and a $1.4 million increase in bad debt expense. Offsetting these increases was a $5.0 million decrease in employee benefits expense.

Investment earnings decreased $16.5 million compared to last year due primarily to our having recorded a $10.9 million loss on investments held in a trust used to fund retirement benefits. We recorded a $4.8 million gain on these investments for the prior year.

Other income increased $22.9 million compared to last year due primarily to our having recorded $18.3 million of equity allowance for funds used during construction (AFUDC) this year compared to $4.3 million of equity AFUDC recorded last year. Also contributing to the increase was a $4.8 million gain on the sale of oil in 2008. In addition, we recorded $5.8 million of corporate-owned life insurance (COLI) benefit this year compared to $0.7 million of COLI benefit recorded last year.

Interest expense increased $2.6 million compared to last year due primarily to interest on additional debt issued to fund investments in capital equipment. Partially offsetting this increase was the reversal of $17.8 million of accrued interest associated with uncertain tax liabilities during 2008.

Income tax expense decreased $59.9 million compared to last year due to the recognition of $28.7 million of previously unrecognized tax benefits and the recognition of $14.6 million in state tax incentives related to investment and jobs creation within the state of Kansas.

2007 Compared to 2006

Below we discuss our operating results for the year ended December 31, 2007, compared to the results for the year ended December 31, 2006. Changes in results of operations are as follows.

Year Ended December 31,	2007	2006	Change	% Change
	(In Thousands, Except Per Share Amounts)			
SALES:				
Residential	$ 491,163	$ 486,107	$ 5,056	1.0
Commercial	448,368	438,342	10,026	2.3
Industrial	264,566	266,922	(2,356)	(0.9)
Other retail	(18,133)	(32,098)	13,965	43.5
Total Retail Sales	1,185,964	1,159,273	26,691	2.3
Tariff-based wholesale	218,647	195,428	23,219	11.9
Market-based wholesale	161,796	105,768	56,028	53.0
Energy marketing	36,978	35,562	1,416	4.0
Transmission[a]	97,717	83,764	13,953	16.7
Other	25,732	25,948	(216)	(0.8)
Total Sales	1,726,834	1,605,743	121,091	7.5
OPERATING EXPENSES:				
Fuel and purchased power	544,421	483,959	60,462	12.5
Operating and maintenance	473,525	463,785	9,740	2.1
Depreciation and amortization	192,910	180,228	12,682	7.0
Selling, general and administrative	178,587	171,001	7,586	4.4
Total Operating Expenses	1,389,443	1,298,973	90,470	7.0
INCOME FROM OPERATIONS	337,391	306,770	30,621	10.0
OTHER INCOME (EXPENSE):				
Investment earnings	6,031	9,212	(3,181)	(34.5)
Other income	6,726	18,000	(11,274)	(62.6)
Other expense	(14,072)	(13,711)	(361)	(2.6)
Total Other (Expense) Income	(1,315)	13,501	(14,816)	(109.7)
Interest expense	103,883	98,650	5,233	5.3
INCOME BEFORE INCOME TAXES	232,193	221,621	10,572	4.8
Income tax expense	63,839	56,312	7,527	13.4
NET INCOME	168,354	165,309	3,045	1.8
Preferred dividends	970	970	—	—
EARNINGS AVAILABLE FOR COMMON STOCK	$ 167,384	$ 164,339	$ 3,045	1.9
BASIC EARNINGS PER SHARE	$ 1.85	$ 1.88	$ (0.03)	(1.6)

[a] ***Transmission:*** *Includes an SPP network transmission tariff. In 2007, our SPP network transmission costs were $82.0 million. This amount, less $9.2 million that was retained by the SPP as administration cost, was returned to us as revenue. In 2006, our SPP network transmission costs were $76.0 million with an administration cost of $10.1 million retained by the SPP.*

The following table reflects changes in electric sales volumes, as measured by thousands of 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,	2007	2006	Change	% Change
	(Thousands of MWh)			
Residential	6,677	6,456	221	3.4
Commercial	7,537	7,185	352	4.9
Industrial	5,819	5,824	(5)	(0.1)
Other retail	91	93	(2)	(2.2)
Total Retail	20,124	19,558	566	2.9
Tariff-based wholesale	6,360	5,505	855	15.5
Market-based wholesale	3,666	1,913	1,753	91.6
Total	30,150	26,976	3,174	11.8

Retail sales were $26.7 million higher for the year ended December 31, 2007, due principally to increases in other retail, commercial and residential sales. Other retail sales increased $14.0 million due primarily to decreases in refund obligations. Commercial and residential sales increased a combined $15.1 million due primarily to cooler weather during the winter months and customer growth in our service territory. When measured by heating degree days, the weather during 2007 was 16% cooler than during 2006.

Tariff-based wholesale sales were $23.2 million higher in 2007 than in 2006 due principally to increased sales volumes that were primarily the result of additional sales from the long-term sale agreement entered into in 2007 with Mid-Kansas Electric Company, LLC. The average price per MWh for these sales, however, was about 3% lower in 2007 than in 2006.

Market-based wholesale sales were $56.0 million higher in 2007 than in 2006 due principally to increased sales volumes that were primarily the result of coal conservation efforts and a scheduled refueling outage at Wolf Creek, both of which occurred in 2006 and did not recur in 2007. The average price per MWh for these sales, however, was about 13% lower in 2007 than in 2006.

Fuel and purchased power expense increased $60.5 million in 2007 compared to 2006. The change in fuel and purchased power expense resulted from a number of factors, including: the volumes of power we produced and purchased, prevailing market prices and contract provisions that allow for price changes. We used 12% more fuel in our generating plants in 2007, due primarily to our not having had to conserve coal this year as we did in 2006. This resulted in $53.6 million higher fuel expense compared with 2006. Purchased power expense increased $6.8 million over 2006 due primarily to higher prices, but were largely offset by a 4% reduction in purchased volumes. In 2007 through the RECA, we deferred for future recovery $26.7 million of fuel and purchased power costs as a regulatory asset compared with $6.9 million in 2006.

Operating and maintenance expense increased $9.7 million in 2007 compared to 2006. This was due primarily to higher maintenance costs of $8.7 million for our power plants, electrical distribution system and transmission system and a $6.0 million increase in SPP network transmission costs that are in large part recovered through higher transmission revenues.

Depreciation and amortization expense increased $12.7 million in 2007 compared to 2006. This was due principally to depreciation expense associated with a higher plant balance including the capital lease associated with the purchase of Aquila Inc.'s (Aquila) 8% leasehold interest in Jeffrey Energy Center.

Selling, general and administrative expense increased $7.6 million due primarily to a $6.2 million increase in employee benefit costs and a $6.0 million increase in labor costs. These increases were partially offset by reduced legal fees associated with matters having to deal with former management.

Other income decreased $11.3 million in 2007 compared to 2006 due primarily to our having recorded $0.7 million in proceeds from COLI in 2007 compared to $16.4 million in COLI proceeds recorded in 2006. Partially offsetting this decrease was the recording of $4.3 million of equity AFUDC for 2007, which compares to no equity AFUDC recorded for 2006.

Income tax expense increased $7.5 million in 2007 compared to 2006 due primarily to decreases in the utilization of previously unrecognized capital loss carryforwards to offset realized capital gains and decreases in non-taxable income from COLI. The increase was partially offset by increased tax benefits from the utilization of a net operating loss that had not previously been applied against income for other carryback or carryover years.

FINANCIAL CONDITION

A number of factors affected amounts recorded on our balance sheet as of December 31, 2008, compared to December 31, 2007.

Given unprecedented uncertainty in capital markets and concerns about how well the banking industry may function amidst the turmoil, we decided to increase cash holdings to allow for additional flexibility, resulting in an increase in cash and cash equivalents of $17.2 million over last year.

Inventories and supplies increased $11.8 million due primarily to a $17.1 million increase related to new facilities and large construction projects. Upward adjustments to some of our coal contracts and increased freight costs together contributed to a $6.5 million increase in coal inventory. Increases were partially offset by the sale of $13.0 million of oil.

The fair market value of energy marketing contracts increased $8.9 million to $50.4 million at December 31, 2008. This was due primarily to favorable changes in market values of contracts outstanding throughout 2008, in addition to contracts entered into in 2008.

Tax receivable decreased $34.6 million due primarily to receipt of a tax refund and the settlement of the IRS audit of tax years 1995 through 2002.

Regulatory assets, net of regulatory liabilities, increased $295.4 million to $829.2 million at December 31, 2008, from $533.8 million at December 31, 2007. Total regulatory assets increased $276.8 million due primarily to the fair market value of employee benefit plan assets decreasing. We recognize as a regulatory asset or regulatory liability the difference between the fair value of pension and post-retirement benefit plan assets and the liabilities for our pension and post-retirement benefit plans. The significant decline in the value of pension assets in 2008 resulted in a $237.5 million increase in regulatory assets. Further increasing regulatory assets was $39.8 million of additional net deferred future income taxes. Total regulatory liabilities decreased $18.6 million due primarily to a $36.7 million decrease in the fair value of the nuclear decommissioning trust largely offset by a $24.9 million increase in removal costs for amounts collected and not yet spent to remove retired assets.

Other long-term assets decreased $7.5 million due primarily to a $10.9 million decrease in the fair value of assets held in a trust used to fund retirement benefits.

Other current liabilities increased $14.3 million due primarily to declaring dividends on a greater number of shares in 2008.

Long-term debt, net of current maturities, increased $302.8 million due principally to the issuance of $450.0 million of first mortgage bonds as discussed in detail in Note 9 of the Notes to Consolidated Financial Statements, "Long-Term Debt." The increase was partially offset by the reclassification of $145.1 million of long-term debt due August 1, 2009, to current maturities.

Other long-term liabilities decreased $62.3 million due primarily to a $39.4 million decrease in uncertain tax liabilities and related accrued interest. See Note 10 of the Notes to Consolidated Financial Statements, "Taxes."

Common stock and paid-in capital increased $305.5 million due principally to the issuance of common stock as discussed in Note 17 of the Notes to the Consolidated Financial Statements, "Common and Preferred Stock."

LIQUIDITY AND CAPITAL RESOURCES

Overview

Available sources of funds to operate our business include internally generated cash, Westar Energy's revolving credit facility and access to capital markets. We expect to meet our day-to-day cash requirements including, among others, fuel and purchased power, dividends, interest payments, income taxes and pension contributions, primarily using internally generated cash and borrowings under the revolving credit facility. To meet the cash requirements for our capital investments, we expect to use internally generated cash, borrowings under the revolving credit facility and the issuance of debt and equity securities in the capital markets. We also use the proceeds from the issuance of securities to repay borrowings under the revolving credit facility, with those borrowed amounts principally related to our investments in capital equipment, and for working capital and general corporate purposes. The aforementioned sources and uses of cash are similar to our historical activities with a significant increase in cash requirements for our capital investments. For additional information on our future cash requirements, see "— Future Cash Requirements" below.

In the latter part of 2008, capital markets experienced unprecedented volatility and dramatic declines in asset valuations. As a result, capital is more costly and more difficult to obtain. In light of the current volatility and the unpredictability of how long these capital market conditions will persist, we have reduced or delayed construction spending and other capital outlays in order to manage liquidity. Additionally, this volatility, accompanied by reduced asset values,

will require us to make additional contributions to the Westar Energy pension trust and to increase our funding of the Wolf Creek pension trust. See "— Pension Obligation" below for additional information. We do not expect the previously mentioned economic conditions to impact our ability to pay dividends. Uncertainties affecting our ability to meet cash requirements include, among others: factors affecting sales described in "— Operating Results" above, economic conditions, regulatory actions, compliance with environmental regulations and conditions in the capital markets.

Capital Resources

As of December 31, 2008, we had $22.9 million in unrestricted cash and cash equivalents. On January 11, 2008, we filed a request with FERC for authority to issue short-term securities and to pledge KGE mortgage bonds in order to increase the size of Westar Energy's revolving credit facility from $500.0 million to $750.0 million. On February 15, 2008, FERC granted our request and on February 22, 2008, a syndicate of banks in the credit facility increased their commitments to $750.0 million in the aggregate. Effective February 22, 2008, $730.0 million of the commitments of the lenders under the revolving credit facility terminate on March 17, 2012. The remaining $20.0 million of the commitments terminate on March 17, 2011.

Lehman Brothers Commercial Paper, Inc. (Lehman Brothers) is the participating lender with respect to a $20.0 million commitment terminating March 17, 2011. On October 5, 2008, Lehman Brothers filed for bankruptcy protection. Under terms of the credit facility, we have the right to replace Lehman Brothers should another lender or lenders be willing to replace the $20.0 million commitment. To date, we have elected not to seek a replacement lender. As a result, until such time as we seek and locate a replacement lender or lenders, the revolving credit facility is limited to $730.0 million. As of February 18, 2009, $230.2 million had been borrowed and an additional $21.1 million of letters of credit had been issued under the revolving credit facility.

A default by Westar Energy or KGE under other indebtedness totaling more than $25.0 million would be 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. At December 31, 2008, our ratio was 54%. 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.

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, 2008, based on an assumed interest rate of 7.50%, approximately $138.0 million principal amount of additional first mortgage bonds could be issued under the most restrictive provisions in the mortgage, except in connection with certain refundings.

The KGE mortgage prohibits additional first mortgage bonds from being issued, except in connection with certain refundings, unless KGE's net earnings before income taxes and before provision for retirement and depreciation of property for a period of 12 consecutive months within 15 months preceding the issuance are not less than either two and one-half times the annual interest charges on, or 10% of the principal amount of, all KGE first mortgage bonds outstanding after giving effect to the proposed issuance. In addition, the issuance of bonds is subject to limitations based on the amount of bondable property additions. As of December 31, 2008, based on an assumed interest rate of 7.50%, approximately $415.0 million principal amount of additional KGE first mortgage bonds could be issued under the most restrictive provisions in the mortgage.

Common Stock Issuance

On May 29, 2008, we entered into an underwriting agreement relating to the offer and sale of 6.0 million shares of the company's common stock. On June 4, 2008, we issued all 6.0 million shares and received $140.6 million in total proceeds, net of underwriting discounts and fees related to the offering.

On November 15, 2007, we entered into a forward sale agreement with a bank, as forward purchaser, relating to 8.2 million shares of our common stock. The forward sale agreement provides for the sale of our common stock within approximately twelve months at a stated settlement price. In connection with the forward sale agreement, the bank borrowed an equal number of shares of our common stock from stock lenders and sold the borrowed shares to another bank under an underwriting agreement among Westar Energy and the banks. The underwriters subsequently offered the borrowed shares to the public at a price per share of $25.25.

On December 28, 2007, we delivered 3.1 million newly issued shares of our common stock to a bank and received proceeds of $75.0 million as partial settlement of the forward sale agreement. Additionally, on February 7, 2008, we delivered 2.1 million shares and received proceeds of $50.0 million as partial settlement of the forward sale agreement. On June 30, 2008, we completed the forward sale agreement by delivering 3.0 million shares and receiving proceeds of $73.0 million.

On August 24, 2007, we entered into a Sales Agency Financing Agreement with a bank. Under the terms of the agreement, we may offer and sell shares of our common stock from time to time through the bank, as agent, up to an aggregate of $200.0 million for a period of no more than three years. We will pay the bank a commission equal to 1% of the sales price of all shares sold under the agreement. During 2007 we sold 0.8 million shares of common stock through the bank for $20.0 million and received $19.8 million in proceeds net of commission. During 2008 we sold 1.1 million shares of common stock through the bank for $26.9 million and received $26.7 million in proceeds net of commission.

On April 12, 2007, we entered into an earlier Sales Agency Financing Agreement with the same bank. As of July 12, 2007, we had sold 3.7 million shares of our common stock for $100.0 million pursuant to the agreement. We received $99.0 million in proceeds net of a commission.

We used the proceeds from the issuance of common stock to repay borrowings under Westar Energy's revolving credit facility, with those borrowed amounts principally related to our investments in capital equipment, as well as for working capital and general corporate purposes.

Cash Flows from Operating Activities

Operating activities provided $274.9 million of cash in the year ended December 31, 2008, compared with cash provided from operating activity of $246.8 million during the same period of 2007. Principal contributors to the increase were additional collections from customers during 2008 due in large part to our having recovered higher fuel costs from customers through the RECA and $109.9 million in lower income tax payments this year compared to last year. Offsetting these increases were: our having paid $53.2 million to restore our electrical system which was severely damaged by an ice storm in December 2007; additional outages occurring this year at our base load plants; our having paid more for fuel and purchased power this year compared to last year; and during 2008, we paid $15.7 million more for our share of Wolf Creek's refueling outage.

Cash flows from operating activities decreased $9.2 million to $246.8 million in 2007, from $256.0 million in 2006. During 2007, as compared to 2006, we paid approximately $48.3 million more for natural gas used in our power plants, $29.8 million more for coal inventory and $29.4 million more in customer refunds. Offsetting these amounts were a $10.1 million reduction in La Cygne unit 2 lease payments, $9.0 million less in voluntary contributions to our pension trust and cash realized from higher gross margins. During 2006, we also used $65.0 million related to the termination of our accounts receivable sales program.

Cash Flows used in 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 $937.2 million in 2008, $748.2 million in 2007 and $344.9 million in 2006 on net additions to utility property, plant and equipment. The increase from 2006 to 2008 is due primarily to environmental projects, wind generation projects, transmission projects and the construction of Emporia Energy Center.

Cash Flows used in Financing Activities

We received net cash flows from financing activities of $648.7 million in 2008. Proceeds from the issuance of long-term debt provided $544.7 million, proceeds from the issuance of common stock provided $293.6 million and borrowings from COLI provided $64.3 million. We used cash to pay $109.6 million in dividends and to retire $101.3 million of long-term debt.

In 2007, we received net cash flows from financing activities of $502.8 million. Proceeds from the issuance of long-term debt provided $322.3 million and proceeds from the issuance of common stock provided $195.4 million. We used cash to pay $89.5 million in dividends.

In 2006, we received net cash flows from financing activities of $12.8 million. 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.

Future Cash Requirements

Our business requires significant capital investments. Through 2011, we expect we will need cash primarily for utility construction programs designed to improve and expand facilities providing electric service, which include but are not limited to expenditures for peaking capacity needs, new transmission lines and for compliance 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.

We have incurred and expect to continue to incur material costs to comply with existing and future environmental laws and regulations, all of which are subject to changing interpretations and amendments. In addition, the current focus on the effect of air emissions on the global environment could result in significantly more stringent laws and regulations or interpretations thereof that could affect our company and industry in particular. These laws, regulations and interpretations could result in more stringent terms in our existing operating permits or a failure to obtain new permits, could cause a material increase in our capital or operational costs and could otherwise have a material effect on our operations.

While we believe we can generally recover environmental costs through rate increases, there is no guarantee that we will be able to do so. In addition, we may be subject to significant fines and penalties in connection with the NSR Investigation and the related DOJ lawsuit or other matters, and such fines and penalties may not be recovered through rate increases.

Capital expenditures for 2008 and anticipated capital expenditures including costs of removal for 2009 through 2011 are shown in the following table.

	Actual 2008	2009	2010	2011
	(In Thousands)			
Generation:				
Replacements and other	$ 110,942	$ 113,700	$ 113,500	$ 117,300
Additional capacity	138,893	39,200	12,300	10,200
Wind generation	130,404	2,200	200,000	—
Environmental	257,218	83,900	235,600	407,800
Nuclear fuel	17,668	23,000	30,100	24,400
Transmission[a]	149,988	132,500	222,800	172,700
Distribution:				
Replacements and other	45,805	40,500	64,100	88,200
New customers	54,360	58,600	61,500	64,300
Other	31,964	7,700	22,400	22,100
Total capital expenditures	$ 937,242	$ 501,300	$ 962,300	$ 907,000

[a] *Includes $9,000 in 2010 and $26,100 in 2011 for expenditures related to Prairie Wind Transmission.*

We prepare these estimates for planning purposes and revise our estimates from time to time. Actual expenditures will differ, perhaps materially, from our estimates due to changing environmental requirements, changing costs, delays in engineering, construction or permitting, changes in the availability and cost of capital, and other factors discussed above in "Item 1A. Risk Factors." We and our generating plant co-owners periodically evaluate these estimates, and this may result in frequent and possibly material changes in actual costs. In addition, these amounts do not include any estimates for expenditures that may be incurred as a result of the NSR Investigation and the related DOJ lawsuit or for potentially new environmental requirements relating to mercury and CO_2 emissions.

Maturities of long-term debt as of December 31, 2008, are as follows.

Year	Principal Amount
	(In Thousands)
2009	$ 146,366
2010	1,345
2011	61
2012	—
Thereafter	2,196,118
Total long-term debt maturities	$2,343,890

Debt Financings

As of December 31, 2008, we had $171.9 million of variable rate, tax-exempt bonds. Interest rates payable under these bonds have historically been set by auctions, which occur every 35 days. During 2008, auctions for these bonds failed, resulting in alternative index-based interest rates for these bonds of between 1% and 14%. On July 31, 2008, the KCC approved our request to remarket or refund all or part of these auction rate bonds, at our discretion. On August 26, 2008, we completed the refunding of $50.0 million of auction rate bonds at a fixed interest rate of 5.60% and a maturity date of June 1, 2031. On October 10, 2008, we completed the refunding of an additional $50.0 million of auction rate bonds at a fixed interest rate of 6.00% and a maturity date of June 1, 2031. We continue to monitor the credit markets and evaluate our options with respect to the remaining auction rate bonds.

On November 25, 2008, Westar Energy issued $300.0 million principal amount of first mortgage bonds at a discount to yield 8.750%, but bearing interest at 8.625%, and maturing on December 1, 2018. We received net proceeds of $295.6 million.

On May 15, 2008, KGE issued $150.0 million principal amount of first mortgage bonds in a private placement transaction with $50.0 million of the principal amount bearing interest at 6.15% and maturing on May 15, 2023, and $100.0 million bearing interest at 6.64% and maturing on May 15, 2038.

In December 2007, we entered into a $1.8 million equipment financing loan agreement with a term of 36 months to finance the cost of certain computer equipment purchased in 2007. In January 2008, we increased the size of this loan by $2.1 million to $3.9 million for equipment purchases made in 2008. As of December 31, 2008, the balance of this loan was $2.7 million.

On October 15, 2007, KGE issued $175.0 million principal amount of 6.53% first mortgage bonds maturing in 2037 in a private placement to an institutional investor.

On May 16, 2007, Westar Energy sold $150.0 million aggregate principal amount of 6.10% Westar Energy first mortgage bonds maturing in 2047.

Proceeds from the issuance of first mortgage bonds were used to repay borrowings under Westar Energy's revolving credit facility, with those borrowed amounts principally related to investments in capital equipment, as well as for working capital and general corporate purposes.

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, 2008.

Credit Ratings

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

S&P upgraded its credit rating for Westar Energy's unsecured debt securities in November 2008 and upgraded its credit rating for Westar Energy's first mortgage bonds/senior secured debt securities in September 2007. In August 2008, Fitch upgraded its credit ratings for Westar Energy's first mortgage bonds/senior secured debt securities and unsecured debt securities as well as KGE's first mortgage bonds/senior secured debt securities. Fitch also changed its outlook for our ratings to stable.

As of February 18, 2009, ratings with these agencies are as shown in the table below.

	Westar Energy First Mortgage Bond Rating	KGE First Mortgage Bond Rating	Westar Energy Unsecured Debt
Moody's	Baa2	Baa2	Baa3
S&P	BBB	BBB	BBB-
Fitch	BBB+	BBB+	BBB

In general, less favorable credit ratings make borrowing more difficult and costly. Under our revolving credit facility our cost of borrowing is determined in part by our credit ratings. However, our ability to borrow under the revolving credit facility is not conditioned on maintaining a particular credit rating. We may enter into new credit agreements that contain credit rating conditions, which could affect our liquidity and/or our borrowing costs.

Factors that impact our credit ratings include a combination of objective and subjective criteria. Objective criteria include typical financial ratios, such as total debt to total capitalization and funds from operations to total debt, among others, future capital expenditures and our access to liquidity including committed lines of credit. Subjective criteria include such items as the quality and credibility of management, the political and regulatory environment we operate in and an assessment of our governance and risk management practices.

Capital Structure

As of December 31, 2008 and 2007, our capital structure excluding short-term debt was as follows:

	2008	2007
Common equity	48%	49%
Preferred stock	<1%	1%
Long-term debt	51%	50%

OFF-BALANCE SHEET ARRANGEMENTS

Forward Equity Transaction

On November 15, 2007, we entered into a forward sale agreement relating to 8.2 million shares of our common stock. The forward sale agreement provided for the sale of our common stock within approximately twelve months at a stated settlement price. On December 28, 2007, we delivered 3.1 million newly issued shares of our common stock to a bank and received proceeds of $75.0 million as partial settlement of the forward sale agreement. Additionally, on February 7, 2008, we delivered 2.1 million shares and received proceeds of $50.0 million as partial settlement of the forward sale agreement. On June 30, 2008, we completed the forward sale agreement by delivering 3.0 million shares of our common stock and receiving proceeds of $73.0 million.

As of December 31, 2008, we did not have any additional 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 18 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, 2008.

Contractual Cash Obligations

The following table summarizes the projected future cash payments for our contractual obligations existing as of December 31, 2008.

	Total	2009	2010-2011	2012-2013	Thereafter
			(In Thousands)		
Long-term debt[a]	$2,343,890	$146,366	$ 1,406	$ —	$2,196,118
Interest on long-term debt[b]	2,454,051	138,763	256,852	256,852	1,801,584
Adjusted long-term debt	4,797,941	285,129	258,258	256,852	3,997,702
Pension and post-retirement benefit expected contributions[c]	76,000	76,000	—	—	—
Capital leases[d]	188,137	17,443	31,897	19,558	119,239
Operating leases[e]	524,257	49,602	93,669	93,287	287,699
Fossil fuel[f]	1,683,980	297,565	514,021	422,329	450,065
Nuclear fuel[g]	381,269	21,268	56,161	57,909	245,931
Unconditional purchase obligations	270,475	174,736	86,536	9,203	—
Unrecognized income tax benefits including interest[h]	2,699	2,699	—	—	—
Total contractual obligations, including adjusted long-term debt	$7,924,758	$924,442	$1,040,542	$859,138	$5,100,636

[a] *See Note 9 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, 2008.*

[c] *Pension and post-retirement benefit expected contributions represent the minimum funding requirements under the Employee Retirement Income Securities Act (ERISA) as amended by the Pension Protection Act (PPA), plus additional amounts as deemed fiscally appropriate. These amounts for future periods are not yet known. See Notes 11 and 12 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, including the 8% leasehold interest in Jeffrey Energy Center that was purchased in 2007.*

[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.*

[h] *We have an additional $40.1 million of unrecognized income tax benefits, including interest, that are not included in this table because we cannot reasonably estimate the timing of the cash payments to taxing authorities assuming those unrecognized tax benefits are settled at the amounts recognized pursuant to FIN 48 as of December 31, 2008.*

Commercial Commitments

Our commercial commitments existing as of December 31, 2008, consist of outstanding letters of credit that expire in 2009, some of which automatically renew annually. The letters of credit are comprised of $4.5 million related to our energy marketing and trading activities, $9.9 million related to worker's compensation and $4.4 million related to other operating activities for a total outstanding balance of $18.8 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 restricted share units (RSU) 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 statements of income.

Total unrecognized compensation cost related to RSU awards was $5.8 million as of December 31, 2008. We expect to recognize these costs over a remaining weighted-average period of 1.8 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, 2008, 2007 or 2006.

Pension Obligation

The PPA changed the funding requirements for defined benefit pension plans beginning in 2008. Our pension costs and funding requirements are projected to increase as a result of the overall distressed global financial conditions and the decline in the equity and debt markets. We made voluntary contributions to our pension trust of $15.0 million in 2008 and $11.8 million in 2007. We expect to contribute approximately $51.9 million to our pension trust in 2009, of which $12.9 million is required and $39.0 million is voluntary. In 2008 and 2007, we also funded $5.5 million and $5.3 million, respectively, of Wolf Creek's pension trust. In 2009, we are required to fund $4.4 million of Wolf Creek's pension trust and we expect to also voluntarily fund $7.4 million. Future contributions will be based on the minimum funding required by law, plus additional amounts as determined fiscally appropriate for the company and the plans' funded positions. See Notes 11 and 12 of the Notes to Consolidated Financial Statements, "Employee Benefit Plans" and "Wolf Creek Employee Benefit Plans," for additional discussion of Westar Energy and Wolf Creek benefit plans, respectively.

Customer Refunds and Rebates

We refunded to customers $39.4 million in 2007 related to the remand of the December 28, 2005, KCC Order (2005 KCC Order). We also made rebates to customers of $10.0 million during the year ended December 31, 2006, in accordance with a July 25, 2003, KCC Order.

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, 2008, we had recorded regulatory assets currently subject to recovery in future rates of approximately $952.3 million and regulatory liabilities of $123.1 million as discussed in greater detail in Note 2 of the Notes to Consolidated Financial Statements, "Summary of Significant Accounting Policies — Regulatory Accounting." We believe that it is probable that our regulatory assets will be recovered in the future.

Asset Retirement Obligations

Legal Liability

In accordance with SFAS No. 143 and 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 initially recorded asset retirement obligations at fair value for the estimated cost to decommission Wolf Creek (our 47% share), dispose of asbestos insulating material at our power plants, remediate ash disposal ponds and dispose of polychlorinated biphenyl (PCB) contaminated oil.

As of December 31, 2008 and 2007, we have recorded asset retirement obligations of $95.1 million and $88.7 million, respectively. For additional information on our legal asset retirement obligations, see Note 14 of the Notes to Consolidated Financial Statements, "Asset Retirement Obligations."

Non-Legal Liability — Cost of Removal

We recover in rates the costs to dispose of utility plant assets that do not represent legal retirement obligations. As of December 31, 2008 and 2007, we had $50.1 million and $25.2 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.

New Accounting Pronouncements

FSP No. EITF 03-6-1 — Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities

In June 2008, FASB released Staff Position (FSP) No. Emerging Issues Task Force (EITF), 03-6-1, "Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities." FSP No. EITF 03-6-1 provides that all outstanding unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents are participating securities and shall be included in the computation of earnings per share pursuant to the two-class method. FSP No. EITF 03-6-1 is effective for fiscal years beginning after December 15, 2008. We do not expect the adoption of this guidance to have a material impact on our earnings per share.

SFAS No. 161 — Disclosures about Derivative Instruments and Hedging Activities

In March 2008, FASB released SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities — An Amendment of FASB Statement No. 133", which requires expanded disclosure intended to help investors better understand how derivative instruments and hedging activities affect an entity's financial position, financial performance and cash flows. SFAS No. 161 amends and expands our disclosure requirements related to SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" by requiring qualitative disclosure about objectives and strategies for using derivatives, quantitative disclosure about fair value amounts of gains and losses on derivative instruments, and

disclosures about credit-risk-related contingent features in derivative agreements. SFAS No. 161 is effective for fiscal years beginning after November 15, 2008.

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

In February 2007, 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 must report unrealized gains and losses on items for which the 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, with the cumulative effect of the change in accounting principle recorded as an adjustment to opening retained earnings. We adopted the guidance effective January 1, 2008. The adoption of SFAS No. 159 did not have a material impact 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. In February 2008, FASB issued FSP 157-2 which delays the effective date of SFAS No. 157 for all non-financial assets and liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), until fiscal years beginning after November 15, 2008, and interim periods within those fiscal years. The non-financial items subject to the deferral include assets and liabilities such as non-financial assets and liabilities assumed in a business combination, reporting units measured at fair value in a goodwill impairment test and asset retirement obligations initially measured at fair value. We adopted SFAS No. 157 for financial assets and liabilities recognized at fair value on a recurring basis effective January 1, 2008. The adoption of SFAS No. 157 did not have a material impact on our consolidated financial statements. See Note 4 of the Notes to Consolidated Financial Statements, "Financial and Derivative Instruments, Energy Marketing and Risk Management."

Allowance for Funds Used During Construction

AFUDC represents the cost of capital used to finance utility construction activity. AFUDC is computed by applying a composite rate to qualified construction work in progress. The amount of AFUDC capitalized as a construction cost is credited to other income (for equity funds) and interest expense (for borrowed funds) on the accompanying consolidated statements of income, as follows:

Year Ended December 31,	2008	2007	2006
		(In Thousands)	
Borrowed funds	$ 20,536	$ 13,090	$ 4,053
Equity funds	18,284	4,346	—
Total	$ 38,820	$ 17,436	$ 4,053
Average AFUDC Rates	6.4%	6.6%	5.3%

We expect both AFUDC for borrowed funds and equity funds to fluctuate over the next several years as we add generating capacity, expand our transmission system and make significant environmental improvements.

Interest Expense

We expect interest expense to increase significantly over the next several years as we issue new debt securities to fund our capital expenditures program. We believe the increase in interest expense will be recovered from our customers in future rate proceedings.

Wholesale Sales Margins

Previously, the terms of the RECA required that we include, as a credit to recoverable fuel costs beginning in April of each year, an amount based on the average of the margins realized from market-based wholesale sales during the immediately prior three-year period ending June 30. As a result of the 2009 KCC Order, the amount to be credited back to retail customers, beginning approximately March 1, 2009, will be based on the actual margins realized from market-based wholesale sales.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our fuel procurement and energy marketing activities involve primary market risk exposures, including commodity price risk, credit risk and interest rate risk. Commodity price risk is the potential adverse price impact related to the purchase or sell of electricity and fuel procurement for our generating units. Credit risk is the potential adverse financial impact resulting from non-performance by a counterparty of its contractual obligations. Interest rate risk is the potential adverse financial impact related to changes in interest rates.

Market Price Risks

We engage in physical and financial trading activities with the goals of reducing risk from market fluctuations, enhancing system reliability and increasing profits. We procure and trade electricity, coal, natural gas and other energy related products by utilizing energy commodity contracts and a variety of financial instruments, including forward and futures contracts, options and swaps.

Prices in the wholesale power markets often are extremely volatile. This volatility impacts our cost 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 attempt to purchase power from others. Such supplies are not always available. In addition, congestion on the transmission system can limit our ability to make purchases from (or sell into) the wholesale markets. The inability to make wholesale purchases may require that we interrupt or curtail services to our customers. 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 changes in market prices. 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. The availability and deliverability of generating fuel, including fossil and nuclear fuels, can vary significantly from one period to the next. Our customers' electricity usage could also vary from year to year based on the weather or other factors. The loss

of revenues or higher costs associated with such conditions could be material and adverse to our consolidated financial statements. Our risk of loss is mitigated through the use of the RECA and similar adjustment mechanisms that we maintain for many of our wholesale sales contracts and tariffs.

Hedging Activity

In an effort to mitigate market risk associated with fuel procurement and energy marketing, we may use economic hedging arrangements to reduce our exposure to price changes. We may use physical contracts and financial derivative instruments to hedge the price of a portion of our anticipated fossil fuel needs or excess generation sales. At the time we enter into these transactions, we are unable to determine the hedge value until the agreements are actually settled. 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.

Commodity Price Exposure

We manage and measure the market price risk exposure of our trading portfolio using a variance/covariance value-at-risk (VaR) model. 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 2009. The use of VaR requires assumptions, including the selection of a confidence level for potential losses and the estimated holding period. We express VaR as a potential dollar loss based on a 95% confidence level using a one-day holding period. It is possible that actual results may differ markedly from assumptions. Accordingly, VaR may not accurately reflect our levels of exposures. The energy trading and market-based wholesale portfolio VaR amounts for 2008 and 2007 were as follows:

	2008	2007
	(In Thousands)	
High	$1,660	$1,966
Low	127	176
Average	983	639

We have considered a variety of risks and costs associated with the future contractual commitments included in our trading portfolios. These risks include valuation and marking of illiquid pricing locations and products, the financial condition of our counterparties and interest rate movement. See the credit risk and interest rate exposure discussions below for additional information. Also, there can be no assurance that the employment of VaR, credit practices or other risk management tools we employ will eliminate possible losses.

Credit Risk

We have exposure to counterparty default risk with our retail, wholesale and energy marketing activities, including participation in RTOs. We maintain credit policies intended to reduce overall credit risk. We employ additional credit risk control mechanisms that we believe are appropriate, such as requiring counterparties to issue letters of credit or parental guarantees in our favor and entering into master netting agreements with counterparties that allow for offsetting exposures.

Interest Rate Exposure

We have entered into numerous fixed and variable rate debt obligations. For details, see Note 9 of the Notes to Consolidated Financial Statements, "Long-Term Debt." We manage our interest rate risk related to these debt obligations by limiting our variable interest rate exposure and utilizing various maturity dates. We may also use swaps or other financial instruments to manage our interest rate risk. 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 $493.2 million of variable rate debt and current maturities of fixed rate debt as of December 31, 2008. A 100 basis point change in interest rates applicable to this debt would impact income before income taxes on an annualized basis by approximately $4.0 million. As of December 31, 2008, we had $171.9 million of variable rate bonds insured by bond insurers. Interest rates payable under these bonds are set at periodic auctions. Conditions in the credit markets have caused the demand for auction bonds to decline generally and have caused our borrowing costs to increase. Additionally, should those bond insurers experience a decrease in credit rating, such event would most likely increase our borrowing costs as well. 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, 2008, investments by the nuclear decommissioning trust fund were allocated 64% to equity securities, 26% to debt securities, 7% to real estate, 2% to commodities and 1% to cash and cash equivalents. The fair value of these funds was $85.6 million as of December 31, 2008, and $122.3 million as of December 31, 2007. We also maintain a trust that is used to fund retirement benefits. As of December 31, 2008, these funds were comprised of 51% equity securities, 36% debt securities and 13% cash and cash equivalents. The fair value of these funds was $26.3 million as of December 31, 2008, and $37.1 million as of December 31, 2007. By maintaining diversified portfolios of securities, we seek to maximize the returns to fund these obligations within acceptable risk tolerances. However, debt and equity securities in the portfolios are exposed to price fluctuations in the capital markets. If the value of the securities diminishes, the cost of funding the obligations rises. We actively monitor the portfolios 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 related to the nuclear decommissioning fund 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, 2008. In making this assessment, we used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control-Integrated Framework. Based on the assessment, we believe that, as of December 31, 2008, our internal control over financial reporting is effective based on those criteria. Our independent registered public accounting firm has issued an audit report on the company's 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 the internal control over financial reporting of Westar Energy, Inc. and subsidiaries (the "Company") as of December 31, 2008, 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, included in the accompanying management's report on internal control over financial reporting. Our responsibility is to express an opinion on 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, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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 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, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, 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, 2008 of the Company and our report dated February 26, 2009 expressed an unqualified opinion on those financial statements and financial statement schedule and included an explanatory paragraph regarding the Company's adoption of a new accounting standard.

/s/ Deloitte & Touche LLP

Kansas City, Missouri
February 26, 2009

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, 2008 and 2007, and the related consolidated statements of income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2008. Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Westar Energy, Inc. and subsidiaries as of December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, 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 10 to the consolidated financial statements, the Company adopted Financial Accounting Standards Board (FASB) Interpretation No. FIN 48, "Accounting for Uncertainty in Income Taxes — an interpretation of FASB Statement No.109" as of January 1, 2007.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2008, 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 26, 2009 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Kansas City, Missouri
February 26, 2009

WESTAR ENERGY, INC. CONSOLIDATED BALANCE SHEETS

As of December 31, (Dollars in Thousands)	2008	2007
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 22,914	$ 5,753
Accounts receivable, net of allowance for doubtful accounts of $4,810 and $5,721, respectively	199,116	195,785
Inventories and supplies, net	204,297	192,533
Energy marketing contracts	131,647	57,702
Taxes receivable	36,462	71,111
Deferred tax assets	16,416	—
Prepaid expenses	33,419	31,576
Regulatory assets	79,783	98,204
Other	19,077	15,015
Total Current Assets	743,131	667,679
PROPERTY, PLANT AND EQUIPMENT, NET	5,533,521	4,803,672
OTHER ASSETS:		
Regulatory assets	872,487	577,256
Nuclear decommissioning trust	85,555	122,298
Energy marketing contracts	25,601	34,088
Other	182,964	190,437
Total Other Assets	1,166,607	924,079
TOTAL ASSETS	$7,443,259	$ 6,395,430
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Current maturities of long-term debt	$ 146,366	$ 558
Short-term debt	174,900	180,000
Accounts payable	195,683	278,299
Accrued taxes	44,008	47,370
Energy marketing contracts	104,622	42,641
Accrued interest	42,142	41,416
Deferred tax liabilities	—	2,310
Regulatory liabilities	31,123	32,932
Other	133,565	119,237
Total Current Liabilities	872,409	744,763
LONG-TERM LIABILITIES:		
Long-term debt, net	2,192,538	1,889,781
Obligation under capital leases	117,909	123,854
Deferred income taxes	1,004,920	897,293
Unamortized investment tax credits	59,386	59,619
Deferred gain from sale-leaseback	114,027	119,522
Accrued employee benefits	526,177	283,924
Asset retirement obligations	95,083	88,711
Energy marketing contracts	2,262	7,647
Regulatory liabilities	91,934	108,685
Other	155,612	217,927
Total Long-Term Liabilities	4,359,848	3,796,963
COMMITMENTS AND CONTINGENCIES (SEE NOTES 13 AND 15)		
TEMPORARY EQUITY (See Note 11)	3,422	5,224
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 108,311,135 shares and 95,463,180 shares, respectively	541,556	477,316
Paid-in capital	1,326,391	1,085,099
Retained earnings	318,197	264,477
Accumulated other comprehensive income, net	—	152
Total Shareholders' Equity	2,207,580	1,848,480
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$7,443,259	$ 6,395,430

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

WESTAR ENERGY, INC. CONSOLIDATED STATEMENTS OF INCOME

Year Ended December 31, (Dollars in Thousands, Except Per Share Amounts)	2008	2007	2006
SALES	**$ 1,838,996**	$ 1,726,834	$ 1,605,743
OPERATING EXPENSES:			
Fuel and purchased power	**694,348**	544,421	483,959
Operating and maintenance	**471,838**	473,525	463,785
Depreciation and amortization	**203,738**	192,910	180,228
Selling, general and administrative	**184,427**	178,587	171,001
Total Operating Expenses	**1,554,351**	1,389,443	1,298,973
INCOME FROM OPERATIONS	**284,645**	337,391	306,770
OTHER INCOME (EXPENSE):			
Investment (loss) earnings	**(10,453)**	6,031	9,212
Other income	**29,658**	6,726	18,000
Other expense	**(15,324)**	(14,072)	(13,711)
Total Other Income (Expense)	**3,881**	(1,315)	13,501
Interest expense	**106,450**	103,883	98,650
INCOME BEFORE INCOME TAXES	**182,076**	232,193	221,621
Income tax expense	**3,936**	63,839	56,312
NET INCOME	**178,140**	168,354	165,309
Preferred dividends	**970**	970	970
EARNINGS AVAILABLE FOR COMMON STOCK	**$ 177,170**	$ 167,384	$ 164,339
BASIC AND DILUTED EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING (SEE NOTE 2):			
Basic earnings available	**$ 1.70**	$ 1.85	$ 1.88
Diluted earnings available	**$ 1.70**	$ 1.83	$ 1.87
Average equivalent common shares outstanding	**103,958,414**	90,675,511	87,509,800
DIVIDENDS DECLARED PER COMMON SHARE	**$ 1.16**	$ 1.08	$ 1.00

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)	**2008**	2007	2006
NET INCOME	**$ 178,140**	$ 168,354	$ 165,309
OTHER COMPREHENSIVE INCOME (LOSS):			
Unrealized holding gain (loss) on marketable securities arising during the period	—	51	(57)
Minimum pension liability adjustment	—	—	31,841
Other comprehensive income, before tax	—	51	31,784
Income tax expense related to items of other comprehensive income	—	—	(12,666)
Other comprehensive income, net of tax	—	51	19,118
COMPREHENSIVE INCOME	**$ 178,140**	$ 168,405	$ 184,427

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)	2008	2007	2006
CASH FLOWS FROM (USED IN) OPERATING ACTIVITIES:			
Net income	**$ 178,140**	$ 168,354	$ 165,309
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	**203,738**	192,910	180,228
Amortization of nuclear fuel	**14,463**	16,711	13,851
Amortization of deferred gain from sale-leaseback	**(5,495)**	(5,495)	(5,495)
Amortization of corporate-owned life insurance	**18,920**	13,693	15,336
Non-cash compensation	**4,696**	5,800	3,389
Net changes in energy marketing assets and liabilities	**(7,018)**	7,647	(7,505)
Accrued liability to certain former officers	**(1,449)**	931	3,813
Gain on sale of utility plant and property	**(1,053)**	—	(570)
Net deferred income taxes and credits	**35,261**	14,084	(4,203)
Stock based compensation excess tax benefits	**(561)**	(1,058)	(854)
Allowance for equity funds used during construction	**(18,284)**	(4,346)	—
Changes in working capital items, net of acquisitions and dispositions:			
Accounts receivable	**(3,331)**	(15,926)	(55,148)
Inventories and supplies	**(11,764)**	(44,603)	(46,112)
Prepaid expenses and other	**(52,615)**	(72,212)	(4,095)
Accounts payable	**(73,971)**	59,488	22,625
Accrued taxes	**27,938**	(50,027)	(13,160)
Other current liabilities	**(5,732)**	(50,179)	(5,708)
Changes in other assets	**29,389**	(54,668)	19,412
Changes in other liabilities	**(56,382)**	65,712	(25,127)
Cash flows from operating activities	**274,890**	246,816	255,986
CASH FLOWS FROM (USED IN) INVESTING ACTIVITIES:			
Additions to property, plant and equipment	**(937,242)**	(748,156)	(344,860)
Allowance for equity funds used during construction	**18,284**	4,346	—
Investment in corporate-owned life insurance	**(18,720)**	(18,793)	(19,127)
Purchase of securities within the nuclear decommissioning trust fund	**(210,599)**	(240,067)	(345,541)
Sale of securities within the nuclear decommissioning trust fund	**221,613**	238,414	341,410
Proceeds from investment in corporate-owned life insurance	**27,320**	544	22,684
Proceeds from sale of plant and property	**4,295**	—	1,695
Other investing activities	**(11,388)**	—	—
Proceeds from other investments	—	1,653	53,411
Cash flows used in investing activities	**(906,437)**	(762,059)	(290,328)
CASH FLOWS FROM (USED IN) FINANCING ACTIVITIES:			
Short-term debt, net	**(5,100)**	20,000	160,000
Proceeds from long-term debt	**544,715**	322,284	99,662
Retirements of long-term debt	**(101,311)**	(25)	(200,000)
Repayment of capital leases	**(9,820)**	(5,729)	(4,813)
Borrowings against cash surrender value of corporate-owned life insurance	**64,255**	61,472	59,697
Repayment of borrowings against cash surrender value of corporate-owned life insurance	**(28,634)**	(2,209)	(24,133)
Stock based compensation excess tax benefits	**561**	1,058	854
Issuance of common stock, net	**293,621**	195,420	2,394
Cash dividends paid	**(109,579)**	(89,471)	(80,894)
Cash flows from financing activities	**648,708**	502,800	12,767
CASH FLOWS FROM DISCONTINUED OPERATIONS:			
Cash flows from investing activities	**—**	—	1,232
Cash from discontinued operations	**—**	—	1,232
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	**17,161**	(12,443)	(20,343)
CASH AND CASH EQUIVALENTS:			
Beginning of period	**5,753**	18,196	38,539
End of period	**$ 22,914**	$ 5,753	$ 18,196

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	Retained earnings	Accumulated other comprehensive (loss) income	Total Shareholders' Equity
			(Dollars in Thousands)				
Balance at December 31, 2005	$ 21,436	$434,177	$ 923,083	$ (10,257)	$109,987	$ (40,987)	$1,437,439
Net income	—	—	—	—	165,309	—	165,309
Issuance of common stock, net	—	2,797	9,585	—	—	—	12,382
Preferred dividends, net of retirements	—	—	—	—	(970)	—	(970)
Dividends on common stock	—	—	—	—	(88,547)	—	(88,547)
Reclass to Temporary Equity	—	—	(6,671)	—	—	—	(6,671)
Reclass of unearned compensation	—	—	(10,257)	10,257	—	—	—
Amortization of restricted stock	—	—	2,956	—	—	—	2,956
Stock compensation and tax benefit	—	—	(2,091)	—	—	—	(2,091)
Unrealized loss on marketable securities	—	—	—	—	—	(57)	(57)
Minimum pension liability adjustment	—	—	—	—	—	31,841	31,841
Income tax expense	—	—	—	—	—	(12,666)	(12,666)
Reclass to regulatory asset	—	—	—	—	—	21,970	21,970
Balance at December 31, 2006	21,436	436,974	916,605	—	185,779	101	1,560,895
Net income	—	—	—	—	168,354	—	168,354
Issuance of common stock, net	—	40,342	165,623	—	—	—	205,965
Preferred dividends, net of retirements	—	—	—	—	(970)	—	(970)
Dividends on common stock	—	—	—	—	(99,153)	—	(99,153)
Reclass to Temporary Equity	—	—	1,447	—	—	—	1,447
Amortization of restricted stock	—	—	5,116	—	—	—	5,116
Stock compensation and tax benefit	—	—	(3,692)	—	—	—	(3,692)
Unrealized gain on marketable securities	—	—	—	—	—	51	51
Adjustment to Retained Earnings — FIN 48	—	—	—	—	10,467	—	10,467
Balance at December 31, 2007	**21,436**	**477,316**	**1,085,099**	—	**264,477**	**152**	**1,848,480**
Net income	—	—	—	—	**178,140**	—	**178,140**
Issuance of common stock, net	—	**64,240**	**239,316**	—	—	—	**303,556**
Preferred dividends, net of retirements	—	—	—	—	**(970)**	—	**(970)**
Dividends on common stock	—	—	—	—	**(123,107)**	—	**(123,107)**
Reclass to Temporary Equity	—	—	**1,802**	—	—	—	**1,802**
Amortization of restricted stock	—	—	**3,941**	—	—	—	**3,941**
Stock compensation and tax benefit	—	—	**(3,767)**	—	—	—	**(3,767)**
Adjustment to Retained Earnings — SFAS 158	—	—	—	—	**(495)**	—	**(495)**
Adjustment to Retained Earnings — SFAS 159	—	—	—	—	**152**	**(152)**	—
Balance at December 31, 2008	**$ 21,436**	**$ 541,556**	**$1,326,391**	**$ —**	**$ 318,197**	**$ —**	**$2,207,580**

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 679,000 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, reported as a single operating segment, 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, forecasted fuel costs included in our retail energy cost adjustment (RECA) billed to customers, income taxes, pension and other post-retirement and post-employment benefits, our asset retirement obligations including the 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 Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation," and, accordingly, have recorded regulatory assets and liabilities when required by a regulatory order or based on regulatory precedent.

Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery in customer rates. Regulatory liabilities represent probable 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,	2008	2007
	(In Thousands)	
Regulatory Assets:		
Deferred employee benefit costs	$440,061	$202,545
Amounts due from customers for future income taxes, net	193,997	151,279
Debt reacquisition costs	87,321	91,110
Depreciation	85,104	64,665
Ice storm costs	68,109	81,462
Asset retirement obligations	21,542	20,071
Retail energy cost adjustment	17,991	32,794
Disallowed plant costs	16,560	16,650
Wolf Creek outage	12,442	6,984
Other regulatory assets	9,143	7,900
Total regulatory assets	$952,270	$675,460
Regulatory Liabilities:		
Removal costs	$ 50,051	$ 25,157
Fuel supply and capacity sale contracts	36,331	34,042
Nuclear decommissioning	15,054	56,006
Ad valorem tax	7,347	3,846
State Line purchased power	3,379	5,001
Retail energy cost adjustment	456	6,015
Other regulatory liabilities	10,439	11,550
Total regulatory liabilities	$123,057	$141,617

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

- **Deferred employee benefit costs:** Employee benefit costs include $441.2 million, less $2.6 million for applicable taxes, for pension and post-retirement benefit obligations pursuant to 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)" and $1.5 million for post-retirement expenses in excess of amounts paid. We will amortize to expense approximately $26.5 million during 2009 for the benefit obligation. The post-retirement expenses are recovered over a period of five years.
- **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.
- **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.
- **Ice storm costs:** We accumulated and deferred for future recovery costs related to restoring our electric transmission and distribution systems from damage sustained during ice storms. We recover these costs over periods ranging from three to five years. We earn a return on this asset.
- **Asset retirement obligations:** This represents amounts associated with our asset retirement obligations as discussed in Note 14, "Asset Retirement Obligations." We recover this item over the life of the utility plant.
- **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 actual cost of fuel consumed in producing electricity and the cost of purchased power in excess of the amounts we have collected from customers. We expect to recover in our rates this shortfall over a one year period. We have two retail jurisdictions, each of which has a unique RECA and a separate cost of fuel. This can result in our simultaneously reporting both a regulatory asset and a regulatory liability for this item.
- **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.
- **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.
- **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.

- **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.
- **Fuel supply and capacity sale contracts:** We use mark-to-market accounting for some of our fuel supply and capacity sale contracts. This item represents the non-cash net gain position on fuel supply and capacity sale 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 supply 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 held in a decommissioning trust. See Note 5, "Financial Investments and Trading Securities" and Note 14, "Asset Retirement Obligations," for information regarding our Nuclear Decommissioning Trust Fund and our asset retirement obligation.
- **Ad valorem tax:** This represents amounts collected in rates in excess of costs incurred for property taxes. 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.
- **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. We have two retail jurisdictions, each of which has a unique RECA and a separate cost of fuel. This can result in our simultaneously reporting both a regulatory asset and a regulatory liability for this item.
- **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.

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 allowed cost of capital used to finance utility construction activity. We compute AFUDC by applying a composite rate to qualified construction work in progress. We credit to income (for equity funds) and interest expense (for borrowed

funds) the amount of AFUDC capitalized as construction cost on the accompanying consolidated statements of income as follows:

Year Ended December 31,	2008	2007	2006
		(In Thousands)	
Borrowed funds	$ 20,536	$ 13,090	$ 4,053
Equity funds	18,284	4,346	—
Total	$ 38,820	$ 17,436	$ 4,053
Average AFUDC Rates	6.4%	6.6%	5.3%

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 those maintenance costs 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. These rates are based on an average annual composite basis using group rates that approximated 2.6% in 2008 and 2.7% in both 2007 and 2006.

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

	Years
Fossil fuel generating facilities	25 to 75
Nuclear fuel generating facility	40 to 60
Transmission facilities	15 to 65
Distribution facilities	19 to 65
Other	5 to 35

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 $29.3 million as of December 31, 2008, and $36.4 million as of December 31, 2007. Spent nuclear fuel charged to fuel and purchased power expense was $18.3 million in 2008, $21.7 million in 2007 and $18.8 million in 2006.

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 (COLI) policies.

As of December 31,	2008	2007
	(In Thousands)	
Cash surrender value of policies	$ 1,156,457	$ 1,117,828
Borrowings against policies	(1,066,776)	(1,031,155)
Corporate-owned life insurance, net	$ 89,681	$ 86,673

We record as income increases in cash surrender value and death benefits. We offset against policy income the interest expense that we incur on policy loans. Income from death benefits is highly variable from period to period. Death benefits were approximately $9.5 million in 2008, $2.4 million in 2007 and $18.9 million in 2006.

Revenue Recognition — Energy Sales

We record revenue at the time we deliver electricity to customers. We determine the amounts delivered to individual customers through systematic monthly readings of customer meters. At the end of each month, we estimate the electric usage from the last meter read and record the corresponding unbilled revenue.

The accuracy of our unbilled revenue estimate is affected by factors including fluctuations in energy demands, weather, line losses and changes in the composition of customer classes. We had estimated unbilled revenue of $47.7 million as of December 31, 2008, and $43.7 million as of December 31, 2007.

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 a fuel supply contract and a capacity sale contract, which we record as regulatory liabilities, 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. The prices we use to value these transactions reflect our best estimate of the fair value of these contracts. Results actually achieved from these activities could vary materially from intended results and could affect our consolidated financial statements.

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 as required by tax laws and regulatory practices.

As of January 1, 2007, we account for uncertainty in income taxes in accordance with FASB Interpretation No. (FIN) 48. The application of income tax law is complex. Laws and regulations in this area are voluminous and are often ambiguous. Accordingly, we must make subjective assumptions and judgments regarding income tax exposures. Interpretations of and guidance surrounding income tax laws and regulations change over time. As a result, changes in our subjective assumptions and judgments can materially affect amounts we recognize in the consolidated financial statements. See Note 10, "Taxes," for additional detail of our uncertainty in income taxes.

Sales Taxes

We account for the collection and remittance of sales tax on a net basis. As a result, we do not reflect them in our 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 includes 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 physical settlement of a forward sale agreement. We compute the dilutive effect of shares issuable under our stock-based compensation plans and forward sale agreement 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,	2008	2007	2006
DENOMINATOR FOR BASIC AND DILUTED EARNINGS PER SHARE:			
Denominator for basic earnings per share — weighted average equivalent shares	103,958,414	90,675,511	87,509,800
Effect of dilutive securities:			
Employee stock options	728	952	788
Restricted share units	448,314	517,694	589,352
Forward sale agreement	—	66,686	—
Denominator for diluted earnings per share — weighted average equivalent shares	104,407,456	91,260,843	88,099,940
Potentially dilutive shares not included in the denominator because they are antidilutive	21,300	74,890	158,080

Supplemental Cash Flow Information

Year Ended December 31,	2008	2007	2006
		(In Thousands)	
CASH PAID FOR (RECEIVED FROM):			
Interest on financing activities, net of amount capitalized	$102,865	$ 84,291	$ 88,872
Income taxes, net of refunds	(34,905)	74,970	72,407
NON-CASH INVESTING TRANSACTIONS:			
Jeffrey Energy Center 8% leasehold interest	—	118,538	—
Other property, plant and equipment additions	106,219	100,039	29,134
NON-CASH FINANCING TRANSACTIONS:			
Issuance of common stock for reinvested dividends and RSUs	11,263	10,553	10,094
Capital lease for Jeffrey Energy Center 8% leasehold interest	—	118,538	—
Other assets acquired through capital leases	4,583	3,228	4,491

New Accounting Pronouncements

FSP No. EITF 03-6-1 — Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities

In June 2008, FASB released Staff Position (FSP) No. Emerging Issues Task Force (EITF), 03-6-1, "Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities." FSP No. EITF 03-6-1 provides that all outstanding unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents are participating securities and shall be included in the computation of earnings per share pursuant to the two-class method. FSP No. EITF 03-6-1 is effective for fiscal years beginning after December 15, 2008. We do not expect the adoption of this guidance to have a material impact on our earnings per share.

SFAS No. 161 — Disclosures about Derivative Instruments and Hedging Activities

In March 2008, FASB released SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities — An Amendment of FASB Statement No. 133", which requires expanded disclosure intended to help investors better understand how derivative instruments and hedging activities affect an entity's financial position, financial performance and cash flows. SFAS No. 161 amends and expands our disclosure requirements related to SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" by requiring qualitative disclosure about objectives and strategies for using derivatives, quantitative disclosure about fair value amounts of gains and losses on derivative instruments, and disclosures about credit-risk-related contingent features in derivative agreements. SFAS No. 161 is effective for fiscal years beginning after November 15, 2008.

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

In February 2007, 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 must 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, with the cumulative effect of the change in accounting principle recorded as an adjustment to opening retained earnings. We adopted the guidance effective January 1, 2008. The adoption of SFAS No. 159 did not have a material impact 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. In February 2008, FASB issued FSP 157-2 which delays the effective date of

SFAS No. 157 for all non-financial assets and liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), until fiscal years beginning after November 15, 2008, and interim periods within those fiscal years. The non-financial items subject to the deferral include assets and liabilities such as non-financial assets and liabilities assumed in a business combination, reporting units measured at fair value in a goodwill impairment test and asset retirement obligations initially measured at fair value. We adopted SFAS No. 157 for financial assets and liabilities recognized at fair value on a recurring basis effective January 1, 2008. The adoption of SFAS No. 157 did not have a material impact on our consolidated financial statements. See Note 4, "Financial and Derivative Instruments, Energy Marketing and Risk Management."

3. RATE MATTERS AND REGULATION

KCC Proceedings

Changes in Rates

We filed an application with the KCC in May 2008 to increase retail rates by $177.6 million per year. The primary drivers for this application were investments in natural gas generation facilities, wind generation facilities, and other capital projects, costs attributable to the 2007 ice storm, higher operating costs and an update of our capital structure. On October 27, 2008, all parties to the proceeding filed an agreement with the KCC supporting a $130.0 million annual increase in our retail rates. On January 21, 2009, the KCC issued an order approving the settlement agreement and the new retail rates became effective on February 3, 2009.

On July 1, 2008, we implemented an initial retail transmission delivery charge (TDC) on a revenue neutral basis to capture transmission costs ultimately approved in our 2005 general rate case. On September 18, 2008, the KCC granted our request to adjust the TDC to include more recent transmission costs approved by the Federal Energy Regulatory Commission (FERC) and attributable to the retail portion of our transmission service. This served to increase our estimated annual retail revenues by $6.1 million.

On May 29, 2008, the KCC issued an order allowing us to increase our environmental cost recovery rider (ECRR) to include costs associated with investments made in 2007. This change went into effect on June 1, 2008, and served to increase our estimated annual retail revenues by $22.0 million.

On December 28, 2005, the KCC issued the 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 (July 2006 Court Order). The balance of the 2005 KCC Order was upheld.

The Kansas Court of Appeals held: (i) the KCC's approval of a TDC, in the circumstances of this case, violated the Kansas statutes that authorize a TDC, (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 July 2006 Court Order (February 2007 KCC Order). The February 2007 KCC Order: (i) confirmed the original decision regarding treatment of the La Cygne unit 2 sale-leaseback transaction; (ii) reversed the KCC's original decision with regard to the inclusion in depreciation rates of a component for terminal net salvage; and (iii) permits recovery of transmission related costs in a manner similar to how we recover our other costs. On November 30, 2007, we filed with the KCC to implement a separate TDC in a manner consistent with the applicable Kansas statute. The February 2007 KCC Order required us to refund to our customers amounts we collected related to terminal net salvage. On July 31, 2007, the KCC issued an order (July 2007 KCC Order) resolving issues raised by us and interveners following the February 2007 KCC Order. The July 2007 KCC Order: (i) confirmed the earlier decision concerning recovery of terminal net salvage and quantified the effect of that ruling; and (ii) approved a Stipulation and Agreement between us and the KCC Staff. The Stipulation and Agreement approved by the KCC quantified the refund obligation related to amounts previously collected from customers for transmission related costs and established the amount of transmission costs to be included in retail rates, prospectively. Interveners filed petitions for reconsideration of the July 2007 KCC Order on August 15, 2007. These petitions were denied by the KCC on September 13, 2007. The interveners filed appeals with the Kansas Court of Appeals. On February 11, 2008, the Kansas Court of Appeals issued an opinion which affirmed the July 2007 KCC Order. We filed new tariffs and a plan for implementing refunds that became effective on August 29, 2007. Refunds were substantially completed in November.

FERC Proceedings

Requests for Changes in Transmission Rates

On December 2, 2008, FERC issued an order approving a settlement of our transmission formula rate that allows us to include our anticipated transmission capital expenditures for the current year in our transmission formula rate, subject to true up. In addition to the true up, we expect to update our transmission formula rate in January of each year to reflect changes in our projected operating costs and investments.

On March 24, 2008, FERC issued an order that granted our requested incentives of an additional 100 basis points above the base allowed return on equity (ROE) and a 15-year accelerated recovery for an approximately 100 mile, 345 kilovolt (kV) transmission line that will run from near Wichita, Kansas, to near Salina, Kansas. We completed construction of the first segment of this line in December 2008 and expect the second segment to be completed by June 2010. We estimate the line will cost approximately $200.0 million.

In November 2007, we filed applications with FERC that proposed changes in the capital structure used in our transmission formula rate. FERC accepted the proposed changes and the rate change went into effect on June 1, 2007. At December 31, 2008, we had a $2.8 million refund obligation related to this matter, which includes the amount we have collected since June 1, 2007, plus interest on that amount.

On May 2, 2005, we filed applications with FERC that proposed a transmission formula rate providing for annual adjustments to our transmission tariff. This is consistent with our proposals filed with the KCC on May 2, 2005, to charge retail customers separately for transmission service through a TDC. In November 2007, FERC approved a settlement providing for the rate change effective December 1, 2005, and a refund to customers of $3.4 million.

4. FINANCIAL AND DERIVATIVE INSTRUMENTS, ENERGY MARKETING AND RISK MANAGEMENT

Values of Financial and Derivative Instruments

We measure the fair value of each class of our financial and derivative instruments for which it is practicable to measure that value as set forth in SFAS No. 107, "Disclosures about Fair Value of Financial Instruments," and SFAS No. 157, "Fair Value Measurements."

Cash and cash equivalents, short-term borrowings and variable-rate debt are carried at cost, which approximates fair value. The fair value of fixed-rate debt is measured based on quoted market prices for the same or similar issues or on the current rates offered for instruments of the same remaining maturities and redemption provisions. The recorded amounts of accounts receivable and other current financial instruments approximate fair value.

The nuclear decommissioning trust is recorded at fair value using quoted market prices or valuation models utilizing observable market data when available. A portion of the trust assets is comprised of private equity investments or real estate that require significant unobservable market information to measure the fair value of the investments. The private equity investments are initially valued at cost or at the value derived from subsequent financing with adjustments when actual performance differs significantly from expected performance; when market, economic or company-specific conditions change; or when other news or events have a material impact on the security. The real estate investments are valued using market discount rates, projected cash flows and the estimated value into perpetuity. See Note 5, "Financial Investments and Trading Securities," for additional information about investments held within the nuclear decommissioning trust fund.

The fair value of trading securities is measured using quoted market prices or valuation models utilizing observable market data. See Note 5, "Financial Investments and Trading Securities," for additional information about investments classified as trading securities.

Energy marketing contracts can be exchange-traded or over-the-counter (OTC). Fair value measurements of exchange-traded contracts typically utilize quoted prices in active markets. OTC contracts are valued using market transactions and other market evidence whenever possible, including market-based inputs to models, model calibration to market clearing transactions, or alternative pricing sources with reasonable levels of price transparency. Valuation models require a variety of inputs, including contractual terms, market prices, yield curves, credit curves, measures of volatility and correlations of such inputs. Certain OTC contracts trade in less liquid markets with limited pricing information and the determination of fair value for these derivatives is inherently more subjective. In these situations, management estimations are a significant input. See "— Recurring Fair Value Measurements" and "— Derivative Instruments" below for additional information.

We measure fair value based on information available as of December 31, 2008 and 2007. We show the carrying values and measured fair values of our financial instruments in the table below.

	Carrying Value		Fair Value	
As of December 31,	2008	2007	2008	2007
	(In Thousands)			
Fixed-rate debt, net of current maturities[a]	$2,024,178	$1,619,381	$1,749,123	$1,586,407

[a] *This amount does not include an equipment financing loan of $2.7 million and $1.8 million in 2008 and 2007, respectively.*

Recurring Fair Value Measurements

Effective January 1, 2008, we adopted SFAS No. 157, which defines fair value and requires enhanced disclosures about assets and liabilities measured at fair value. SFAS No. 157 establishes a hierarchal framework for disclosing the transparency of the inputs utilized in measuring assets and liabilities at fair value. The three levels defined by the SFAS No. 157 hierarchy and examples of each are as follows:

- Level 1 — Quoted prices are available in active markets for identical assets or liabilities. The types of assets and liabilities included in level 1 are highly liquid and actively traded instruments with quoted prices, such as equities listed on public exchanges and exchange-traded futures contracts.
- Level 2 — Pricing inputs are not quoted prices in active markets, but are either directly or indirectly observable. The types of assets and liabilities included in level 2 are typically either comparable to actively traded securities or contracts, such as treasury securities with pricing interpolated from recent trades of similar securities, or priced with models using highly observable inputs, such as commodity options priced using observable forward prices and volatilities.
- Level 3 — Significant inputs to pricing have little or no transparency. The types of assets and liabilities included in level 3 are those with inputs requiring significant management judgment or estimation, such as the complex and subjective models and forecasts used to determine the fair value of options, real estate investments and long-term fuel supply contracts.

The following table provides the amounts and their corresponding level of hierarchy for our assets and liabilities that are measured at fair value as of December 31, 2008.

	Level 1	Level 2	Level 3	Total
	(In Thousands)			
Assets:				
Energy Marketing Contracts	$ 1,600	$104,821	$ 50,827	$157,248
Nuclear Decommissioning Trust	46,997	30,524	8,034	85,555
Trading Securities[a]	13,420	9,503	—	22,923
Total	$ 62,017	$144,848	$ 58,861	$265,726
Liabilities:				
Energy Marketing Contracts	$ 1,594	$ 99,004	$ 6,286	$106,884

[a] *The total does not include cash and cash equivalents recorded at cost, which are not subject to the fair value requirements set forth in SFAS No. 157.*

We do not offset the fair value of energy marketing contracts executed with the same counterparty. As of December 31, 2008, we have recorded $5.1 million for our right to reclaim cash collateral and $4.5 million for our obligation to return cash collateral.

The following table provides a reconciliation of assets and liabilities measured at fair value using significant level 3 inputs for the year ended December 31, 2008.

	Energy Marketing Contracts, net	Nuclear Decommissioning Trust	Net Balance
		(In Thousands)	
Balance as of January 1, 2008	$41,141	$ 1,251	$42,392
Total realized and unrealized gains (losses) included in:			
Earnings[a]	(1,454)	—	(1,454)
Regulatory liabilities	12,289[b]	(60)	12,229
Purchases, issuances and settlements	(7,435)	6,843	(592)
Balance as of December 31, 2008	$44,541	$ 8,034	$52,575

[a] *Unrealized and realized gains and losses included in earnings are reported in sales.*

[b] *Regulatory liabilities include changes in the fair value of a fuel supply contract and a capacity sale contract.*

A portion of the gains and losses contributing to changes in net assets in the above table is unrealized. The following table summarizes the unrealized gains and losses we recognized during the year ended December 31, 2008, attributed to level 3 assets and liabilities still held at December 31, 2008.

	Energy Marketing Contracts, net
	(In Thousands)
Total unrealized gains (losses) included in:	
Earnings	$ 2,842
Regulatory liabilities[a]	15,460
Total	$18,302

[a] *Regulatory liabilities include changes in the fair value of a fuel supply contract and a capacity sale contract.*

Derivative Instruments

We are exposed to market risks from changes in commodity prices and interest rates that could affect our consolidated financial statements. We manage our exposure to these market risks through our regular operating and financing activities and, when we deem 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, risk management 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, diesel, oil, coal and electricity. We classify derivative instruments that we use 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 primarily trade electricity and other energy-related products using a variety of financial instruments, including futures 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 attempting to take advantage of market trends and conditions. With the exception of a fuel supply contract and a capacity sale contract, which we record as regulatory liabilities, we include the net mark-to-market change in sales 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 market opportunities. We refer to these transactions as energy marketing activities.

We trade 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 statements.

We have considered a number of risks and costs associated with future contractual commitments 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 exposed to commodity price changes. We use derivative contracts for non trading purposes. We trade various types of fuel primarily to reduce exposure relative to the volatility of market and commodity prices. The wholesale power and fuels markets are 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 types of fossil fuel, including coal, natural gas, diesel and oil, to operate our plants. A significant portion of our coal requirements is 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 we use to generate electricity fluctuate from period to period 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 risk management activities reflect our estimates of fair values considering various factors, including closing exchange and OTC 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.

5. 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 debt and equity investments in a trust used to fund retirement benefits that we classify 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 loss of $9.5 million as of December 31, 2008, an unrealized gain of $2.8 million as of December 31, 2007 and an unrealized gain of $1.7 million as of December 31, 2006.

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 as available-for-sale and have recorded all such investments at their fair market value as of December 31, 2008 and 2007. At December 31, 2008, investments by the nuclear decommissioning trust fund were allocated 64% to equity securities, 26% to debt securities, 7% to real estate, 2% to commodities and 1% to cash and cash equivalents. Investments in debt securities are limited to funds which invest principally in U.S. government and agency securities, municipal bonds, corporate securities or foreign debt. As of December 31, 2008, the fair value of the debt securities in the nuclear decommissioning trust fund was $22.6 million. Of this amount, $21.4 million was held in closed end funds, bond mutual funds and indexed bond funds. As of December 31, 2008, the average maturity of the bonds in these funds ranged from 4.0 years to 7.9 years.

Using the specific identification method to determine cost, we realized a $20.1 million loss in 2008, a $5.7 million gain in 2007 and a $7.5 million gain in 2006 on our available-for-sale securities. We record 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 we recover in rates. Gains or losses on assets in the trust fund are recorded as increases or decreases to regulatory liabilities and 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 the nuclear decommissioning trust fund as of December 31, 2008 and 2007.

Security Type	Cost	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
	(In Thousands)			
2008:				
Equity securities	$ 68,534	$ 2,308	$(16,451)	$ 54,391
Debt securities	25,598	6	(2,968)	22,636
Real estate	6,102	—	(74)	6,028
Commodities	2,511	—	(1,052)	1,459
Cash equivalents	1,041	—	—	1,041
Total	$103,786	$ 2,314	$(20,545)	$ 85,555
2007:				
Equity securities	$ 69,505	$ 19,031	$ (2,971)	$ 85,565
Debt securities	33,705	450	(528)	33,627
Cash equivalents	3,106	—	—	3,106
Total	$106,316	$ 19,481	$ (3,499)	$ 122,298

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 aggregated by investment category and the length of time that individual securities have been in a continuous unrealized loss position, at December 31, 2008.

	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)					
Equity securities	$40,149	$(15,630)	$ 290	$ (821)	$ 40,439	$(16,451)
Debt securities	9,382	(2,791)	310	(177)	9,692	(2,968)
Real estate	6,000	(74)	—	—	6,000	(74)
Commodities	1,459	(1,052)	—	—	1,459	(1,052)
Total	$56,990	$(19,547)	$ 600	$(998)	$57,590	$(20,545)

6. PROPERTY, PLANT AND EQUIPMENT

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

As of December 31,	2008	2007
	(In Thousands)	
Electric plant in service	$7,182,589	$6,452,522
Electric plant acquisition adjustment	802,318	802,318
Accumulated depreciation	(3,249,007)	(3,142,550)
	4,735,900	4,112,290
Construction work in progress	733,816	630,782
Nuclear fuel, net	63,771	60,566
Net utility plant	5,533,487	4,803,638
Non-utility plant in service	34	34
Net property, plant and equipment	$5,533,521	$4,803,672

We recorded depreciation expense on utility property, plant and equipment of $180.8 million in 2008, $170.0 million in 2007 and $159.9 million in 2006.

7. 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 and each owner responsible for its own financing. Information relative to our ownership interest in these facilities as of December 31, 2008, is shown in the table below.

	Our Ownership as of December 31, 2008					
	In-Service Dates	Investment	Accumulated Depreciation	Construction Work in Progress	Net MW	Ownership Percent
		(Dollars in Thousands)				
La Cygne unit 1[a]	June 1973	$ 275,615	$ 130,856	$ 12,968	368	50
Jeffrey unit 1[a]	July 1978	426,667	176,780	24,994	665	92
Jeffrey unit 2[a]	May 1980	321,826	168,139	115,822	661	92
Jeffrey unit 3[a]	May 1983	574,289	233,763	53,718	665	92
Wolf Creek[b]	Sept. 1985	1,459,271	687,135	25,901	545	47
State Line[c]	June 2001	107,216	32,443	144	204	40
Total		$3,164,884	$1,429,116	$233,547	3,108	

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

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 sold and leased back to KGE in 1987, representing 341 megawatts (MW) of capacity. Our share of other transactions associated with the plants is included in the appropriate classification on our consolidated financial statements.

In 2007, we purchased an 8% leasehold interest in Jeffrey Energy Center and assumed the related lease obligation. We recorded a capital lease of $118.5 million related to this transaction. This increased our interest in Jeffrey Energy Center to 92%. Amounts presented above do not include this capital lease or related depreciation.

8. SHORT-TERM DEBT

On January 11, 2008, we filed a request with FERC for authority to issue short-term securities and to pledge KGE mortgage bonds in order to increase the size of Westar Energy's revolving credit facility from $500.0 million to $750.0 million. On February 15, 2008, FERC granted our request and on February 22, 2008, a syndicate of banks in the credit facility increased their commitments to $750.0 million in the aggregate. Effective February 22, 2008, $730.0 million of the commitments of the lenders under the revolving credit facility terminate on March 17, 2012. The remaining $20.0 million of the commitments terminate on March 17, 2011.

Lehman Brothers Commercial Paper, Inc. (Lehman Brothers) is the participating lender with respect to a $20.0 million commitment terminating March 17, 2011. On October 5, 2008, Lehman Brothers filed for bankruptcy protection. Under terms of the credit facility, we have the right to replace Lehman Brothers should another lender or lenders be willing to replace the $20.0 million commitment. To date, we have elected not to seek a replacement lender. As a result, until such time as we seek and locate a replacement lender or lenders, the revolving credit facility is limited to $730.0 million.

The weighted average interest rate on our borrowings under the revolving credit facility was 0.88% and 6.18% as of December 31, 2008, and December 31, 2007, respectively. As of February 18, 2009, $230.2 million had been borrowed and an additional $21.1 million of letters of credit had been issued under the revolving credit facility.

Information regarding our short-term borrowings is as follows.

As of December 31,	2008	2007
	(Dollars in Thousands)	
Weighted average short-term debt outstanding during the year	$270,756	$157,372
Weighted daily average interest rates during the year, excluding fees	3.31%	5.83%

Our interest expense on short-term debt was $9.7 million in 2008 and 2007 and $7.6 million in 2006.

9. LONG-TERM DEBT

Outstanding Debt

The following table summarizes our long-term debt outstanding.

As of December 31,	2008	2007
	(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
6.100% due 2047	150,000	150,000
8.625% due 2018	300,000	—
	1,350,000	1,050,000
Pollution control bond series:		
Variable due 2032, 2.750% as of December 31, 2008; 4.350% as of December 31, 2007	45,000	45,000
Variable due 2032, 2.310% as of December 31, 2008; 4.350% as of December 31, 2007	30,500	30,500
5.000% due 2033	58,215	58,340
	133,715	133,840
Other long-term debt:		
4.360% Equipment financing loan due 2010	2,694	1,825
7.125% unsecured senior notes due 2009	145,078	145,078
	147,772	146,903
KGE		
First mortgage bond series:		
6.530% due 2037	175,000	175,000
6.150% due 2023	50,000	—
6.640% due 2038	100,000	—
	325,000	175,000
Pollution control bond series:		
5.100% due 2023	13,463	13,463
Variable due 2027, 1.950% as of December 31, 2008; 5.250% as of December 31, 2007	21,940	21,940
5.300% due 2031	108,600	108,600
5.300% due 2031	18,900	18,900
Variable due 2031, 5.000% as of December 31, 2007	—	100,000
Variable due 2032, 1.950% as of December 31, 2008; 5.250% as of December 31, 2007	14,500	14,500
Variable due 2032, 1.950% as of December 31, 2008; 4.500% as of December 31, 2007	10,000	10,000
4.850% due 2031	50,000	50,000
Variable due 2031, 1.647% as of December 31, 2008; 5.250% as of December 31, 2007	50,000	50,000
5.600% due 2031	50,000	—
6.000% due 2031	50,000	—
	387,403	387,403
Total long-term debt	2,343,890	1,893,146
Unamortized debt discount[a]	(4,986)	(2,807)
Long-term debt due within one year	(146,366)	(558)
Long-term debt, net	$2,192,538	$1,889,781

[a] *We amortize debt discount to interest expense 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, 2008, based on an assumed interest rate of 7.50%, approximately $138.0 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, 2008, based on an assumed interest rate of 7.50%, approximately $415.0 million principal amount of additional KGE first mortgage bonds could be issued under the most restrictive provisions in KGE's mortgage.

As of December 31, 2008, we had $171.9 million of variable rate, tax-exempt bonds. Interest rates payable under these bonds have historically been set by auctions, which occur every 35 days. During 2008, auctions for these bonds failed, resulting in alternative index-based interest rates for these bonds of between 1% and 14%. On July 31, 2008, the KCC approved our request to remarket or refund all or part of these auction rate bonds, at our discretion. On August 26, 2008, we completed the refunding of $50.0 million of auction rate bonds at a fixed interest rate of 5.60% and a maturity date of June 1, 2031. On October 10, 2008, we completed the refunding of an additional $50.0 million of auction rate bonds at a fixed interest rate of 6.00% and a maturity date of June 1, 2031. We continue to monitor the credit markets and evaluate our options with respect to the remaining auction rate bonds.

On November 25, 2008, Westar Energy issued $300.0 million principal amount of first mortgage bonds at a discount to yield 8.750%, but bearing interest at 8.625%, and maturing on December 1, 2018. We received net proceeds of $295.6 million.

On May 15, 2008, KGE issued $150.0 million principal amount of first mortgage bonds in a private placement transaction with $50.0 million of the principal amount bearing interest at 6.15% and maturing on May 15, 2023, and $100.0 million bearing interest at 6.64% and maturing on May 15, 2038.

In December 2007, we entered into a $1.8 million equipment financing loan agreement with a term of 36 months to finance the cost of certain computer equipment purchased in 2007. In January 2008, we increased the size of this loan by $2.1 million to $3.9 million for equipment purchases made in 2008. As of December 31, 2008, the balance of this loan was $2.7 million.

On October 15, 2007, KGE issued $175.0 million principal amount of 6.53% first mortgage bonds maturing in 2037 in a private placement to an institutional investor.

On May 16, 2007, Westar Energy sold $150.0 million aggregate principal amount of 6.10% Westar Energy first mortgage bonds maturing in 2047.

Proceeds from the issuance of first mortgage bonds were used to repay borrowings under Westar Energy's revolving credit facility, with those borrowed amounts principally related to investments in capital equipment, as well as for working capital and general corporate purposes.

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, 2008.

Maturities

Maturities of long-term debt as of December 31, 2008, are as follows.

Year	Principal Amount
	(In Thousands)
2009	$ 146,366
2010	1,345
2011	61
2012	—
Thereafter	2,196,118
Total long-term debt maturities	$2,343,890

Our interest expense on long-term debt was $95.7 million in 2008, $94.2 million in 2007 and $91.0 million in 2006.

10. TAXES

Income tax expense is composed of the following components.

Year Ended December 31,	2008	2007	2006
		(In Thousands)	
Income Tax Expense (Benefit) from Continuing Operations:			
Current income taxes:			
Federal	$(16,484)	$40,648	$ 46,211
State	(14,841)	9,107	14,303
Deferred income taxes:			
Federal	35,818	9,962	(1,150)
State	2,147	6,240	578
Investment tax credit amortization	(2,704)	(2,118)	(3,630)
Income tax expense from continuing operations	$ 3,936	$63,839	$ 56,312

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

December 31,	2008	2007
	(In Thousands)	
Current deferred tax assets	$ 16,416	$ —
Current deferred tax liabilities	—	2,310
Non-current deferred tax liabilities	1,004,920	897,293
Net deferred tax liabilities	$988,504	$899,603

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,	2008	2007
	(In Thousands)	
Deferred tax assets:		
Capital loss carryforward[a]	$ 215,946	$ 216,626
Deferred employee benefit costs	176,061	82,752
Deferred gain on sale-leaseback	50,218	52,616
Accrued liabilities	33,038	29,248
Disallowed costs	14,648	15,301
Alternative minimum tax carryforward[b]	7,811	357
Long-term energy contracts	7,088	8,262
Business tax credit carryforward[c]	6,528	1,488
Other	61,206	91,951
Total gross deferred tax assets	572,544	498,601
Less: Valuation allowance[a]	219,537	220,146
Deferred tax assets	$ 353,007	$ 278,455
Deferred tax liabilities:		
Accelerated depreciation	$ 709,097	$ 644,707
Acquisition premium	211,972	219,985
Amounts due from customers for future income taxes, net	179,283	151,279
Deferred employee benefit costs	173,457	79,693
Other	67,702	82,394
Total deferred tax liabilities	$1,341,511	$1,178,058
Net deferred tax liabilities	$ 988,504	$ 899,603

[a] *As of December 31, 2008, we have a net capital loss of $545.1 million which is available to offset future capital gains. Of this amount $544.6 million will expire in 2009 and $0.5 million will expire in 2013. As we do not expect to realize any significant capital gains in the future, a valuation allowance of $215.7 million has been established. In addition, a valuation allowance of $3.8 million has been established for certain deferred tax assets related to the write-down of other investments. The total valuation allowance related to the deferred tax assets was $219.5 million as of December 31, 2008, and $220.1 million as of December 31, 2007. The net reduction in valuation allowance of $0.6 million was due primarily to a reduction in the state corporate income tax rate in 2008. See the discussion below regarding the settlement with the Internal Revenue Service (IRS) Office of Appeals for years 2003 and 2004.*

[b] *As of December 31, 2008, we had available alternative minimum tax credit carryforwards of $7.8 million. These tax credits have an unlimited carryforward period.*

[c] *As of December 31, 2008, we had available federal general business tax credits of $3.2 million and state investment tax credits of $3.3 million. The federal general business tax credits were 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 recognized $14.6 million in 2008 for state tax incentives related to investment and jobs creation within the state of Kansas. The state investment tax credits expire beginning 2012. We believe these tax credits will be fully utilized before expiration.*

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 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,	2008	2007	2006
Statutory federal income tax rate from continuing operations	35.0 %	35.0 %	35.0 %
Effect of:			
(Resolution) establishment of uncertain tax positions	(15.4)	0.6	0.7
Corporate-owned life insurance policies	(9.1)	(5.8)	(8.3)
State income taxes	(4.5)	4.4	4.4
AFUDC equity	(3.5)	(0.6)	—
Accelerated depreciation flow through and amortization	2.3	2.7	1.4
Amortization of investment tax credits	(1.5)	(0.9)	(1.6)
Net operating loss utilization	—	(5.1)	(0.9)
Capital loss utilization	—	(1.2)	(4.0)
Other	(1.1)	(1.6)	(1.3)
Effective income tax rate from continuing operations	2.2 %	27.5 %	25.4 %

We file income tax returns in the U.S. federal jurisdiction, and various states and foreign jurisdictions. The income tax returns we filed will likely be audited by the IRS or other taxing authorities. With few exceptions, the statute of limitations with respect to U.S. federal, state and local, or non-U.S. income tax examinations by tax authorities are closed for years before 2003. Our 2007, 2006, and 2005 income tax returns are subject to audit by federal and state taxing authorities.

The IRS has examined our federal income tax returns for the years 1995 through 2002. In December 2007, we tentatively reached a settlement with the IRS Office of Appeals on issues principally related to the method used to capitalize overheads to electric plant. This settlement, which was approved by the Joint Committee on Taxation and accepted by the IRS in February 2008, resulted in a 2008 net earnings benefit of approximately $39.4 million, including interest, due to the recognition of previously unrecognized tax benefits. The statute of limitations for these years has expired.

In April 2008, the IRS completed its examination of the federal income tax returns filed for years 2003 and 2004. In its examination report, the IRS did not approve our refund claim to change the original federal income tax characterization of the loss we incurred in 2004 on the sale of Protection One, Inc. (Protection One) from a capital loss to an ordinary loss. The characterization of the loss as capital or ordinary affects our ability to carryback and carryforward the loss to tax years in which the loss can be utilized. In June 2008, we filed a protest with the IRS Office of Appeals to pursue the re-characterization of the loss. In November 2008, we reached a tentative settlement with the IRS Office of Appeals (IRS Appeals Settlement) on the amount of the net capital loss and net operating loss carryforwards as of the end of December 31, 2004. This tentative settlement was subject to review by the Joint Committee on Taxation of the U.S. Congress. On December 22, 2008, we were notified that the Joint Committee on Taxation questioned the appropriateness of the settlement. We responded to the Joint Committee on Taxation's questions and submitted our response on December 29, 2008. On January 14, 2009, the IRS notified us that the Joint Committee on Taxation had approved the IRS Appeals Settlement. Given the degree of uncertainty regarding this issue we were unable to conclude that realization of the benefit was more likely than not at December 31, 2008. Under the terms of our tax sharing agreement, we reimburse subsidiaries for current tax benefits used in our consolidated tax return. Under an agreement relating to the sale transaction, we will pay Protection One an amount equal to 50% of the net tax benefit (less certain adjustments) that we receive from the net operating loss carryforward arising from the sale. The recognition of this previously unrecognized tax benefit in accordance with the provisions of FIN 48 will result in a net earnings benefit of approximately $32.5 million. We have extended the statute of limitations for these years until September 30, 2009.

At December 31, 2007, the amount of unrecognized tax benefits and the FIN 48 liability were $209.6 million and $70.8 million, respectively. During 2008, the FIN 48 liability decreased from $70.8 million to $39.0 million and the amount of unrecognized tax benefits decreased from $209.6 million to $92.1 million. The net decrease in FIN 48 liability is primarily attributable to the recognition of $28.7 million of unrecognized tax benefits due to the completion of the IRS examination of years 1995 through 2002. We expect a reduction of unrecognized tax benefits in the amount of $60.2 million in the first quarter of 2009 due to the IRS Appeals Settlement for years 2003 and 2004. We do not expect any other significant increases or decreases to the liability for unrecognized tax benefits within the next 12 months. A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

	2008	2007
	(In Thousands)	
FIN 48 liability at January 1	$ 70,833	$ 50,211
Additions based on tax positions related to the current year	4,576	21,660
Additions for tax positions of prior years	—	5,197
Reductions for tax positions of prior years	(3,639)	—
Settlements	(32,790)	(6,235)
FIN 48 liability at December 31, 2008	38,980	70,833
Unrecognized tax benefits related to amended returns filed in 2007	53,092	138,778
Unrecognized tax benefits at December 31	$ 92,072	$ 209,611

The amounts of unrecognized tax benefits that, if recognized, would favorably impact our effective tax rate, are $54.8 million and $172.2 million (net of tax) as of December 31, 2008 and December 31, 2007, respectively. Included in the FIN 48 liability are $1.7 million and $33.4 million (net of tax) of tax positions, which if recognized, would favorably impact our effective income tax rate as of December 31, 2008 and December 31, 2007, respectively.

Interest related to income tax uncertainties is classified as interest expense and accrued interest liability. As of December 31, 2008, and December 31, 2007, we had $3.8 million and $13.5 million, respectively, accrued for interest on our liability related to unrecognized tax benefits. There were no penalties accrued at either December 31, 2008, or December 31, 2007.

As of December 31, 2008 and 2007, we maintained reserves of $3.5 million and $5.2 million, respectively, for probable assessments of taxes other than income taxes.

11. 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 Employee Retirement Income Security Act (ERISA) as amended by the Pension Protection Act (PPA) and the Internal Revenue Code plus additional amounts we consider appropriate. Non-union employees hired after December 31, 2001, are covered by the same defined benefit plan, however, their benefits are 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. With the exception of one current officer, we have discontinued accruing any future benefits under this non-qualified plan.

In addition to providing pension benefits, we provide certain post-retirement health care and life insurance benefits for substantially all retired employees. We accrue and recover in rates the cost of post-retirement benefits during an employee's years of service. We fund the portion of net periodic post-retirement benefit costs 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 12, "Wolf Creek Employee Benefit Plans" for information about Wolf Creek's benefit plans.

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

	Pension Benefits		Post-retirement Benefits	
As of December 31,	2008	2007	2008	2007
	(In Thousands)			
Change in Benefit Obligation:				
Benefit obligation, beginning of year	$ 578,191	$ 551,728	$ 134,135	$ 124,546
Service cost	10,102	9,641	1,446	1,548
Interest cost	35,792	32,418	7,637	7,574
Plan participants' contributions	—	—	4,162	4,164
Benefits paid	(28,459)	(28,450)	(9,639)	(11,481)
Actuarial losses (gains)	32,151	12,718	(6,541)	(5,994)
Amendments	1,461	136	2,681	13,778
Benefit obligation, end of year	$ 629,238	$ 578,191	$ 133,881	$ 134,135
Change in Plan Assets:				
Fair value of plan assets, beginning of year	$ 468,188	$ 451,824	$ 61,423	$ 52,778
Actual return on plan assets	(145,962)	31,208	(14,762)	3,215
Employer contribution	15,000	11,800	11,348	12,400
Plan participants' contributions	—	—	3,996	4,030
Part D Reimbursements	—	—	1,465	814
Benefits paid	(26,695)	(26,644)	(10,666)	(11,814)
Fair value of plan assets, end of year	$ 310,531	$ 468,188	$ 52,804	$ 61,423
Funded status, end of year	$ (318,707)	$(110,003)	$ (81,077)	$ (72,712)
Amounts Recognized in the Balance Sheets Consist of:				
Current liability	$ (1,933)	$ (1,838)	$ (125)	$ (130)
Noncurrent liability	(316,774)	(108,165)	(80,952)	(72,582)
Net amount recognized	$ (318,707)	$(110,003)	$ (81,077)	$ (72,712)
Amounts Recognized in Regulatory Assets Consist of:				
Net actuarial loss	$ 324,290	$ 114,325	$ 31,648	$ 19,636
Prior service cost	10,492	11,517	14,127	12,858
Transition obligation	—	—	16,048	19,979
Net amount recognized	$ 334,782	$ 125,842	$ 61,823	$ 52,473

As of December 31,	Pension Benefits 2008	Pension Benefits 2007	Post-retirement Benefits 2008	Post-retirement Benefits 2007
	(Dollars in Thousands)			
Pension Plans With a Projected Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$629,238	$578,191	$ —	$ —
Accumulated benefit obligation	531,145	497,169	—	—
Fair value of plan assets	310,531	468,188	—	—
Pension Plans With an Accumulated Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$629,238	$578,191	$ —	$ —
Accumulated benefit obligation	531,145	497,169	—	—
Fair value of plan assets	310,531	468,188	—	—
Post-retirement Plans With an Accumulated Post-retirement Benefit Obligation In Excess of Plan Assets:				
Accumulated post-retirement benefit obligation	$ —	$ —	$ 133,881	$ 134,135
Fair value of plan assets	—	—	52,804	61,423
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Benefit Obligation:				
Discount rate	6.10%	6.25%	6.05%	6.10%
Compensation rate increase	4.00%	4.00%	—	—

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 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. We amortize the net actuarial loss 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 2008	Pension Benefits 2007	Pension Benefits 2006
	(Dollars in Thousands)		
Components of Net Periodic Cost (Benefit):			
Service cost	$ 10,102	$ 9,641	$ 9,178
Interest cost	35,792	32,418	30,522
Expected return on plan assets	(40,332)	(38,506)	(35,939)
Amortization of unrecognized:			
Transition obligation, net	—	—	—
Prior service costs/(benefit)	2,550	2,545	2,892
Actuarial loss, net	8,415	7,864	8,759
Net periodic cost	$ 16,527	$13,962	$ 15,412
Other Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets:			
Current year actuarial loss/(gain)	$218,444	$20,017	$ —
Amortization of actuarial loss	(8,415)	(7,864)	—
Current year prior service cost	1,461	136	—
Amortization of prior service cost	(2,550)	(2,545)	—
Amortization of transition obligation	—	—	—
Total recognized in regulatory assets	$208,940	$ 9,744	$ —
Total recognized in net periodic cost and regulatory assets	$225,467	$23,706	$ 15,412
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost (Benefit):			
Discount rate	6.25%	5.90%	5.65%
Expected long-term return on plan assets	8.50%	8.50%	8.50%
Compensation rate increase	4.00%	4.00%	3.50%

Year Ended December 31,	Post-retirement Benefits 2008	Post-retirement Benefits 2007	Post-retirement Benefits 2006
	(Dollars in Thousands)		
Components of Net Periodic Cost (Benefit):			
Service cost	$ 1,446	$ 1,548	$ 1,492
Interest cost	7,637	7,574	6,875
Expected return on plan assets	(4,694)	(3,827)	(2,971)
Amortization of unrecognized:			
Transition obligation, net	3,930	3,930	3,931
Prior service costs/(benefit)	1,412	937	(415)
Actuarial loss, net	904	1,503	2,001
Net periodic cost	$10,635	$11,665	$ 10,913
Other Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets:			
Current year actuarial loss/(gain)	$12,915	$(5,431)	$ —
Amortization of actuarial loss	(904)	(1,503)	—
Current year prior service cost	2,681	13,778	—
Amortization of prior service cost	(1,412)	(937)	—
Amortization of transition obligation	(3,930)	(3,930)	—
Total recognized in regulatory assets	$ 9,350	$ 1,977	$ —
Total recognized in net periodic cost and regulatory assets	$19,985	$13,642	$ 10,913
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost (Benefit):			
Discount rate	6.10%	5.80%	5.65%
Expected long-term return on plan assets	7.75%	7.75%	7.75%
Compensation rate increase	—	—	—

The estimated amounts that will be amortized from regulatory assets into net periodic benefit cost in 2009 are as follows:

	Pension Benefits	Other Post-retirement Benefits
	(In Thousands)	
Actuarial loss	$14,261	$ 1,276
Prior service cost	2,662	1,592
Transition obligation	—	3,930
Total	$16,923	$ 6,798

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. We selected assumed projected rates of return for each asset class 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, we developed an overall expected rate of return for the portfolio, 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.

The Medicare Prescription Drug Improvement and Modernization Act of 2003 (Medicare Act) introduced a prescription drug benefit under Medicare as well as a federal subsidy that 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, thus, eligible for the federal subsidy. 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 $4.0 million in 2008 and $4.6 million in both 2007 and 2006. The subsidy also decreased the net periodic post-retirement benefit cost by approximately $0.5 million for 2008 and $0.6 million for both 2007 and 2006.

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

As of December 31,	2008	2007
Health care cost trend rate assumed for next year	7.50%	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	2014	2014

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	$ 9	$ (13)
Effect on post-retirement benefit obligation	85	(203)

The asset allocation for the pension plans and the post-retirement benefit plans at the end of 2008 and 2007, and the target allocations for 2009, by asset category, are as shown in the following table.

	Target Allocations	Plan Assets	
Asset Category	2009	2008	2007
Pension Plans:			
Equity securities	62%	60%	67%
Debt securities	30%	29%	29%
Real estate	5%	7%	—
Commodities	3%	2%	—
Cash	0% - 5%	2%	4%
Total		100%	100%
Post-retirement Benefit Plans:			
Equity securities	65%	60%	60%
Debt securities	30%	32%	29%
Cash	5%	8%	11%
Total		100%	100%

We manage pension and retiree welfare plan assets in accordance with the "prudent investor" guidelines contained in the 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. We diversify investments 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. We measure and monitor investment risk 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:				
2009	$ 51.9[a]	$ 1.9	$ 12.3	$ 0.1
Expected benefit payments:				
2009	$ (26.8)	$ (1.9)	$ (7.5)	$ (0.1)
2010	(27.2)	(1.9)	(7.8)	(0.1)
2011	(27.8)	(1.9)	(8.1)	(0.1)
2012	(28.9)	(1.9)	(8.4)	(0.1)
2013	(30.5)	(1.9)	(8.7)	(0.1)
2014 – 2018	(185.4)	(8.9)	(49.9)	(0.7)

[a] *Includes required contributions of $12.9 million and voluntary contributions of $39.0 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 $6.1 million in 2008, $5.6 million in 2007 and $4.8 million in 2006.

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, 2008, awards of 3,836,430 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. 123R, "Share-Based Payment," 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. 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,	2008	2007	2006
		(In Thousands)	
Compensation expense	$4,619	$5,735	$ 3,395
Income tax benefits related to stock-based compensation arrangements	1,830	2,281	1,350

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, 2008, our RSU activity was as follows:

As of December 31,	2008		2007		2006	
	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	984.2	$23.11	933.4	$20.82	1,094.5	$18.54
Granted	38.7	25.46	413.8	26.76	160.3	23.91
Vested	(261.3)	28.11	(308.5)	20.53	(306.6)	14.96
Forfeited	(34.2)	35.49	(54.5)	26.79	(14.8)	21.56
Nonvested balance, end of year	727.4	20.86	984.2	23.11	933.4	20.82

Total unrecognized compensation cost related to RSU awards was $5.8 million as of December 31, 2008. We expect to recognize these costs over a remaining weighted-average period of 1.8 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, 2008, 2007 and 2006, was $6.2 million, $8.3 million and $7.2 million, respectively. There were no modifications of awards during the years ended December 31, 2008, 2007 or 2006.

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, 2008, and December 31, 2007, we had temporary equity of $3.4 million and $5.2 million, respectively, 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 1998 and 2001 are completely vested and expire 10 years from the date of grant. All 23,700 outstanding options are exercisable. There were no options exercised and 53,590 options were forfeited during the year ended December 31, 2008. 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 5,283 shares of common stock for dividends in 2008, 4,214 shares in 2007 and 4,407 shares in 2006. Participants received common stock distributions of 530 shares in 2008, 505 shares in 2007 and 1,936 shares in 2006.

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 is classified as cash flows from financing activities in the consolidated statements of cash flows.

12. 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,	2008	2007	2008	2007
	(In Thousands)			
Change in Benefit Obligation:				
Benefit obligation, beginning of year	$ 89,846	$ 79,213	$ 8,596	$ 7,391
Effect of eliminating early measurement date	574	—	—	—
Service cost	3,421	3,436	203	234
Interest cost	5,680	4,696	517	435
Plan participants' contributions	—	—	356	294
Benefits paid	(2,135)	(1,809)	(1,182)	(509)
Actuarial losses/(gains)	2,150	2,071	362	(114)
Amendments	—	34	—	—
Curtailments, settlements and special termination benefits	—	2,205	—	865
Benefit obligation, end of year	$ 99,536	$ 89,846	$ 8,852	$ 8,596

	Pension Benefits		Post-retirement Benefits	
As of December 31,	2008	2007	2008	2007
	(In Thousands)			
Change in Plan Assets:				
Fair value of plan assets, beginning of year	$ 54,992	$ 47,869	$ —	$ —
Effect of eliminating early measurement date	226	—	—	—
Actual return on plan assets	(14,656)	3,314	—	—
Employer contribution	6,608	5,618	—	—
Benefits paid	(1,969)	(1,809)	—	—
Fair value of plan assets, end of year	$ 45,201	$ 54,992	$ —	$ —
Funded status	$ (54,335)	$ (34,854)	$ (8,852)	$ (8,596)
Post-measurement date adjustments	—	1,072	—	—
Accrued post-retirement benefit costs	$ (54,335)	$ (33,782)	$ (8,852)	$ (8,596)
Amounts Recognized in the Balance Sheets Consist of:				
Current liability	$ (251)	$ (168)	$ (612)	$ (632)
Noncurrent liability	(54,084)	(33,614)	(8,240)	(7,964)
Net amount recognized	$ (54,335)	$ (33,782)	$ (8,852)	$ (8,596)
Amounts Recognized in Regulatory Assets Consist of:				
Net actuarial loss	$ 40,802	$ 21,120	$ 3,258	$ 3,127
Prior service cost	119	178	—	—
Transition obligation	166	227	230	288
Net amount recognized	$ 41,087	$ 21,525	$ 3,488	$ 3,415

	Pension Benefits		Post-retirement Benefits	
As of December 31,	2008	2007	2008	2007
	(Dollars in Thousands)			
Pension Plans With a Projected Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$ 99,536	$ 89,846	$ —	$ —
Accumulated benefit obligation	77,197	68,302	—	—
Fair value of plan assets	45,201	54,992	—	—
Pension Plans With an Accumulated Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$ 99,536	$ 89,846	$ —	$ —
Accumulated benefit obligation	77,197	68,302	—	—
Fair value of plan assets	45,201	54,992	—	—
Post-retirement Plans With an Accumulated Post-retirement Benefit Obligation In Excess of Plan Assets:				
Accumulated post-retirement benefit obligation	$ —	$ —	$ 8,852	$ 8,596
Fair value of plan assets	—	—	—	—
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Benefit Obligation:				
Discount rate	6.15%	6.15%	6.05%	6.05%
Compensation rate increase	4.00%	4.00%	—	—

During 2008, Wolf Creek changed the measurement date for its pension and post-retirement benefit plans from December 1 to December 31. As a result, we decreased retained earnings by $0.5 million and decreased regulatory assets by $0.1 million.

Wolf Creek uses an interest rate yield curve to make judgments pursuant to 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.

	Pension Benefits		
Year Ended December 31,	2008	2007	2006
	(Dollars in Thousands)		
Components of Net Periodic Cost:			
Service cost	$ 3,421	$ 3,436	$ 3,245
Interest cost	5,680	4,696	4,293
Expected return on plan assets	(4,709)	(4,101)	(3,428)
Amortization of unrecognized:			
Transition obligation, net	57	57	57
Prior service costs	57	57	31
Actuarial loss, net	1,696	1,855	1,813
Curtailments, settlements and special termination benefits	—	1,486	—
Net periodic cost	$ 6,202	$ 7,486	$ 6,011
Other Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets:			
Current year actuarial loss	$21,517	$ 3,578	$ —
Amortization of actuarial loss	(1,696)	(1,855)	—
Current year prior service cost	—	34	—
Amortization of prior service cost	(57)	(57)	—
Amortization of transition obligation	(57)	(57)	—
Total recognized in regulatory assets	$19,707	$ 1,643	$ —
Total recognized in net periodic cost and regulatory assets	$25,909	$ 9,129	$ 6,011
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost:			
Discount rate	6.15%	5.70%	5.75%
Expected long-term return on plan assets	8.25%	8.25%	8.25%
Compensation rate increase	4.00%	3.25%	3.25%

	Post-retirement Benefits		
Year Ended December 31,	2008	2007	2006
	(Dollars in Thousands)		
Components of Net Periodic Cost:			
Service cost	$ 203	$ 234	$ 248
Interest cost	517	435	412
Expected return on plan assets	—	—	—
Amortization of unrecognized:			
Transition obligation, net	58	58	58
Prior service costs	—	—	—
Actuarial loss, net	231	191	196
Curtailments, settlements and special termination benefits	—	259	—
Net periodic cost	$ 1,009	$ 1,177	$ 914
Other Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets:			
Current year actuarial loss	$ 362	$ 786	$ —
Amortization of actuarial loss	(231)	(191)	—
Current year prior service cost	—	—	—
Amortization of prior service cost	—	—	—
Amortization of transition obligation	(58)	(58)	—
Total recognized in regulatory assets	$ 73	$ 537	$ —
Total recognized in net periodic cost and regulatory assets	$ 1,082	$ 1,714	$ 914
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost:			
Discount rate	6.05%	5.80%	5.75%
Expected long-term return on plan assets	—	—	—
Compensation rate increase	—	—	—

In January 2007, Wolf Creek Nuclear Operating Corporation (WCNOC) offered a selective retirement incentive to employees. The incentive increased the pension benefit for eligible employees who elected retirement. This resulted in $1.5 million in additional pension benefits and $0.3 million in additional post-retirement benefits for the year ended December 31, 2007.

The estimated amounts that will be amortized from regulatory assets into net periodic cost in 2009 are as follows:

	Pension Benefits	Other Post-retirement Benefits
	(In Thousands)	
Actuarial loss	$ 2,387	$ 237
Prior service cost	43	—
Transition obligation	57	58
Total	$ 2,487	$ 295

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,	2008	2007
Health care cost trend rate assumed for next year	7.5%	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	2014	2014

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)	$ 5
Effect on the present value of the projected benefit obligation	(36)	28

The asset allocation for the pension plans at the end of 2008 and 2007, and the target allocation for 2009, by asset category are as shown in the following table.

	Target Allocations	Plan Assets	
Asset Category	2009	2008	2007
Pension Plans:			
Equity securities	65%	59%	67%
Debt securities	25%	39%	28%
Real estate	5%	—	—
Commodities	5%	—	—
Cash	—	2%	5%
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.

	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:				
2009	$ 11.8[a]	$ 0.2	$ —	$ 0.6
Expected benefit payments:				
2009	$ (2.2)	$(0.2)	$ —	$(0.6)
2010	(2.4)	(0.2)	—	(0.6)
2011	(2.6)	(0.2)	—	(0.6)
2012	(2.9)	(0.2)	—	(0.6)
2013	(3.2)	(0.2)	—	(0.7)
2014 – 2018	(23.8)	(1.2)	—	(3.5)

[a] *Includes required funding of $4.4 million and voluntary funding of $7.4 million.*

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 $1.0 million in 2008 and $0.9 million in 2007 and 2006.

13. COMMITMENTS AND CONTINGENCIES

Purchase Orders and Contracts

As part of our ongoing operations and construction program, we have purchase orders and contracts, excluding fuel, which is discussed below under "— Purchased Power and Fuel Commitments," that have an unexpended balance of approximately $674.0 million as of December 31, 2008, of which $270.5 million has been committed. The $270.5 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, 2008, was as follows.

	Committed Amount
	(In Thousands)
2009	$ 174,736
2010	73,310
2011	13,226
Thereafter	9,203
Total amount committed	$ 270,475

Clean Air Act

We must comply with the Clean Air Act, state laws and implement-ing regulations that impose, among other things, limitations on pollutants generated during our operations, 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 certain emissions. We have installed continuous monitoring and reporting equipment in order to meet these requirements.

Environmental Projects

We have identified the potential for us to make up to $1.3 billion of capital expenditures at our power plants for environmental air emissions projects during the next six years. This estimate could materially increase or decrease depending on the timing and the nature of required investments, the specific outcomes resulting from interpretation of existing regulations, new regulations, legislation and the resolution of the Environmental Protection Agency (EPA) New Source Review Investigation (NSR Investigation) and the related Department of Justice (DOJ) lawsuit described below. In addition to the capital investment, in the event we install new equipment as a result of the NSR Investigation and the related DOJ lawsuit, such equipment may cause us to incur significant increases in annual operating and maintenance expense and may reduce net production from our power plants. The degree to which we will need to reduce emissions and the timing of when such emissions controls may be required is uncertain. In addition, our ability to access capital markets and the availability of materials, equipment and contractors may affect the timing and ultimate amount of these capital investments.

The ECRR allows for the more timely inclusion in retail rates of capital expenditures tied directly to environmental improvements, including those required by the Clean Air Act. However, increased operating and maintenance costs, other than expenses related to production-related consumables (e.g., limestone), can be recovered only through a change in base rates following a rate review.

On February 28, 2008, we reached an agreement with the Kansas Department of Health and Environment (KDHE) to implement a plan to improve efficiency and to install new equipment to reduce regulated emissions from Jeffrey Energy Center. The projects are designed to meet requirements of the Clean Air Visibility Rule and reduce emissions over our entire generating fleet by eliminating more than 70% of SO_2 and reducing nitrous oxides between 50% and 65%.

On March 15, 2005, the EPA issued the Clean Air Mercury Rule. Beginning in 2010, the rule caps permanently and reduces the amount of mercury that may be emitted from coal-fired power plants. However, on February 8, 2008, the U.S. District Court of Appeals for the District of Columbia vacated the Clean Air Mercury Rule. While the ultimate impact of this ruling on our operations is currently unknown, we believe that mercury emissions controls may be required in the future and that the costs to comply with these requirements may be material.

New Source Review Investigation

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 the New Source Review permitting program 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 reasonably have been expected to result in a significant net increase in emissions. The New Source Review program requires companies to obtain permits and, if necessary, install control equipment to address 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 certain requirements of the New Source Review program. On February 4, 2009, the DOJ filed a lawsuit against us in U.S. District Court in the District of Kansas asserting substantially the same claims. A decision in favor of the DOJ and the EPA, or a settlement prior to such a decision, if reached, 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. Our ultimate costs to resolve the NSR Investigation and the related DOJ lawsuit could be material. We believe that costs related to updating or installing emissions controls would qualify for recovery in the prices we are allowed to charge our customers. If, however, a penalty is assessed against us, 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.

FERC Investigation

We are responding to a preliminary investigation by FERC of our use of transmission service within the Southwest Power Pool (SPP) in 2007 and 2006. While we believe that our use of transmission service was in compliance with FERC orders and SPP tariffs, we are unable to predict the outcome of this investigation or its impact on our consolidated financial statements.

Manufactured Gas Sites

We have been identified as being partially responsible for remediating 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, Inc. (ONEOK), the current owner of some of the 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 the former manufactured gas sites identified in Missouri is limited to $7.5 million by the terms of an environmental indemnity agreement with the purchaser of our former Missouri assets.

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 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 next review is scheduled to occur in 2009.

The KCC reviews nuclear decommissioning plans in two phases. Phase one is the approval of the revised nuclear decommissioning study including the estimated costs to decommission the plant. 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. The actual nuclear decommissioning costs may vary from the estimates because of changes in regulations, technologies 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 is 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 operating license expires in 2045. We believe that the KCC approved funding level will also be sufficient to meet the NRC minimum financial assurance requirement. Our consolidated statements of income would be materially adversely affected if we were 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 for nuclear decommissioning approximately $2.9 million in 2008 and 2007 and $3.9 million in 2006. We record our investment in the nuclear decommissioning fund at fair value. The fair value approximated $85.6 million as of December 31, 2008, and $122.3 million as of December 31, 2007. During 2008, the value of these financial assets declined significantly. As a result, we will likely have to contribute additional amounts to the nuclear decommissioning fund. We expect to collect those amounts from our customers.

Storage of Spent Nuclear Fuel

Under the Nuclear Waste Policy Act of 1982, the Department of Energy (DOE) is responsible for the permanent disposal of spent nuclear fuel. As required by federal law, the Wolf Creek co-owners entered into a standard contract with the DOE in 1984 in which the DOE promised to begin accepting from commercial nuclear power plants their used nuclear fuel for disposal beginning in early 1998. In return, Wolf Creek pays into a federal Nuclear Waste Fund administered by the DOE a quarterly fee for the future disposal of spent nuclear fuel. Our share of the fee was $3.5 million in 2008, $4.4 million in 2007 and $4.1 million in 2006 and is calculated as one-tenth of a cent for each kilowatt-hour of net nuclear generation delivered to customers. We include these disposal costs in fuel and purchased power 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. On June 3, 2008, the DOE submitted a license application to the NRC seeking authorization to construct the nuclear waste repository at the Yucca Mountain site. 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. The nuclear liability and property insurance programs subscribed to by members of the nuclear power generating industry no longer 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 $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. 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 $12.5 billion. This limit of liability consists of the maximum available commercial insurance of $300.0 million, and the remaining $12.2 billion is provided through mandatory participation in an industry-wide retrospective assessment program. Under this retrospective assessment program, the owners of WCNOC can be assessed a total of $117.5 million (our share is $55.2 million), payable at no more than $17.5 million (our share is $8.2 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 August 2013. 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 $23.3 million (our share is $11.0 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 statements.

Purchased Power and 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, 2008, our share of Wolf Creek's nuclear fuel commitments were approximately $56.9 million for uranium concentrates expiring in 2016, $8.3 million for conversion expiring in 2016, $147.2 million for enrichment expiring in 2024 and $50.8 million for fabrication expiring in 2024.

As of December 31, 2008, our coal and coal transportation contract commitments in 2008 dollars under the remaining terms of the contracts were approximately $1.5 billion. The two largest contracts expire in 2013 and 2020, with the remaining contracts expiring at various times prior to 2013.

As of December 31, 2008, our natural gas transportation commitments in 2008 dollars under the remaining terms of the contracts were approximately $196.5 million. The natural gas transportation contracts provide firm service to several of our natural gas burning facilities and expire at various times through 2028.

During 2007, we entered into power purchase agreements with the owners of two separate wind generation facilities located in Kansas with a combined capacity of 146 MW. The agreements have a term of 20 years and provide for our receipt and purchase of the energy produced at a fixed price per unit of output. We estimate that our annual cost for energy purchased from these wind generation facilities will be approximately $19.5 million. One of the facilities was placed in service in December 2008 and we expect the other one to be placed in service in early 2009.

14. ASSET RETIREMENT OBLIGATIONS

Legal Liability

In accordance with SFAS No. 143, "Accounting for Asset Retirement Obligations" and FIN 47, "Accounting for Conditional Asset Retirement Obligations", 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. The recording of asset retirement obligations 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.

We initially recorded asset retirement obligations at fair value for the estimated cost to decommission Wolf Creek (our 47% share), dispose of asbestos insulating material at our power plants, remediate ash disposal ponds and dispose 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,	2008	2007
	(In Thousands)	
Beginning asset retirement obligations	$ 88,711	$ 84,192
Liabilities incurred	1,143	85
Liabilities settled	(195)	(987)
Accretion expense	5,424	5,421
Ending asset retirement obligations	$ 95,083	$ 88,711

We have adopted the provisions of FIN 47, which clarifies the meaning of 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 the disposal of asbestos insulating material at our power plants, the remediation of ash disposal ponds and the disposal of PCB-contaminated oil.

The amount of the retirement obligation related to asbestos disposal was recorded as of 1990, the date when the EPA 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-contaminated oil is contained within company electrical equipment, primarily transformers. The PCB retirement obligation was determined based upon the PCB regulations that originally became effective in 1978.

Non-Legal Liability — Cost of Removal

We recover in rates the costs to dispose of utility plant assets that do not represent legal retirement obligations. As of December 31, 2008 and 2007, we had $50.1 million and $25.2 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.

15. LEGAL PROCEEDINGS

In late 2002, two of our executive officers resigned or were placed on administrative leave from their positions. Our board of directors determined that their employment was terminated for cause. In June 2003, we filed a demand for arbitration with the American Arbitration Association asserting claims against them arising out of their previous employment and seeking to avoid payment of compensation not yet paid to them under various plans and agreements. They filed counterclaims against us alleging substantial damages related to the termination of their employment. As of December 31, 2008, we had accrued liabilities of $74.9 million for compensation not yet paid to them and $6.8 million for legal fees and expenses they have incurred. The arbitration has been stayed pending final resolution of criminal charges filed by the United States Attorney's Office against them in U.S. District Court in the District of Kansas. We intend to vigorously defend against the counterclaims they filed in the arbitration. We are unable to predict the ultimate impact of this matter on our consolidated financial statements.

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

See also Note 13, "Commitments and Contingencies."

16. GUARDIAN INTERNATIONAL PREFERRED STOCK

On March 6, 2006, Guardian International, Inc. (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 recognized a gain of approximately $0.3 million as a result of this transaction. A majority of these shares were beneficially owned by the two executive officers referred to in Note 15, "Legal Proceedings." The ownership of the shares they beneficially owned, as well as related dividends, and now the cash received for the shares, is disputed and is the subject of the arbitration proceeding discussed in Note 15, "Legal Proceedings." As a result of this transaction, we no longer hold any Guardian securities.

17. 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
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
Issuance of common stock	—	8,068,294
Balance at December 31, 2007	214,363	95,463,180
Issuance of common stock	—	12,847,955
Balance at December 31, 2008	214,363	108,311,135

Westar Energy's articles of incorporation, as amended, provide for 150,000,000 authorized shares of common stock. As of December 31, 2008, we had 108,311,135 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 2008, a total of 592,772 shares were issued by Westar Energy through the DSPP and other stock based plans operated under the 1996 LTISA Plan. As of December 31, 2008, a total of 3,862,038 shares were available under the DSPP registration statement.

Common Stock Issuance

On May 29, 2008, we entered into an underwriting agreement relating to the offer and sale of 6.0 million shares of the company's common stock. On June 4, 2008, we issued all 6.0 million shares and received $140.6 million in total proceeds, net of underwriting discounts and fees related to the offering.

On November 15, 2007, we entered into a forward sale agreement with a bank, as forward purchaser, relating to 8.2 million shares of our common stock. The forward sale agreement provides for the sale of our common stock within approximately twelve months at a stated settlement price. In connection with the forward sale agreement, the bank borrowed an equal number of shares of our common stock from stock lenders and sold the borrowed shares to another bank under an underwriting agreement among Westar Energy and the banks. The underwriters subsequently offered the borrowed shares to the public at a price per share of $25.25.

On December 28, 2007, we delivered 3.1 million newly issued shares of our common stock to a bank and received proceeds of $75.0 million as partial settlement of the forward sale agreement. Additionally, on February 7, 2008, we delivered 2.1 million shares and received proceeds of $50.0 million as partial settlement of the forward sale agreement. On June 30, 2008, we completed the forward sale agreement by delivering 3.0 million shares and receiving proceeds of $73.0 million.

On August 24, 2007, we entered into a Sales Agency Financing Agreement with a bank. Under the terms of the agreement, we may offer and sell shares of our common stock from time to time through the bank, as agent, up to an aggregate of $200.0 million for a period of no more than three years. We will pay the bank a commission equal to 1% of the sales price of all shares sold under the agreement. During 2007 we sold 0.8 million shares of common stock through the bank for $20.0 million and received $19.8 million in proceeds net of commission. During 2008 we sold 1.1 million shares of common stock through the bank for $26.9 million and received $26.7 million in proceeds net of commission.

On April 12, 2007, we entered into an earlier Sales Agency Financing Agreement with the same bank. As of July 12, 2007, we had sold 3.7 million shares of the company's common stock for $100.0 million pursuant to the agreement. We received $99.0 million in proceeds net of a commission.

We used the proceeds of stock issued to repay borrowings under Westar Energy's revolving credit facility, with those borrowed amounts principally related to our investments in capital equipment, as well as for working capital and general corporate purposes.

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, 2008.

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, including the proposed payment, during the 12-month period ending with and including the date of the proposed payment 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, during the 12-month period ending with and including the date of the proposed payment shall not exceed 75% 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. 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, 2008, 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 common 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.

18. 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 21 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:		
2006	$ 18,069	$ 32,107
2007	18,069	35,267
2008	18,069	38,870
Future commitments:		
2009	$ 32,964	$ 49,602
2010	33,041	47,283
2011	33,122	46,386
2012	33,209	48,387
2013	33,350	44,900
Thereafter	256,125	287,699
Total future commitments	$421,811	$524,257

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

The La Cygne unit 2 lease will expire in September 2029. Upon expiration, 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.

Capital Leases

We identify capital leases based on criteria in SFAS No. 13, "Accounting for Leases." For both vehicles and computer equipment, new leases are signed each month based on the terms of master lease agreements. The lease term for vehicles is from one to 14 years depending on the type of vehicle. Computer equipment has a lease term of two to four years.

On April 1, 2007, we completed the purchase of Aquila, Inc.'s (Aquila) 8% leasehold interest in Jeffrey Energy Center for $25.8 million and assumed the related lease obligation. This lease expires on January 3, 2019, and has a purchase option at the end of the lease term. Based on current economic and other conditions, we expect to exercise the purchase option. Based upon these expectations, we recorded a capital lease of $118.5 million.

Assets recorded under capital leases are listed below.

December 31,	2008	2007
	(In Thousands)	
Vehicles	$ 24,443	$ 27,132
Computer equipment and software	6,133	5,212
Jeffrey Energy Center 8% interest	118,538	118,538
Accumulated amortization	(22,526)	(20,576)
Total capital leases	$126,588	$130,306

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)
2009	$ 17,443
2010	15,930
2011	15,967
2012	11,920
2013	7,638
Thereafter	119,239
	188,137
Amounts representing imputed interest	(61,073)
Present value of net minimum lease payments under capital leases	127,064
Less current portion	9,155
Total long-term obligation under capital leases	$117,909

19. 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.

20. 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.

2008	First[a]	Second[b]	Third	Fourth[c]
	(In Thousands, Except Per Share Amounts)			
Sales[d]	$406,827	$451,219	$574,853	$406,097
Net income[d]	61,136	5,845	88,285	22,874
Earnings available for common stock[d]	60,894	5,603	88,043	22,632
Per Share Data[d]:				
Basic:				
Earnings available	$ 0.63	$ 0.06	$ 0.81	$ 0.21
Diluted:				
Earnings available	$ 0.62	$ 0.06	$ 0.81	$ 0.21
Cash dividend declared per common share	$ 0.29	$ 0.29	$ 0.29	$ 0.29
Market price per common share:				
High	$ 25.92	$ 24.65	$ 24.97	$ 24.80
Low	$ 21.75	$ 21.20	$ 20.82	$ 15.97

[a] *In the first quarter of 2008, we recognized a net earnings benefit of approximately $39.4 million, including interest, due to the recognition of previously unrecognized tax benefits.*

[b] *In the second quarter of 2008, net income and earnings available for common stock decreased due to lower energy marketing and extended planned outages at our base load plants.*

[c] *In the fourth quarter of 2008, we recognized a net earnings benefit of approximately $14.6 million from state tax incentives related to investment and jobs creation within the state of Kansas.*

[d] *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.*

2007	First	Second	Third	Fourth
	(In Thousands, Except Per Share Amounts)			
Sales[a]	$370,306	$415,178	$548,496	$392,854
Net income[a]	30,175	32,708	91,706	13,765
Earnings available for common stock[a]	29,933	32,466	91,464	13,523
Per Share Data[a]:				
Basic:				
Earnings available	$ 0.34	$ 0.36	$ 0.99	$ 0.15
Diluted:				
Earnings available	$ 0.34	$ 0.36	$ 0.99	$ 0.14
Cash dividend declared per common share	$ 0.27	$ 0.27	$ 0.27	$ 0.27
Market price per common share:				
High	$ 28.54	$ 28.57	$ 26.44	$ 26.83
Low	$ 25.23	$ 23.81	$ 22.84	$ 24.29

[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, 2008, our disclosure controls and procedures were effective at a reasonable assurance level 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. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by an issuer in the reports that it files or submits under the Act is accumulated and communicated to the issuer's management, including its principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

There were no changes in our internal control over financial reporting during the fourth quarter ended December 31, 2008, 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 2009 Annual Meeting of Shareholders to be filed pursuant to Regulation 14A (the 2009 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 2009 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 2009 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 2009 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 2009 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 2009 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, 2008 and 2007

Consolidated Statements of Income for the years ended December 31, 2008, 2007 and 2006

Consolidated Statements of Comprehensive Income for the years ended December 31, 2008, 2007 and 2006

Consolidated Statements of Cash Flows for the years ended December 31, 2008, 2007 and 2006

Consolidated Statements of Shareholders' Equity for the years ended December 31, 2008, 2007 and 2006

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
1(c)	—	Sales Agency Financing Agreement, dated as of April 12, 2007, between Westar Energy, Inc. and BNY Capital Markets, Inc. (filed as Exhibit 1.1 to the Form 8-K filed on April 12, 2007)	I
1(d)	—	Sales Agency Financing Agreement, dated as of August 24, 2007, between Westar Energy, Inc. and BNY Capital Markets, Inc. (filed as Exhibit 1.1 to the Form 8-K filed on August 27, 2007)	I
1(e)	—	Underwriting Agreement, dated November 15, 2007, among UBS Securities LLC and J.P. Morgan Securities Inc., as representatives of the underwriters named therein, UBS Securities LLC, in its capacity as agent for UBS AG, London Branch, and Westar Energy, Inc. (filed as Exhibit 1.1 to the Form 8-K filed on November 16, 2007)	I
1(f)	—	Underwriting Agreement, dated May 29, 2008, among Citigroup Global Markets Inc., Banc of America Securities LLC and UBS Securities LLC, as representatives of the underwriters named therein, and Westar Energy, Inc. (filed as Exhibit 1.1 to the Form 8-K filed on June 4, 2008)	I
1(g)	—	Underwriting Agreement, dated November 18, 2008, among J.P. Morgan Securities Inc. and Deutsche Bank Securities Inc., as representatives of the underwriters named therein, and Westar Energy, Inc. (filed as Exhibit 1.1 to the Form 8-K filed on November 24, 2008)	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
4(w)	—	Fortieth Supplemental Indenture dated May 15, 2007, between Westar Energy, Inc. and The Bank of New York Trust Company, N.A. (as successor to Harris Trust and Savings Bank) to its Mortgage and Deed of Trust dated July 1, 1939 (filed as Exhibit 4.16 to the Form 8-K filed on May 16, 2007)	I

4(x)	—	Forty-Eighth Supplemental Indenture, dated as of July 10, 2007, by and among Kansas Gas and Electric Company, The Bank of New York Trust Company, N.A. and Judith L. Bartolini (filed as Exhibit 4(x) to the Form 10-K for the period ended December 31, 2007 filed on February 29, 2008)	I
4(y)	—	Bond Purchase Agreement, dated as of August 14, 2007, between Kansas Gas and Electric Company and Nomura International PLC (filed as Exhibit 4.1 to the Form 8-K filed on August 15, 2007)	I
4(z)	—	Forty-Ninth Supplemental Indenture, dated as of October 12, 2007, by and among Kansas Gas and Electric Company, The Bank of New York Trust Company, N.A. and Judith L. Bartolini (filed as Exhibit 4.1 to the Form 8-K filed on October 19, 2007)	I
4(aa)	—	Form of First Mortgage Bonds, 6.10% Series Due 2047 (contained in Exhibit 4(w))	I
4(ab)	—	Bond Purchase Agreement dated as of May 15, 2008, between Kansas Gas and Electric Company and the Purchasers named therein (filed as Exhibit 4(1) to the Form 8-K filed on May 16, 2008)	I
4(ac)	—	Fifty-First Supplemental Indenture, dated as of May 15, 2008 by and among Kansas Gas and Electric Company, The Bank of New York Trust Company, N.A. and Judith L. Bartolini (filed as Exhibit 4(2) to the Form 8-K filed on May 16, 2008)	I
4(ad)	—	Fifty-Second Supplemental Indenture, dated as of August 1, 2008 by and among Kansas Gas and Electric Company, The Bank of New York Mellon Trust Company, N.A. and Judith L. Bartolini (filed as Exhibit 4(c) to the Form 10-Q for the period ended September 30, 2008 filed on November 6, 2008)	I
4(ae)	—	Fifty-Third Supplemental Indenture, dated as of October 10, 2008 by and among Kansas Gas and Electric Company, The Bank of New York Mellon Trust Company, N.A. and Judith L. Bartolini (filed as Exhibit 4(d) to the Form 10-Q for the period ended September 30, 2008 filed on November 6, 2008)	I
4(af)	—	Forty-First Supplemental Indenture, dated as of November 25, 2008 by and among Westar Energy, Inc., The Bank of New York Mellon Trust Company, N.A. and Judith L. Bartolini (filed as Exhibit 4.1 to the Form 8-K filed on November 24, 2008)	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
10(ap)	—	Confirmation of Forward Sale Transaction, dated November 15, 2007, between UBS AG, London Branch and Westar Energy, Inc. (filed as Exhibit 10.1 to the Form 8-K filed on November 16, 2007)	I
10(aq)	—	Third Amended and Restated Credit Agreement dated as of February 22, 2008, among Westar Energy, Inc., and 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 February 26, 2008)	I
12(a)	—	Computations of Ratio of Consolidated Earnings to Fixed Charges	#
12(b)	—	Computation of Ratio of Earnings to Fixed Charges for the Three Months Ended March 31, 2007 (filed as Exhibit 12.1 to the Form 8-K filed on May 10,2007)	I
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
99(j)	—	Westar Energy, Inc. Form of Restricted Share Units Award (filed as Exhibit 99.1 to the Form 8-K filed on December 19, 2006)	I
99(k)	—	Stipulation and Agreement filed with the Kansas Corporation Commission on October 27, 2008 (filed as Exhibit 99.1 to the Form 8-K filed on October 27, 2008)	
99(l)	—	Civil complaint filed by the United States Department of Justice on February 4, 2009 (filed as Exhibit 99.1 to the Form 8-K filed on February 5, 2009)	

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, 2006				
Allowances deducted from assets for doubtful accounts	$5,233	$5,091	$(4,067)	$6,257
Year ended December 31, 2007				
Allowances deducted from assets for doubtful accounts	$6,257	$3,273	$(3,809)	$5,721
Year ended December 31, 2008				
Allowances deducted from assets for doubtful accounts	$5,721	$3,580	$(4,491)	$4,810

[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: February 27, 2009

By: /s/ Mark A. Ruelle

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

SIGNATURES

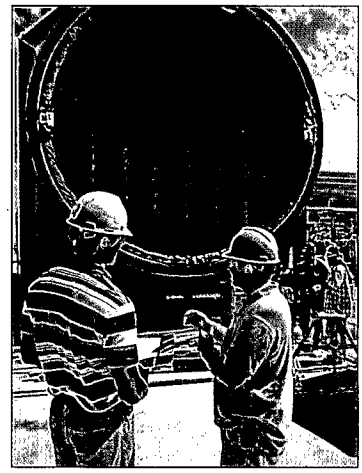
Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

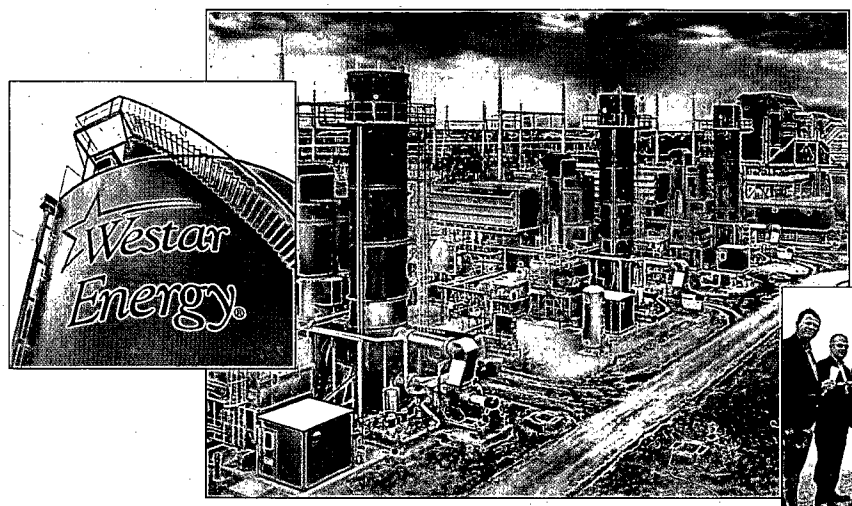
Signature	Title	Date
/s/ WILLIAM B. MOORE (William B. Moore)	Director, President and Chief Executive Officer (Principal Executive Officer)	February 27, 2009
/s/ MARK A. RUELLE (Mark A. Ruelle)	Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	February 27, 2009
/s/ CHARLES Q. CHANDLER IV (Charles Q. Chandler IV)	Chairman of the Board	February 27, 2009
/s/ MOLLIE H. CARTER (Mollie H. Carter)	Director	February 27, 2009
/s/ R. A. EDWARDS III (R. A. Edwards III)	Director	February 27, 2009
/s/ JERRY B. FARLEY (Jerry B. Farley)	Director	February 27, 2009
/s/ B. ANTHONY ISAAC (B. Anthony Isaac)	Director	February 27, 2009
/s/ ARTHUR B. KRAUSE (Arthur B. Krause)	Director	February 27, 2009
/s/ SANDRA A. J. LAWRENCE (Sandra A. J. Lawrence)	Director	February 27, 2009
/s/ MICHAEL F. MORRISSEY (Michael F. Morrissey)	Director	February 27, 2009
/s/ JOHN C. NETTELS, JR. (John C. Nettels, Jr.)	Director	February 27, 2009

WINDS OF CHANGE

EMPORIA ENERGY CENTER

Construction of the natural gas-fired power plant, Emporia Energy Center, located northeast of Emporia, KS, was completed ahead of schedule and under budget. It was originally estimated that the plant would produce 610 megawatts, but the performance of units currently online exceeded expectations and the plant is now rated at 665 megawatts. Construction was complete in late February 2009 which was about two months earlier than planned.



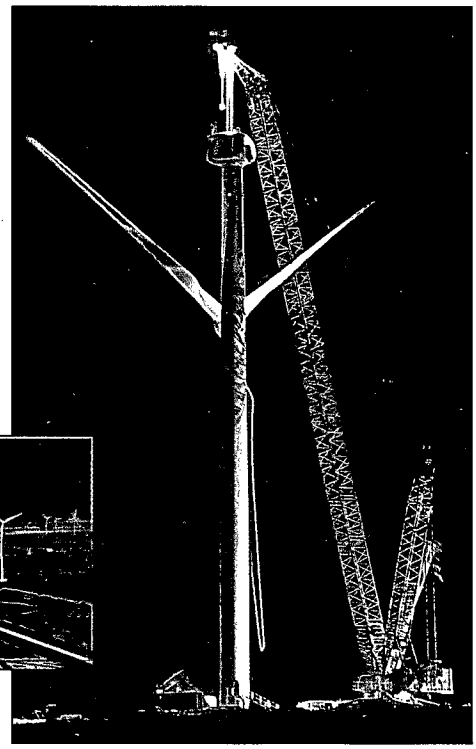


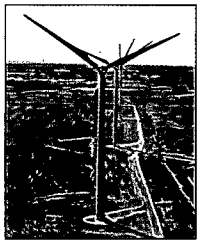
RENEWABLE ENERGY

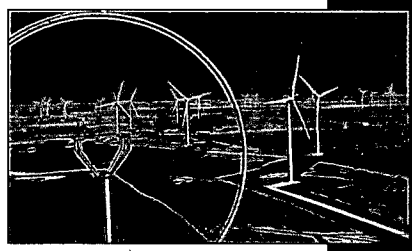
In 2007, we launched the state's largest wind energy program of its kind with the construction of three wind farms, bringing nearly 300 megawatts of clean, renewable energy to the grid.

We own the Central Plains Wind Farm near Leoti in Wichita County; we own half of the wind turbine generators at the Flat Ridge facility, located near Medicine Lodge in Barber County, and purchase the generation from the remaining turbines under contract; and we purchase power produced at the Meridian Way facility in Cloud County south of Concordia.

In February 2009 we announced that we are looking to add up to 500 MW of additional renewable energy to our generation portfolio to help meet our renewable energy goals as well as continue to meet our customers' energy needs.







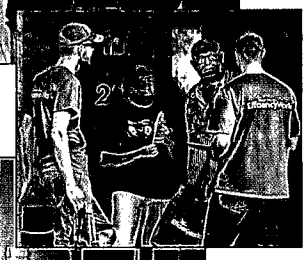
ENERGY EFFICIENCY

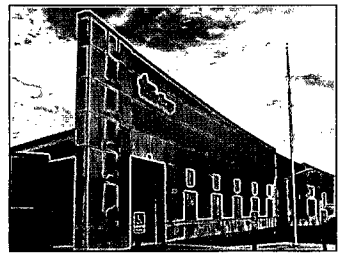
At Westar Energy, we believe it's important to work with our customers as partners to make sure we are all using energy effectively and efficiently. Energy efficiency initiatives can help delay the need for more costly, base load generation as well as reduce the negative impact on our environment. Through educational programs, community presentations and Web site tools, we're reaching every age group, from schoolchildren to retirees, giving them simple solutions to curb energy use.

In 2008, we provided 400 weatherization kits to customers throughout our service territory; gave more than 90 energy efficiency presentations to schoolchildren; and launched the Colwich Switch, a year-long energy-savings study of an entire community. The study looks at the effects of households installing compact fluorescent light bulbs as well as adopting energy saving measures suggested by Westar's energy efficiency department. We will announce results of the year-long study this fall.

Our operations center in Lawrence was renovated in 2008 using design criteria that meets the U.S. Green Building Council's Leadership in Energy and Environmental Design Green Building Rating System.

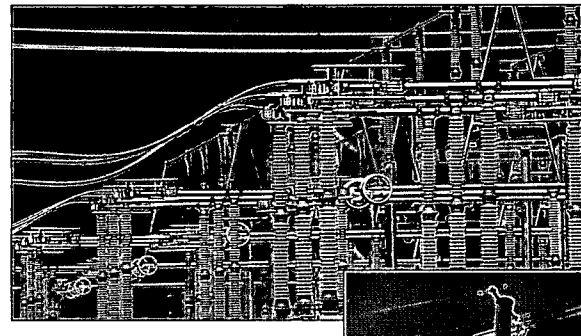
The facility includes efficient lighting and controls, a geothermal heat pump system, and the use of local and regional resources for much of the building's materials that adhere to national benchmarks for sustainable design and construction in green buildings.

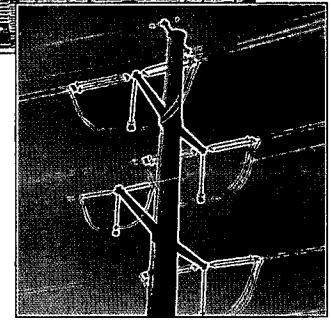


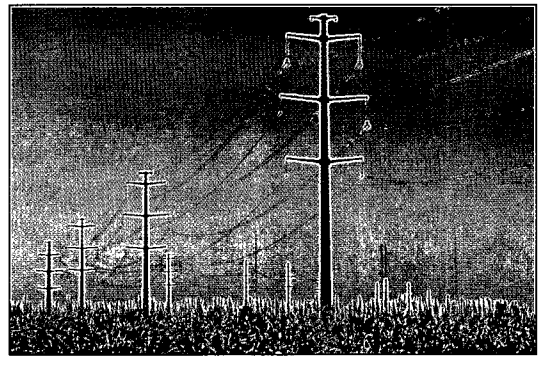


TRANSMISSION

We are committed to expanding our transmission network to serve Kansas and the region well into future decades. In December, we completed construction of a 345 kilovolt transmission line from our Gordon Evans Energy Center near Wichita to a new Reno County Substation near Hutchinson. This first phase of the Wichita to Reno County to Salina line was completed ahead of schedule. Phase two, which extends the line from the Reno County Substation to the Summit Substation near Salina is underway. We also have plans to build a 345 kV line from our Rose Hill Substation south of Wichita to the Oklahoma border where it will meet up with a line being built by Oklahoma Gas & Electric. In 2008, Westar and Electric Transmission America formed Prairie Wind Transmission, LLC, a joint venture company that has plans to construct ultra-high capacity electric transmission facilities in Kansas.

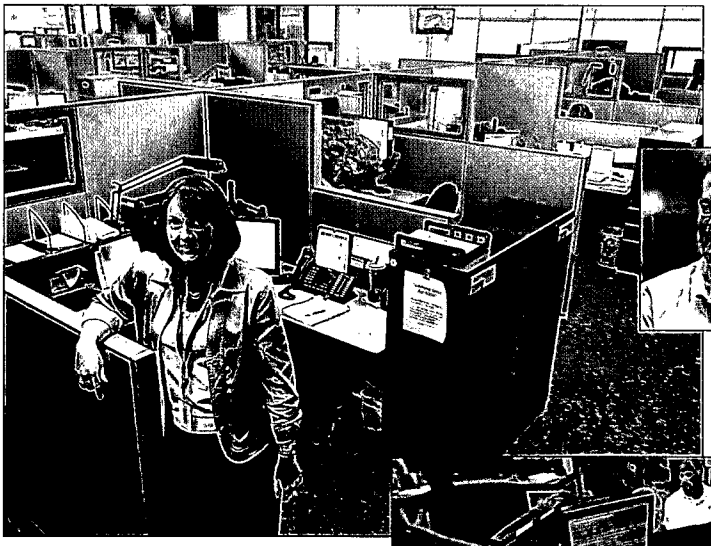


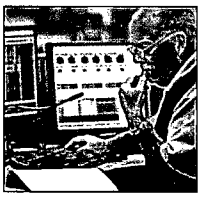


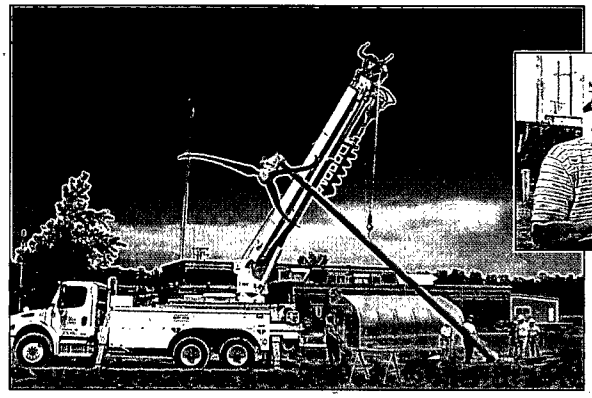


EMPLOYEE COMMITMENT

Today, more than ever, we recognize the importance of having dependable employees who share our mission of providing customers safe and reliable electricity. Nearly 2,400 employees are intertwined throughout the communities in our service territory, working in plants, service centers, offices and substations. Our employees understand the value of a dollar, hard work, dedication and the drive for success, and it shows. In 2008, through the company's corporate gift and employee pledges, we raised more than $539,000 for 19 United Way organizations in our service territory. And that's just the beginning. With programs such as the Westar Energy Green Team, School Connections and our Community Relations Teams, employees are able to merge their talents and interests in ways that benefit their communities.







SHAREHOLDER INFORMATION AND 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

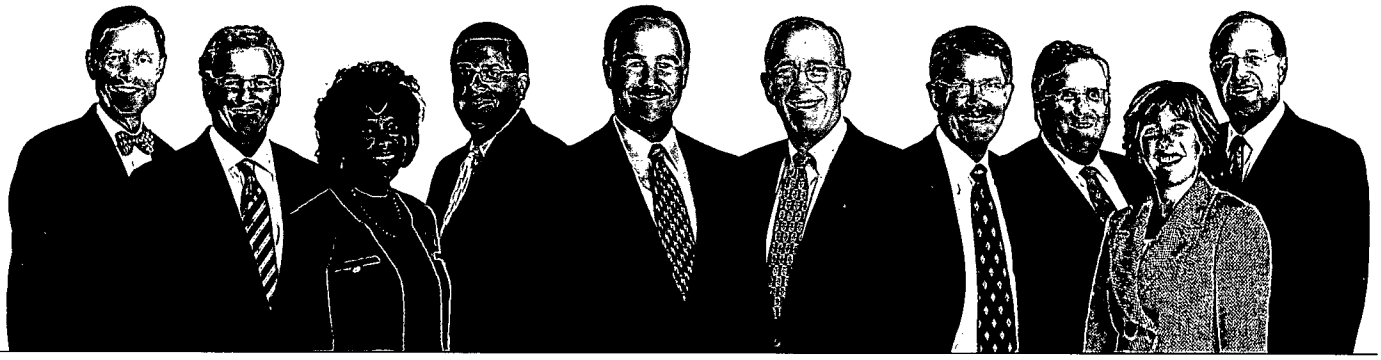
Ticker Symbol (NYSE): WR

Daily Stock Table Listing: WestarEngy

CHIEF EXECUTIVE OFFICER AND CHIEF FINANCIAL OFFICER CERTIFICATIONS

In 2008 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, 2008, were included as exhibits to Westar Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2008, that was filed with the Securities and Exchange Commission.

DIRECTORS:



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

CHARLES Q. CHANDLER IV (55)
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 (46)
Director since 2003
Chairman of the Board, President and Chief Executive Officer
Sunflower Banks, Inc.
Salina, Kansas
Committees: Compensation, Finance

R.A. EDWARDS III (63)
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 (62)
Director since 2004
President
Washburn University
Topeka, Kansas
Committees: Audit, Nominating and Corporate Governance

B. ANTHONY ISAAC (55)
Director since 2003
President
LodgeWorks, LP
Wichita, Kansas
Committees: Compensation, Finance

ARTHUR B. KRAUSE (67)
Director since 2003
Executive Vice President and Chief Financial Officer (Retired)
Sprint Corporation
Naples, Florida
Committees: Audit, Finance

SANDRA A.J. LAWRENCE (51)
Director since 2004
Executive Vice President and Chief Financial Officer
Children's Mercy Hospital
Kansas City, Missouri
Committees: Compensation, Nominating and Corporate Governance

WILLIAM B. MOORE (56)
Director since 2007
President and Chief Executive Officer
Westar Energy, Inc.
Topeka, Kansas

MICHAEL F. MORRISSEY (66)
Director since 2003
Managing Partner (Retired)
Ernst & Young LLP
Naples, Florida
Committees: Audit, Compensation

JOHN C. NETTELS, JR. (52)
Director since 2000
Partner
Stinson Morrison Hecker LLP
Overland Park, Kansas
Committee: Finance

OFFICERS:

WILLIAM B. MOORE (56)
28 years of service
Director, President and Chief Executive Officer

DOUGLAS R. STERBENZ (45)
11 years of service
Executive Vice President and Chief Operating Officer

MARK A. RUELLE (47)
16 years of service
Executive Vice President and Chief Financial Officer

JAMES J. LUDWIG (50)
18 years of service
Executive Vice President, Public Affairs and Consumer Services

BRUCE AKIN (44)
21 years of service
Vice President, Operations Strategy and Support

JEFF BEASLEY (50)
31 years of service
Vice President, Corporate Compliance and Internal Audit

GREG A. GREENWOOD (43)
15 years of service
Vice President, Generation Construction

KELLY B. HARRISON (50)
27 years of service
Vice President, Transmission Operations and Environmental Services

LARRY D. IRICK (52)
9 years of service
Vice President, General Counsel and Corporate Secretary

KENNETH C. JOHNSON (55)
7 years of service
Vice President, Generation

MICHAEL LENNEN (63)
2 years of service
Vice President, Regulatory Affairs

PEGGY S. LOYD (51)
30 years of service
Vice President, Customer Care

ANTHONY D. SOMMA (45)
14 years of service
Treasurer

LEE WAGES (60)
31 years of service
Vice President, Controller

CAROLINE A. WILLIAMS (52)
33 years of service
Vice President, Distribution Power Delivery

Ages and years of service are as of December 31, 2008.

Westar Energy®

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

GREAT PLAINS℠
ENERGY

The energy of smart choices.

Great Plains Energy 2008 Annual Report

From meeting the challenges of a turbulent marketplace to growing our generating capabilities and customer base, Great Plains Energy is positioned to deliver low-cost, reliable service to our customers and growth to our shareholders.

Headquartered in Kansas City, Mo., Great Plains Energy Incorporated (NYSE: GXP) is the holding company of Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company, two of the leading regulated providers of electricity in the Midwest. Kansas City Power & Light and KCP&L Greater Missouri Operations use KCP&L as their brand name.

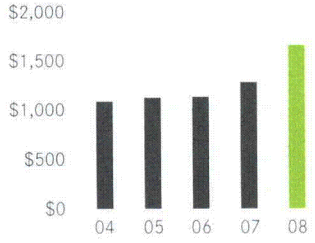
Top Photo: When the new Iatan 2 generating station comes online in 2010, it will complete the major portion of our five-year Comprehensive Energy Plan (CEP). The CEP was initiated in 2005 and is designed to help meet the growing demand for electricity in our region while delivering significant economic and environmental benefits to the Kansas City area. With over 2,500 skilled craftsmen working at the site, the Iatan project is the largest non-highway construction project currently in Missouri.

Selected Financial Data

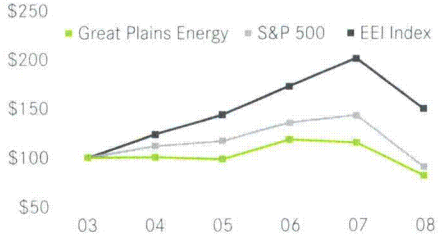
Year Ended December 31 (Dollars in millions except per share amounts)	**2008**	2007	2006	2005	2004
Great Plains Energy (a)					
Operating revenues	$ 1,670	$ 1,293	$ 1,140	$ 1,131	$ 1,092
Income from continuing operations (b)	$ 120	$ 121	$ 137	$ 135	$ 132
Net income	$ 155	$ 159	$ 128	$ 162	$ 183
Basic earnings per common share from continuing operations	$ 1.16	$ 1.41	$ 1.74	$ 1.79	$ 1.81
Basic earnings per common share	$ 1.51	$ 1.86	$ 1.62	$ 2.15	$ 2.51
Diluted earnings per common share from continuing operations	$ 1.16	$ 1.40	$ 1.73	$ 1.79	$ 1.81
Diluted earnings per common share	$ 1.51	$ 1.85	$ 1.61	$ 2.15	$ 2.51
Total assets at year-end	$ 7,869	$ 4,832	$ 4,359	$ 3,842	$ 3,796
Total redeemable preferred stock, mandatorily redeemable preferred securities and long-term debt (including current maturities)	$ 2,627	$ 1,103	$ 1,142	$ 1,143	$ 1,296
Cash dividends per common share	$ 1.66	$ 1.66	$ 1.66	$ 1.66	$ 1.66
SEC ratio of earnings to fixed charges	2.26	2.53	3.50	3.09	2.77
Kansas City Power & Light Company					
Operating revenues	$ 1,343	$ 1,293	$ 1,140	$ 1,131	$ 1,092
Net income	$ 125	$ 157	$ 149	$ 144	$ 145
Total assets at year-end	$ 5,229	$ 4,292	$ 3,859	$ 3,340	$ 3,335
Total redeemable preferred stock, mandatorily redeemable preferred securities and long-term debt (including current maturities)	$ 1,377	$ 1,003	$ 977	$ 976	$ 1,126
SEC ratio of earnings to fixed charges	2.87	3.53	4.11	3.87	3.37

(a) Great Plains Energy's results include GMO only from the July 14, 2008, acquisition date.
(b) This amount is before income (loss) from discontinued operations, net of income taxes, of $35.0 million, $38.3 million, $(9.1) million, $27.2 million and $50.3 million in 2008 through 2004, respectively.

Great Plains Energy Operating Revenues
(Dollars in Millions)

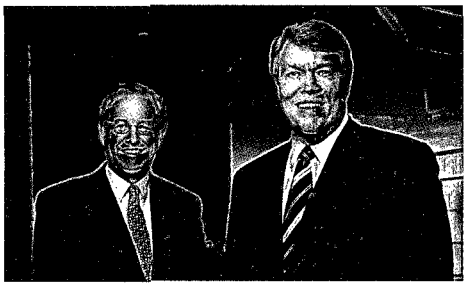


Stock Performance Graph
(Dollars)
Comparison of Cumulative Total Returns* of Great Plains Energy, S&P 500 Index and EEI Index



*Total return assumes reinvestment of dividends. Assumes $100 invested on December 31, 2003, in Company common stock, S&P 500 Index and EEI Index.

Letter to Shareholders



Bill Downey, President and Chief Operating Officer (left) and
Mike Chesser, Chairman of the Board and Chief Executive Officer

A Year of Transformation

2008 was a transformational year. We took proactive steps to improve our business risk profile with the sale of Strategic Energy, a competitive retail electric provider. Even more noteworthy, we expanded our utility platform and earnings potential by completing the acquisition of Aquila, with its Missouri-regulated utility business, and worked to complete the first of two major projects at our Iatan Generating Station.

We are in the final two years of our Comprehensive Energy Plan (CEP). Under the CEP, we have added a new wind farm in western Kansas, installed environmental equipment at our LaCygne 1 and Iatan 1 coal plants, invested in our transmission and distribution system and launched a number of energy-efficiency and demand-response programs. And finally, construction is continuing on Iatan 2, an 850-megawatt, coal-fired power plant featuring state-of-the-art emission-control equipment. Our ownership share of Iatan 2 is 73 percent. With a planned completion date in the summer of 2010, Iatan 2 is expected to provide clean, reliable energy for our region for years to come.

We are proud of these accomplishments. It is a tribute and testament to our dedicated, hard-working employees.

Stock Price Performance

While we accomplished much in 2008, our achievements were not reflected in our stock price performance last year. For the year, our price fell 34.1 percent, which was greater than the Philadelphia Stock Exchange Utility Index's decline of 29.9 percent, but less than the S&P 500's drop of 38.5 percent. We believe the reasons our stock price underperformed in 2008 include: the long construction period for our CEP, the uncertainty in the first half of 2008 that surrounded the sale of Strategic Energy and the acquisition of Aquila, and the impact of the volatile economy and financial markets on our actual and projected results and financing plans.

Dividend

To provide the Company additional financial flexibility, in February 2009 we announced a 50 percent reduction in our common stock dividend. Our previous level of dividend and stock price had resulted in a dividend yield that was the highest in the utility industry. Also, the payout ratio with the previous dividend level would have resulted in us paying out well over 100 percent of projected 2009 earnings. Reducing the dividend by half will save our Company about $100 million per year in cash that can be reinvested in our business and reduce our reliance on expensive external capital, while still maintaining yield and payout ratios that are competitive with other utilities.

We know that our dividend is an important part of the value proposition for owning our stock. However, during these extremely challenging times, we believe our shareholders' long-term interests are best served by maintaining the Company's financial strength and flexibility to ensure continued progress toward our long-term objectives.

The dividend reduction is just one of several proactive steps we are taking to meet the economic and market challenges head-on. We continue to work to capture the promised synergies of the Aquila transaction. Additional steps we have initiated include:

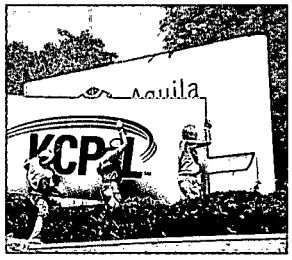
- eliminating or deferring $450 million of capital spending over the next two years; and
- suspending external hiring for all but essential skills.

We believe that these actions will allow us to continue with our strategic growth plan and emerge from these difficult times a strong company.

2008 Strategic Accomplishments

June 2008: Sold Strategic Energy and received about $300 million in cash, which was reinvested in our utility operations. The sale value looked very attractive then and looks even more so now, given developments in the competitive supply market over the past several months.

July 2008: Acquired Aquila (now named KCP&L Greater Missouri Operations Company, or GMO) following a 17-month approval process and immediately began integrating the operations to begin capturing the benefits for shareholders and customers. In today's rising-cost environment, the synergies we expect to achieve from this transaction are an important part of our plan to maintain affordable energy prices for the customers and communities we serve.



September 2008: Filed rate cases with the Missouri Public Service Commission (MPSC) and the Kansas Corporation Commission (KCC) to increase base rates in all of our utility service areas. The requests, which are subject to regulatory approval, are expected to be decided in late summer of 2009. The rate requests vary in each of our service areas and include recovery for investments in environmental upgrades at our Iatan 1 and Sibley 3 power plants, Crossroads generation and transmission resources and energy-efficiency programs, as well as overall increased costs of service.

October 2008: Initiated the Iatan 1 outage to perform a major unit overhaul, as well as the tie-in of the Air Quality Control System (AQCS) environmental project that is part of the CEP. The AQCS project was completed in February 2009. Iatan 1 is expected to return to normal operation early in the second quarter of 2009.

December 2008:

- **Successfully completed the environmental** Selective Catalytic Reduction (SCR) **upgrade** at Sibley 3 coal plant.
- **JD Power** confirmed **customer satisfaction** remained **strong.** Despite recent rate increases, our overall prices remain approximately 25 percent below the national average.

Positioning for the Future

The global energy arena is facing a time of uncertainty that will undoubtedly bring much change. It is difficult to predict the industry consequences of the shift in global and national energy and environmental policy, the advancements in enabling technologies and the broad-based energy efficiency initiatives that are underway. But it is clear that the electric energy industry must explore a variety of supply resources including nuclear power, clean coal, renewable resources such as wind and solar, and the storage of electric energy. We must also provide greater transparency and control to our customers over their energy usage. Each of these initiatives requires investment in infrastructure and enabling technologies.

In 2009, as we work on our remaining CEP projects and capture the synergies we have promised from the Aquila transaction, we also will develop the next phase of our strategic planning, the Sustainable Resource Strategy (SRS). As we did in the past with the CEP, the SRS initiative will engage the regulators, community and other key stakeholders in a process to help guide our long-term plans for generation, environmental spending, energy efficiency and renewable energy.

Financial Flexibility

We cannot know with any certainty what impact the continued difficulties in the global capital markets and the slowdown in the economy will have on our ability to tackle these significant infrastructure and environmental investments. But we do know that our proactive planning has better positioned us to complete the investments outlined in our CEP and respond to the changing energy and environmental policies and the marketplace. We're committed to manage our business and access the capital markets in a way that maintains our credit ratings and protects financial flexibility.

We're taking important steps to seize opportunities created by new directions in energy policy and to weather the current financial market turmoil. Guided by our strategic intent to provide long-term shareholder value and to improve the total living environment of our communities, we strive to be the place to work, the neighbor to have and the company to own.

Thank you for your support.

Mike Chesser

Bill Downey

2008 Focus on Our Utility Roots

The sale of Strategic Energy has enabled us to fully concentrate our energies on our regulated public utilities. With the completion of the Aquila transaction in July, the Company expanded its utility foundation and broadened its regional presence. We've renamed Aquila as KCP&L Greater Missouri Operations Company (GMO).

On the day the GMO acquisition was completed (July 14, 2008), we rebranded all utility locations with a new logo that represents today's KCP&L – a strong regional utility. Since Day One, employees have worked tirelessly to provide customers with seamless service as a single, operationally integrated organization.

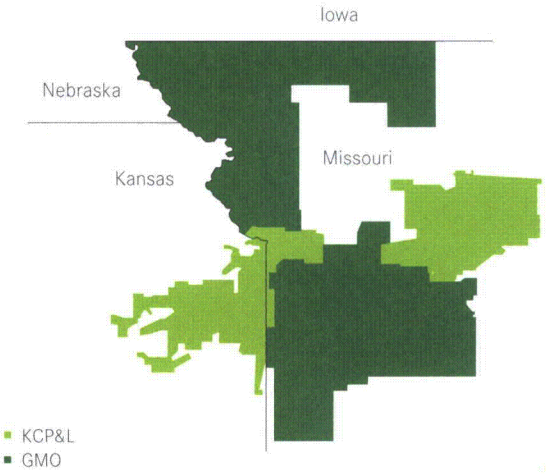
Our integration efforts focused on bringing together more than 820,000 customers across 47 counties; coordinating the operations of nearly 3,200 employees, 30 percent of which came from GMO; and ensuring reliable service across our expanded network.

Highlights include:

- Consolidating the two GMO unions into our three existing unions under common work rules.
- Combining two separate company platforms for accounting, HR systems, and telecom and network infrastructure into a single platform for each function.
- Managing the integration process to deliver immediate and sustainable synergy benefits. In our ongoing rate cases in Missouri, we included operating synergies that will begin accruing to Missouri customers when new rates are effective in the third quarter this year.

We're also already seeing the impact of extending our operational and reliability best practices to the GMO operations. The results from the fourth quarter JD Power Residential Customer Satisfaction survey showed continued improvement in the GMO territory, and the combined utilities placed in Tier 1 for the calendar year of 2008. Customer service outage duration statistics also continued to be good for the fourth quarter, and we anticipate our utilities will be top tier for the full year.

Service Territory



Utility Stats

Combined generation capacity of more than 6,137 MW: 3,177 MW of coal; 545 MW of nuclear; 101 MW of wind; and 2,314 MW of gas and oil.

42 facilities including the Company headquarters, 15 generating facilities, one wind generation facility, one nuclear facility, a data center, a customer-care center, a training center, an operations center and 20 service centers.

Over 820,000 customers including approximately 722,000 residences, 96,000 commercial firms and 2,800 industrials, municipalities and other electric utilities.

Network of over 3,000 miles of transmission lines, over 24,000 miles of distribution lines and 320 substations.

Benefits of the GMO Acquisition

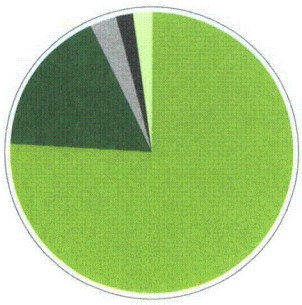
Significant customer and shareholder value: More than $750 million in gross estimated savings from operational synergies expected from 2008-2017.

Tier 1 operations: The adjacent utility service territories are helping create significant savings that support our goals of providing Tier 1 service and operational excellence.

Increased community presence: The acquisition expands the scope of our volunteerism, which helps build strong communities for our customers.

Diverse Generation Mix

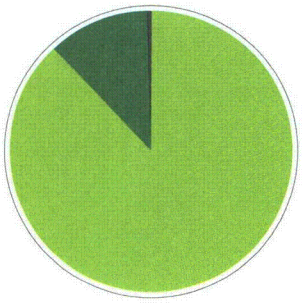
Net MWh's Generated by Fuel Type



- Coal 76%
- Nuclear 17%
- Coal and Natural Gas 3%
- Natural Gas and Oil 2%
- Wind 2%

Stable Regulated Customer Base

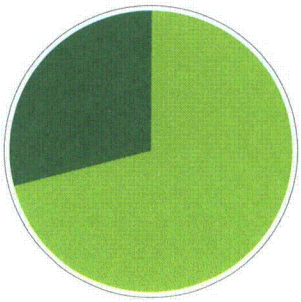
Serve Approximately 820,000 Customers



- Residences 722,000
- Commercial Firms 96,000
- Industrial, Municipalities and Other 2,800

Reliability a Key Focus

Expansive Distribution System



- Overhead Line Miles 71%
- Underground Line Miles 29%

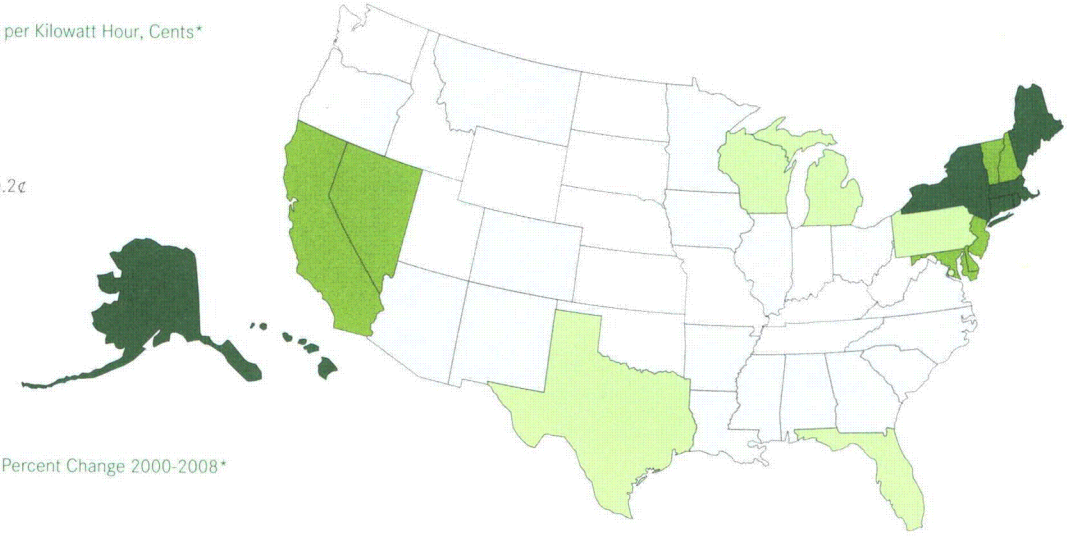
Providing Great Value

Missouri and Kansas have some of the lowest retail rates in the nation

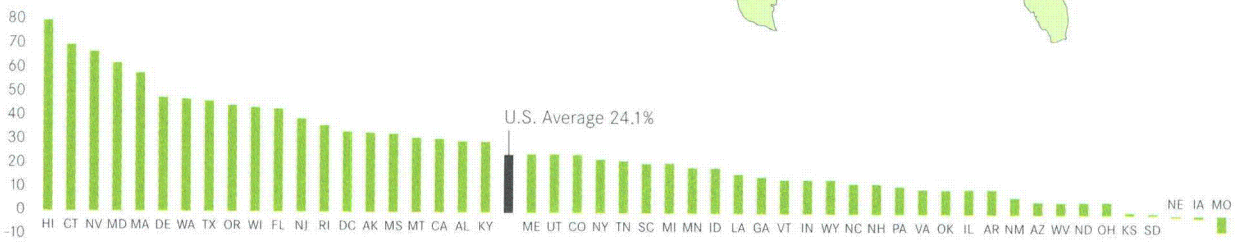
2008 Retail Price per Kilowatt Hour, Cents*

- 15.0 - 29.9
- 12.0 - 14.9
- 10.0 - 11.9
- 8.0 - 9.9
- 6.0 - 7.9

U.S. Average 10.2¢



Electricity Prices, Percent Change 2000-2008*



Business Week, July 24, 2008

Smart Choices Position Us for the Future

The industry is changing at a rapid pace and it is important to stay abreast and be involved in shaping the future energy landscape. We have consistently been at the forefront of environmental initiatives, advancements in enabling technologies and broad-based, energy efficiency efforts.

Mike Chesser, our Chairman and CEO, has taken a national role in energy technologies through his chairmanship of the Electric Power Research Institute's (EPRI) Board of Directors. Mike is also a member of the executive committee of the Edison Electric Institute (EEI) and chair of the Energy Efficiency Task Force, which is looking for ways to make energy efficiency a viable alternative for utilities around the country.

The evolution toward a smart grid is expected to be an important part of our Sustainable Resource Strategy (SRS) for 2010-2020. Kansas City Power & Light was an early adopter of an automated meter-reading system, and we are actively planning for investments in a two-way interactive system. Such a system will allow us to better communicate with our customers and manage the flow of electricity on the grid. A smart grid will enable and optimize the integration of distributed generation, provide better grid reliability and offer consumers more transparency and control of their energy usage.

We remain committed to delivering lower-cost energy in a volatile economy while addressing important environmental issues. As part of our CEP, we added 100.5 MW of wind generation in 2006. And as pledged, we are exploring additional wind-generation development and have introduced a number of initiatives focused on energy efficiency, demand response and affordability.

We have also invested in environmental upgrades and retrofits at four of our existing facilities. With these environmental enhancements, we will materially reduce total emissions of sulfur dioxide, nitrogen oxide, particulates and mercury across our entire fleet – and even with the addition of Iatan 2, we expect to see substantial reductions of these emissions from pre-CEP levels.

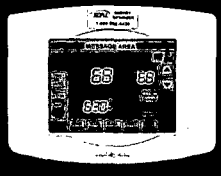
We continue to be a national leader in energy efficiency and are supporting proposed legislation to better enable consumers to lower their utility bills through increased energy efficiency, while also allowing a return on investment to our shareholders. This proposed legislation offers opportunities to replace capital expenditures on new plants with customer-oriented service incentives to use electricity more efficiently.

"It was KCP&L's leadership in creating a program to assist in offsetting some of the additional costs builders incur when constructing a more energy efficient home that has paved the way for better practices among builders. And it also serves as a template for other utility companies and municipalities as they create their own programs."

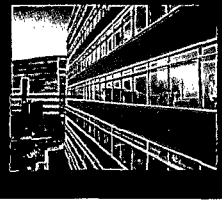
Kevin Enyeart, Chairman,
Build Green Council, Home Builders Association of Greater Kansas City

"We are working on a national level to ensure that shareholders are able to benefit from energy efficiency initiatives in the same way they would if we were building a power plant."

Mike Poling, Manager Government Affairs,
Washington D.C.



KCP&L's free Honeywell programmable *thermostat – a $300 value – produces* an average energy savings of up to 20 percent annually.



The MPower program pays *businesses to reduce their usage* a few times a year when peak summer demand would otherwise raise all rates or cause brownouts.

We're Proactively Meeting the Industry's Top Challenges

Electricity will remain the backbone of the nation's economy. There are many challenges and opportunities facing the electricity sector that we will need to address in collaboration with all stakeholders.

Industry Challenges	Our Strategies
The ability to access capital in order to continue investments in energy infrastructure and technology	We have eliminated or deferred $450 million of capital spending over the next two years. We have also reduced the dividend 50 percent and will reinvest the funds back into the Company, thus lowering external financing needs. And we are working to capture the synergies of the GMO acquisition.
Costs are increasing and near-term demand is decreasing	The GMO acquisition expanded our customer base and is providing synergy opportunities. We're focused on reducing operating expenses toward Tier 1 levels across our Company. And we are also supporting legislation that would compensate utilities for energy efficiency investments.
Aging workforce	We have assisted the Kansas City Metropolitan Community College in creating an associate's degree program for utility line technicians. We also helped form the National Utility Industry Training Fund, a joint venture between KCP&L, the IBEW and two other utilities. This fund will support regional training centers for existing and potential linemen throughout the United States, and KCP&L eventually will host one of these regional centers.
Increasing environmental regulations	CEP projects are proactive steps to address environmental regulations. KCP&L's efforts to significantly cut emissions that contribute to ground-level ozone have generated both local and national recognition of environmental stewardship.
Transmission and distribution system is becoming more congested	We will maintain and improve our top-tier reliability by continuing the construction of new and/or replacement and upgrading of existing transmission and distribution facilities, and installing new technologies for faster diagnosis and repair of service interruptions.
The ability for companies to make long-term investments to better serve customers and, in the process, allow investors to earn a reasonable return on their investment	We will continue to work closely with our legislative and regulatory bodies on the implementation of constructive policies that support a variety of alternatives for responding to the changing industry dynamics. We continue to work with all of our constituencies as we plan for the future through the development of our new Sustainable Resource Strategy (SRS) for 2010-2020.

The Power of Partnering

We are committed to building a Winning Culture that values inspired leadership, disciplined performance management, engaged employees, accountability and loyalty. We believe the right team will produce performance that will drive long-term shareholder and customer value.

Partnering is a Winning Culture fundamental. It is reflected in almost everything we do – from our relationships with customers, suppliers and the communities we serve to the handling of the GMO integration. Winning Culture is an inclusive program designed to help employees develop professionally and feel a kinship as we work together to build a top-tier organization. It very much includes our relationship with the leadership of the International Brotherhood of Electrical Workers (IBEW), who worked with us to consolidate GMO's two unions into our three existing unions. Bargaining unit employees are valued members of our Company and are active on our Winning Culture Partner teams, which are volunteer groups focused on identifying and implementing process improvements across the Company.

We remain firmly committed to our community, legislative and regulatory approach, because we have learned that each constituency supports and influences the others. Through this approach, we have built numerous collaborative relationships that help us accomplish our business objectives and also serve as a good corporate citizen.

Our targeted volunteer and charitable support programs focus on at-risk youth, the environment and economic and civic efforts. We are building strong, long-term relationships with customers, community leaders, legislators and regulators, which ultimately impact shareholder value.

"Our Winning Culture provides our greatest long-term sustainable advantage. It's what differentiates us from many other utilities."

Mike Chesser, CEO

2008 Community Strategy Highlights

Employee volunteerism reached 20 percent (over the target of 18 percent).

Expansion of Community Strategy into new communities through giving, volunteerism and leadership.

Top leadership met with more than 600 community leaders and customers at 11 events in new territories to discuss integration and important issues.

United Way Campaign: record-breaking $1,027,173 with 55 percent of Company participating. 17 GMO locations held campaigns for the first time. **Leadership givers** increased to 133 (40 percent increase).

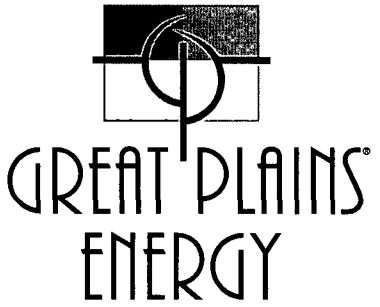
Company leadership grew with representation on 100 boards, including 14 in the GMO service area (87 percent of our key partners have representation).

Community involvement and leadership awards: KC Spirit Award, KC Business Journal – Champions of Business Award, Harvester's Hall of Fame Award, Habitat for Humanity Company of the Year, Urban League Difference Maker Award.

KCP&L Energizers Program

We adopted a GMO best practice for the entire Company when we introduced the **KCP&L Energizers** peer-nominated employee recognition program. The first outstanding employee to be recognized was Materials Operator **Rob Hull,** IBEW 1464, who in 2008 introduced and implemented an idea that saved more than $25,000 in contractor fees. He also recommended a safety procedure to reduce accidents by increasing motorist visibility of pole trucks.

In 2008, we sent more than 100 employees to assist utilities in St. Louis, Mo.; Houston, Texas; and Greenville and Louisville, Ky. with Hurricane Ike damage repairs. Their dedication was widely recognized by the host utilities.



GREAT PLAINS ENERGY INCORPORATED

1201 WALNUT STREET
KANSAS CITY, MISSOURI 64106

March 25, 2009

Dear Shareholder:

We are pleased to invite you to the Annual Meeting of Shareholders of Great Plains Energy Incorporated. The meeting will be held at 10:00 a.m. (Central Daylight Time) on Tuesday, May 5, 2009, at the Kansas City Public Library Plaza Branch, Truman Forum Auditorium, 4801 Main Street, Kansas City, Missouri 64112. The Truman Forum Auditorium is accessible to all shareholders. **Shareholders with special assistance needs should contact the Corporate Secretary, Great Plains Energy Incorporated, 1201 Walnut Street, Kansas City, Missouri 64106, no later than Friday, April 24, 2009.**

At this meeting, you will be asked to:

1. Elect the Company's nine nominees as directors;
2. Ratify the appointment of independent auditors for 2009;
3. Approve an amendment to the Articles of Incorporation to increase the number of authorized shares of common stock from 150 million to 250 million shares; and
4. Transact any other business as may properly come before the meeting or any adjournments or postponements thereof.

The attached Notice of Annual Meeting and Proxy Statement describe the business to be transacted at the meeting. Your vote is important. Please review these materials and vote your shares.

We hope you and your guest will be able to attend the meeting. Registration and refreshments will be available starting at 9:00 a.m.

Sincerely,

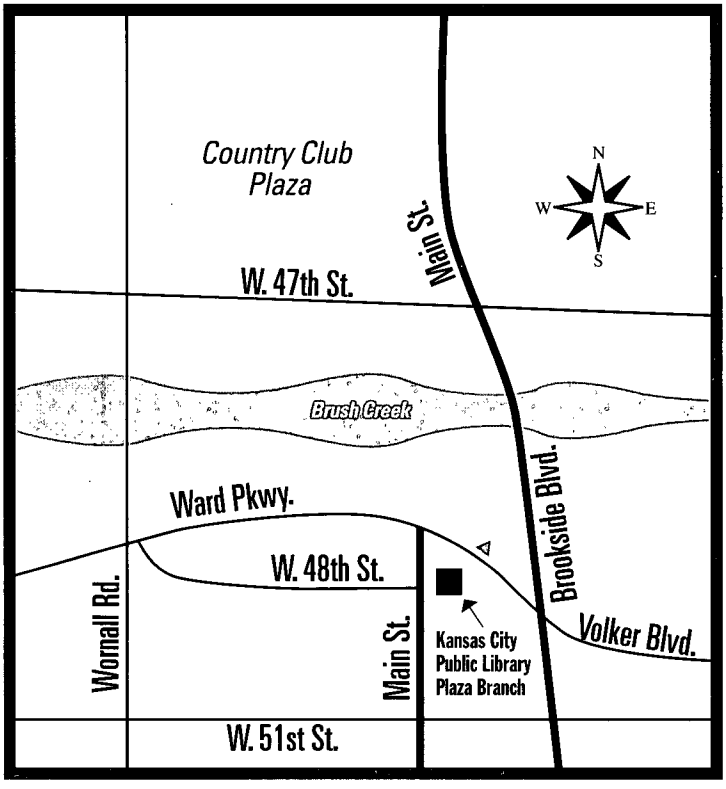
Michael J. Chesser
Chairman of the Board

Important Notice Regarding the Availability of Proxy Materials for the Shareholder Meeting to Be Held on May 5, 2009.

This proxy statement and our 2008 Annual Report are available at *http://materials.proxyvote.com/391164*

GREAT PLAINS® ENERGY

Kansas City Public Library
Plaza Branch
4801 Main Street
Kansas City, MO 64112



△ *Ward Parkway is one-way eastbound from Main St. to Brookside Blvd.*

The Plaza Branch of the Library is located just south of the Country Club Plaza near the intersection of Main and 48th streets. Complimentary parking is available in the parking garage, located off Main St.

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Proxy Statement

GREAT PLAINS ENERGY INCORPORATED

1201 Walnut Street
Kansas City, Missouri 64106

NOTICE OF ANNUAL MEETING OF SHAREHOLDERS

Date: Tuesday, May 5, 2009
Time: 10:00 a.m. (Central Daylight Time)
Place: Kansas City Public Library Plaza Branch
Truman Forum Auditorium
4801 Main Street
Kansas City, Missouri 64112

PROXY STATEMENT

This proxy statement and accompanying proxy card are being mailed, beginning March 25, 2009, to owners of our common stock for the solicitation of proxies by our Board of Directors ("Board") for the 2009 Annual Meeting of Shareholders ("Annual Meeting"). The Board encourages you to read this document carefully and take this opportunity to vote on the matters to be decided at the Annual Meeting.

In this proxy statement, we refer to Great Plains Energy Incorporated as "we," "us," "Company," or "Great Plains Energy," unless the context clearly indicates otherwise.

Important Notice Regarding the Availability of Proxy Materials for the Shareholder Meeting to Be Held on May 5, 2009.

This proxy statement and our 2008 Annual Report are available at *http://materials.proxyvote.com/391164*

ABOUT THE MEETING

Why did you provide me this proxy statement?

We provided you this proxy statement because you are a holder of our common stock and our Board of Directors is soliciting your proxy to vote at the Annual Meeting. As permitted by Securities and Exchange Commission ("SEC") rules, we have mailed a notice regarding the availability of proxy materials (the "Notice") and elected to provide access to this proxy statement and our 2008 annual report to shareholders to our beneficial shareholders and certain of our registered shareholders electronically via the internet. If you received a Notice by mail, you will not receive a printed copy of the proxy materials in the mail, unless you request a printed copy. The Notice explains how to access and review the proxy statement and 2008 annual report to shareholders, and how to vote over the internet. If you received a Notice and would like to receive a printed copy of our proxy materials, you should follow the instructions for requesting such materials included in the Notice. In the future, we may elect to expand electronic delivery and provide all shareholders a Notice rather than incurring the expense of printing and delivering copies of the materials to everyone.

For information on how to receive electronic delivery of annual shareholder reports, proxy statements and proxy cards, please see "Can I elect electronic delivery of annual shareholder reports, proxy statements and proxy cards?" below.

What will be voted on?

At the Annual Meeting, you will be voting on:

- The election of nine directors to our Board;
- The ratification of the appointment of Deloitte & Touche LLP ("Deloitte & Touche") to be our independent registered public accounting firm in 2009; and
- An amendment to our Articles of Incorporation to increase the number of authorized shares of common stock from 150 million to 250 million.

How do you recommend that I vote on these matters?

The Board of Directors recommends that you vote **FOR** each of the people nominated to be directors, **FOR** the ratification of the appointment of Deloitte & Touche, and **FOR** the amendment to our Articles of Incorporation.

Who is entitled to vote on these matters?

You are entitled to vote if you owned our common stock as of the close of business on February 24, 2009 (also referred to as the Record Date). On that day, approximately 119,243,329 shares of our common stock were outstanding and eligible to be voted. Shares of stock held by the Company in its treasury account are not considered to be outstanding, and will not be voted or considered present at the Annual Meeting. At the Annual Meeting, you are entitled to one vote for each share of common stock owned by you at the close of business on the Record Date.

I was an Aquila shareholder, and haven't delivered my Aquila stock certificates for exchange. Am I entitled to vote?

Yes. You are entitled to vote the number of whole shares of Great Plains Energy stock that you have the right to receive in the exchange.

Is cumulative voting allowed?

Cumulative voting is allowed with respect to the election of our directors. This means that you have a total vote equal to the number of shares you own, multiplied by the number of directors to be elected. Your votes for directors may be divided equally among all of the director nominees, or you may vote for one or more of the nominees in equal or unequal amounts. You may also withhold your votes for one or more of the nominees. If you withhold your votes, these withheld votes will be distributed equally among the remaining director nominees.

How many votes are needed to elect directors?

The nine director nominees receiving the highest number of **FOR** votes will be elected. This is called "plurality voting." Withholding authority to vote for some or all of the director nominees, or not returning your proxy card, will have no effect on the election of directors.

How many votes are needed to ratify the appointment of Deloitte & Touche?

Ratification requires the affirmative vote of the majority of shares present in person or by proxy at the Annual Meeting and entitled to vote. Your broker is entitled to vote your shares on this matter if no instructions are received from you. Abstentions will have the effect of negative votes. Shareholder ratification of the appointment is not required, but your views are important to the Audit Committee and the Board. If shareholders do not ratify the appointment, our Audit Committee will reconsider the appointment.

How many votes are needed to approve the amendment to the Articles of Incorporation?

Missouri law requires the amendment to be approved by the affirmative vote of the majority of the outstanding shares of our common stock. Your broker is entitled to vote your shares on this matter if no instructions are received from you. Abstentions will have the effect of negative votes.

How can I submit a proposal to be included in next year's proxy statement?

To be considered for inclusion in our proxy statement for the 2010 annual meeting, the Company must receive notice on or before November 25, 2009. All proposals must comply with the SEC rules regarding eligibility and type of shareholder proposal. Shareholder proposals should be addressed to: Great Plains Energy, P.O. Box 418679, Kansas City, MO 64141-9679, Attention: Corporate Secretary.

Can I bring up matters at the Annual Meeting or other shareholder meeting, other than through the proxy statement?

If you intend to bring up a matter at a shareholder meeting, other than by submitting a proposal for inclusion in our proxy statement for that meeting, our By-laws require you to give us notice at least 60 days, but no more than 90 days, prior to the date of the shareholder meeting. If we give shareholders less than 70 days notice of a shareholder meeting date, the shareholder's notice must be received by the Corporate Secretary no later than the close of business on the tenth (10th) day following the earlier of the date of the mailing of the notice of the meeting or the date on which public disclosure of the meeting date was made. The notice must contain the information required by our By-laws.

May I ask questions at the Annual Meeting?

Yes. We expect that all of our directors, senior management, and representatives of Deloitte & Touche will be present at the Annual Meeting. We will answer your questions of general interest at the

end of the Annual Meeting. We may impose certain procedural requirements, such as limiting repetitive or follow-up questions, so that more shareholders will have an opportunity to ask questions.

How can I propose someone to be a nominee for election to the Board?

The Governance Committee of the Board will consider candidates for director suggested by shareholders, using the process described in the section titled "Director Nominating Process" on page 8.

Our By-laws require shareholders wishing to make a director nomination to give notice not less than 60 days, nor more than 90 days prior to the date of the shareholder meeting. If we give shareholders less than 70 days notice of a shareholder meeting date, your notice must be received by the Corporate Secretary no later than the close of business on the tenth (10th) day following the earlier of the date of mailing of the notice of the meeting or the date on which public disclosure of the meeting date was made. Your notice must comply with the information requirements in our By-laws relating to shareholder nominations.

Who is allowed to attend the Annual Meeting?

If you own our shares, you and a guest are welcome to attend our Annual Meeting. You will need to register when you arrive at the meeting. We may also verify your name against our shareholder list. If you own shares in a brokerage account in the name of your broker or bank ("street name"), you should bring your most recent brokerage account statement or other evidence of your share ownership. If we cannot verify that you own our shares, it is possible that you may not be admitted to the meeting.

ABOUT PROXIES

How can I vote at the Annual Meeting?

You can vote your shares either by casting a ballot during the Annual Meeting, or by proxy.

Is Great Plains Energy soliciting proxies for the Annual Meeting?

Yes, our Board is soliciting proxies. We will pay the costs of this solicitation. In addition to the use of the mails, proxies may be solicited in person, by telephone, facsimile, e-mail or other electronic means by our directors, officers, and employees without additional compensation.

Morrow & Co., Inc., 470 West Avenue, Stamford, CT 06902, has been retained by us to assist in the solicitation, by phone, of votes for a fee of $8,000, plus a charge of $5.00 per holder for telephone solicitations, and reimbursement of out-of-pocket expenses. We will also reimburse brokers, nominees, and fiduciaries for their costs in sending proxy materials to holders of our shares.

How do I vote by proxy before the Annual Meeting?

We have furnished registered shareholders holding more than 500 shares the proxy materials, including the proxy card. These shareholders may also view the proxy materials online at the *www.proxyvote.com* website. They may vote their shares by mail, telephone or internet. To vote by mail, simply mark, sign and date the proxy card and return it in the postage-paid envelope provided. To vote by telephone or internet, 24 hours a day, 7 days a week, refer to your proxy card for voting instructions.

We have mailed a Notice regarding the availability of proxy materials to our other shareholders. These shareholders may choose to view the proxy materials online at the *www.proxyvote.com* website, or receive a paper or e-mail copy. There is no charge for requesting a copy. These shareholders may vote

their shares by internet through the *www.proxyvote.com* website, or by phone after accessing this website, or by mail if they request a paper copy of the proxy materials.

In addition, this Proxy Statement and our 2008 Annual Report are publicly available at *http://materials.proxyvote.com/391164.*

If your shares are registered in the name of your broker or other nominee, you should vote your shares using the method directed by that broker or other nominee. A large number of banks and brokerage firms are participating in the Broadridge Financial Solutions, Inc. online program. This program provides eligible street name shareholders the opportunity to vote via the internet or by telephone. Voting forms will provide instructions for shareholders whose banks or brokerage firms are participating in Broadridge's program.

Properly executed proxies received by the Corporate Secretary before the close of voting at the Annual Meeting will be voted according to the directions provided. If a proxy is returned without shareholder directions, the shares will be voted as recommended by the Board.

What shares are included on the proxy card?

The proxy card represents all the shares registered to you, including all shares held in your Great Plains Energy Dividend Reinvestment and Direct Stock Purchase Plan ("DRIP"), Great Plains Energy 401(k) Plan and KCP&L Greater Missouri Operations Company (formerly Aquila) Retirement Investment Plan accounts as of the close of business on February 24, 2009.

Can I change my mind after I submit a proxy?

You may revoke your proxy at any time before the close of voting by:

- written notice to the Corporate Secretary;
- submission of a proxy bearing a later date; or
- casting a ballot at the Annual Meeting.

If your shares are held in street name, you must contact your broker or nominee to revoke your proxy. If you would like to vote in person, and your shares are held in street name, you should contact your broker or nominee to obtain a broker's proxy card and bring it, together with proper identification and your account statement or other evidence of your share ownership, with you to the Annual Meeting.

I have Company shares registered in my name, and also have shares in a brokerage account. How do I vote these shares?

Any shares that you own in street name are not included in the total number of shares that are listed on your proxy card. Your bank or broker will send you directions on how to vote those shares.

Will my shares held in street name be voted if I don't provide a proxy?

These shares might be voted even if you do not provide voting instructions to the broker. The current New York Stock Exchange ("NYSE") rules allow brokers to vote shares on certain "routine" matters for which their customers do not provide voting instructions. The election of our directors, the ratification of the appointment of Deloitte & Touche and the proposed amendment to our Articles of Incorporation are considered "routine" matters, assuming that no contest arises on these matters.

Is my vote confidential?

We have a policy of voting confidentiality. Your vote will not be disclosed to the Board or our management, except as may be required by law and in other limited circumstances.

ABOUT HOUSEHOLDING

Are you "householding" for your shareholders with the same address?

Yes. Shareholders that share the same last name and household mailing address with multiple accounts will receive a single copy of shareholder documents (annual report, proxy statement, prospectus or other information statement) unless we are instructed otherwise. Each registered shareholder will continue to receive a separate proxy card. Any shareholder who would like to receive separate shareholder documents may call or write us at the address below, and we will promptly deliver them. If you received multiple copies of the shareholder documents and would like to receive combined mailings in the future, please call or write us at the address below. Shareholders who hold their shares in street name should contact their bank or broker regarding combined mailings.

Great Plains Energy Incorporated
Shareholder Relations
P.O. Box 418679
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ELECTION OF DIRECTORS
Item 1 on the Proxy Card

The nine nominees presented have been recommended to the independent directors of the Board by the Governance Committee to serve as directors until the next Annual Meeting and until their successors are elected and qualified. Mr. Mark A. Ernst, who was elected a director at our last Annual Meeting, resigned in January 2009 due to accepting a position as Deputy Commissioner of the Internal Revenue Service. Mr. Luis A. Jimenez, who was also elected a director at our last Annual Meeting, has notified the Board that he will not stand for re-election. No director nominee for either of these two positions is being proposed at this meeting. All of the other directors elected at the 2008 Annual Meeting, with the addition of Gary D. Forsee, who was appointed to the Board on December 2, 2008, are listed below as nominees. Each nominee has consented to stand for election, and the Board does not anticipate any nominee will be unavailable to serve. In the event that one or more of the director nominees should become unavailable to serve at the time of the Annual Meeting, shares represented by proxy may be voted for the election of a nominee to be designated by the Board. Proxies cannot be voted for more than nine nominees.

Nominees for Directors

The following persons are nominees for election to our Board:

David L. Bodde	James A. Mitchell
Michael J. Chesser	William C. Nelson
William H. Downey	Linda H. Talbott
Randall C. Ferguson, Jr.	Robert H. West
Gary D. Forsee	

The Board of Directors recommends a vote FOR each of the nine listed nominees.

Director Nominee Information

David L. Bodde Director since 1994

Dr. Bodde, 66, is the Senior Fellow and Professor, Arthur M. Spiro Institute for Entrepreneurial Leadership at Clemson University (since 2004). He previously held the Charles N. Kimball Chair in Technology and Innovation (1996-2004) at the University of Missouri-Kansas City. He also serves on the boards of The Commerce Funds and our two public utility subsidiaries, Kansas City Power & Light Company (KCP&L) and KCP&L Greater Missouri Operations Company (GMO). Dr. Bodde served as a member of the Executive, Audit, Compensation and Development, and Governance Committees during 2008.

Michael J. Chesser Director since 2003

Mr. Chesser, 60, is Chairman of the Board and Chief Executive Officer of Great Plains Energy (since October 2003), Chairman of the Board (since October 2003) and Chief Executive Officer (since August 2008) of KCP&L, and Chairman of the Board and Chief Executive Officer (since August 2008) of GMO. Mr. Chesser served as a member of the Executive Committee in 2008.

William H. Downey Director since 2003

Mr. Downey, 64, is President and Chief Operating Officer of Great Plains Energy (since October 2003), President (since October 2003) and Chief Operating Officer (since August 2008) of KCP&L, and President and Chief Operating Officer (since August 2008) of GMO. He served as Chief Executive Officer of KCP&L (2003-2008). Mr. Downey also serves on the boards of Enterprise Financial Services Corp., KCP&L, and GMO.

Randall C. Ferguson, Jr. Director since 2002

Mr. Ferguson, 57, was the Senior Partner for Business Development for Tshibanda & Associates, LLC (2005-2007), a consulting and project management services firm committed to assisting clients to improve operations and achieve long-lasting, measurable results. He previously served as Senior Vice President Business Growth & Member Connections with the Greater Kansas City Chamber of Commerce (2003-2005) and is the retired Senior Location Executive (1998-2003) for the IBM Kansas City Region. Mr. Ferguson served on the Audit and Governance Committees during 2008. Mr. Ferguson is also a director of KCP&L and GMO.

Gary D. Forsee Director since 2008

Mr. Forsee, 58, is President of the four-campus University of Missouri System (since February 2008), the state's premier public institution of higher learning. He previously served as Chairman of the Board (2006-2007) and Chief Executive Officer (2005-2007) of Sprint Nextel Corporation, and Chairman of the Board and Chief Executive Officer (2003-2005) of Sprint Corporation. He also serves on the Board of Ingersoll-Rand Company Limited. Mr. Forsee serves as a member of the Audit and Compensation and Development Committees.

James A. Mitchell Director since 2002

Mr. Mitchell, 67, is the Executive Fellow-Leadership, Center for Ethical Business Cultures (since 1999), a not-for-profit organization assisting business leaders in creating ethical and profitable cultures. He also serves on the Board of Capella Education Company. Mr. Mitchell served on the Compensation and Development and Governance Committees during 2008. Mr. Mitchell is also a director of KCP&L and GMO.

William C. Nelson Director since 2000

Mr. Nelson, 71, is Chairman (since 2001) of George K. Baum Asset Management, a provider of investment management services to individuals, foundations, and institutions. He also serves on the Board of DST Systems. Mr. Nelson served on the Executive, Audit, and Compensation and Development Committees during 2008. Mr. Nelson is also a director of KCP&L and GMO.

Linda H. Talbott Director since 1983

Dr. Talbott, 68, is President and CEO of Talbott & Associates (since 1975), consultants in strategic planning, philanthropic management and development to foundations, corporations, and nonprofit organizations. She is also Chairman of the Center for Philanthropic Leadership. Dr. Talbott served as the Advising Director for Corporate Social Responsibility and on the Governance and Compensation and Development Committees during 2008. Dr. Talbott is also a director of KCP&L and GMO.

Robert H. West Director since 1980

Mr. West, 70, retired in July 1999 as Chairman of the Board of Butler Manufacturing Company, a supplier of non-residential building systems, specialty components and construction services. He also serves on the boards of Burlington Northern Santa Fe Corporation and Commerce Bancshares, Inc. Mr. West served as the Lead Independent Director of the Board and as a member of the Audit, Executive, Compensation and Development, and Governance Committees during 2008.

Director Nominating Process

The Governance Committee identifies and recommends director nominees to the independent directors of the Board. At its discretion, the Governance Committee may pay a fee to third party consultants and experts to help identify and evaluate potential nominees.

The Governance Committee takes into account a number of factors when considering director nominees, as described in our Corporate Governance Guidelines. Director nominees are selected based on their practical wisdom, mature judgment, and the diversity of their backgrounds and business experience. Nominees should possess the highest levels of personal and professional ethics, integrity,

and values and be committed to representing the interests of shareholders. The Governance Committee may also consider in its assessment the Board's diversity in its broadest sense, reflecting geography, age, gender, and ethnicity, as well as other appropriate factors.

In December 2008, our By-laws were amended to expand the information that must be provided by a shareholder who submits a director nomination. The required information now includes, among other things, (i) certain details about all ownership interests in the Company by the shareholder, the beneficial owner of the shares (if different) on whose behalf the nomination is made, and any affiliate, associate or other persons acting in concert (collectively referred to as the "Proposing Person"), including any hedging, derivative, short or other economic interests and any rights to vote the Company's shares, (ii) all material relationships between and among the Proposing Person and each proposed director nominee, and (iii) all arrangements or agreements between the Proposing Person in connection with the nomination and/or proposal. The By-laws, as amended, also require the proposed nominee to include with the notice a questionnaire providing information about the proposed nominee's background and qualifications and the background of any other person or entity on whose behalf the nomination is being made. The proposed nominee must also provide a written representation and agreement regarding voting commitments, compensation, reimbursement or indemnification agreements, and compliance with corporate governance and other policies and guidelines of the Company. The By-laws also require updating and supplementing the information, as necessary, so that the information is true and correct as of the record date for the meeting, and as of the date of the shareholders meeting or any adjournment or postponement of that meeting.

RATIFICATION OF APPOINTMENT OF INDEPENDENT AUDITORS
Item 2 on the Proxy Card

Deloitte & Touche has acted as our independent registered public accounting firm since 2002, and has been appointed by the Audit Committee to audit our financial statements for 2009, subject to ratification by the shareholders of the Company.

Representatives from Deloitte & Touche are expected to be present at the Annual Meeting, with the opportunity to make statements if they wish to do so, and are expected to be available to respond to appropriate questions.

The affirmative vote of the holders of a majority of the shares of our common stock present and entitled to vote at the meeting is required for ratification of this appointment. If the appointment of Deloitte & Touche is not ratified, the selection of the independent registered public accounting firm will be reconsidered by the Audit Committee.

Audit Committee Pre-Approval of Audit and Permissible Non-Audit Services of Independent Registered Public Accounting Firms

The Audit Committee pre-approves all audit and permissible non-audit services provided by the independent registered public accounting firms to the Company and its subsidiaries. These services may include audit services, audit-related services, tax services and other services. The Audit Committee has adopted for the Company and its subsidiaries policies and procedures for the pre-approval of services provided by the independent registered public accounting firms. 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. 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. The Audit Committee, as well, may specifically approve audit and permissible non-audit services on a case-by-case basis. Pre-approval is generally provided for up to one year, unless the Audit Committee specifically provides for a different period. The Audit Committee receives reports at each regular meeting regarding the

pre-approved services performed by the independent registered public accounting firms. The Chairman of the Audit Committee may between meetings pre-approve audit and non-audit services provided by the independent registered public accounting firms, and report such pre-approval at the next Audit Committee meeting.

Fees paid to Deloitte & Touche

The following table sets forth the aggregate fees billed by Deloitte & Touche for audit services rendered in connection with the consolidated financial statements and reports for 2008 and 2007, and for other services rendered during 2008 and 2007 on behalf of the Company and its subsidiaries (all of which were pre-approved by the Audit Committee), as well as all out-of-pocket costs incurred in connection with these services:

Fee Category	2008	2007
Audit Fees	$2,828,707	$2,294,695
Audit-Related Fees	126,772	100,213
Tax Fees	47,871	43,349
All Other Fees	5,400	4,500
Total Fees:	$3,008,750	$2,442,757

Audit Fees: Consist 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 in connection with statutory and regulatory filings or engagements; audit of and reports on 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 SEC, including comfort letters, consents and assistance with and review of documents filed with the SEC; and accounting research in support of the audit. The increase in audit fees in 2008 was driven primarily by the sale of Strategic Energy and the acquisition of Aquila in 2008.

Audit-Related Fees: Consist of fees billed to the Company for benefit plan audits and for assurance and related services that are reasonably related to the performance of the audit or review of consolidated financial statements of the Company and its subsidiaries, and are not reported under "Audit Fees." These services include consultation concerning financial accounting and reporting standards and, in 2008 and 2007, the acquisition of Aquila.

Tax Fees: Consist of fees billed to the Company for benefit plan tax services and 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: Consist of fees for all other services other than those reported above. Those services in 2008 and 2007 included accounting research tool subscriptions.

The Board of Directors recommends a vote FOR ratification.

AUDIT COMMITTEE REPORT

The Audit Committee is currently comprised of five independent directors. In connection with its function to oversee and monitor the financial reporting process of Great Plains Energy, the Audit Committee's activities in 2008 included the following:

- reviewed and discussed the audited financial statements and the report on internal control over financial reporting with management and Deloitte & Touche;
- discussed with Deloitte & Touche the matters required to be discussed by SEC regulations and by Statement on Auditing Standards No. 61, as amended, as adopted in Rule 3200T of the Public Company Accounting Oversight Board (the "PCAOB"); and
- received the written disclosures and the letter from Deloitte & Touche required by applicable requirements of the PCAOB regarding Deloitte & Touche's communications with the Audit Committee concerning independence, and discussed with Deloitte & Touche its independence from management and the Company and its subsidiaries.

Based on the reviews and discussions referred to above, the Audit Committee recommended to the Board of Directors that the audited financial statements be included in the Company's annual report on Form 10-K for the fiscal year ended December 31, 2008 for filing with the SEC.

Audit Committee

Robert H. West, Chair
David L. Bodde
Randall C. Ferguson, Jr.
Gary D. Forsee
William C. Nelson

APPROVAL OF AMENDMENT TO ARTICLES OF INCORPORATION
Item 3 on the Proxy Card

Description of the Proposed Amendment

The Board has adopted, subject to shareholder approval, a resolution to amend our Articles of Incorporation in order to increase the number of authorized shares of common stock from 150 million to 250 million shares. The proposed amendment does not change the number of Cumulative Preferred Stock, Cumulative No Par Preferred Stock or Preference Stock that the Company is authorized to issue.

The text of the first paragraph of Article Three of our Articles of Incorporation, as it is proposed to be amended, reads as follows:

> The amount of authorized capital stock of the Company is Two Hundred Sixty Two Million Nine Hundred Sixty Two Thousand (262,962,000) shares divided into classes as follows:
>
> > Three Hundred Ninety Thousand (390,000) shares of Cumulative Preferred Stock, of the par value of One Hundred Dollars ($100) each.
> >
> > One Million Five Hundred Seventy Two Thousand (1,572,000) shares of Cumulative No Par Preferred Stock without par value.
> >
> > Eleven Million (11,000,000) shares of Preference Stock without par value.
> >
> > Two Hundred Fifty Million (250,000,000) shares of Common Stock without par value.

The Board has directed that this amendment be submitted to our common shareholders for their consideration and approval.

Reasons for the Proposed Amendment

The Company has not increased the number of authorized shares of common stock since it became a publicly traded company in October 2001. At that time, the Company assumed the capital structure of KCP&L, which had 150 million shares of common stock authorized and approximately 62 million shares of common stock outstanding. As of February 24, 2009, the Company had approximately 119,480,212 shares of common stock issued and outstanding out of the currently authorized 150 million shares and, after taking into account shares reserved for issuance under our 401(k) plans, equity compensation plans and periodic offering program, approximately 16,155,600 shares of common stock were available for issuance. The increase in the number of outstanding shares since 2001 is primarily due to the shares issued to the former Aquila shareholders in exchange for their Aquila shares, and shares sold in public offerings.

The Board believes that it is prudent, especially in the current volatile economic and financial environment, to increase the number of authorized shares of common stock to provide flexibility with respect to matters such as offerings to raise capital to contribute to our public utility subsidiaries in connection with their ongoing construction programs and for their other general corporate purposes, acquisitions of businesses or property, equity compensation plans, possible stock splits or stock dividends, and for other general corporate purposes. The Company's currently announced financing plans project the issuance of about $200 million in equity through 2010, and about $200 million in 2011, to provide capital for our public utility subsidiaries. Given the current state of the capital markets, there can be no assurances that the Company will be successful in issuing equity, the prices at which equity may be issued, or whether any such financing plans would include the issuance of these additional shares of common stock. There are currently no definitive plans, agreements or arrangements in place requiring the utilization of these additional shares for any of the foregoing. Having such additional authorized common shares available for issuance in the future would, however, allow the Board of Directors to issue shares of common stock without the delay and expense associated with seeking shareholder approval at a special shareholders meeting or waiting until the next annual meeting. Elimination of such delays and expense will better enable the Company, among other things, to take advantage of changing market and financial conditions.

Possible Adverse Effects of the Amendment on Common Shareholders

The additional common stock to be authorized by adoption of this amendment would have rights identical to the currently outstanding common stock of the Company. If our shareholders approve the amendment, our Board may cause the issuance of additional shares of common stock without further vote of the shareholders, except as may be required by applicable laws or the rules of the NYSE and any other national securities exchanges on which our common stock is then listed. The proposed amendment will not have any immediate effect on the rights of existing common shareholders. However, to the extent that the additional authorized shares of common stock are issued in the future, they will decrease the existing common shareholders' percentage equity ownership and voting power and, depending on the price at which they are issued, could be dilutive to existing common shareholders. Current holders of our common stock have no preemptive or similar rights, which means that they do not have a prior right to purchase any new issuance of common stock to maintain their proportionate ownership interests. Issuance of additional common stock authorized by this amendment may also reduce the portion of dividends and liquidation proceeds available to the holders of currently outstanding common stock. Although the Board has no present intention of doing so, the additional shares of common stock could be used to make it more difficult to effect a change in control of the Company. Presently, the Board knows of no attempt to obtain control of the Company.

Vote required for Approval

The proposed amendment must be approved by the affirmative vote of a majority of the outstanding common stock shares entitled to vote at the Annual Meeting. If the amendment is approved by the common shareholders, the amendment will become effective upon filing of a certificate of amendment with the Missouri Secretary of State, which the Company anticipates filing promptly following the Annual Meeting, or as soon as practicable thereafter.

The Board of Directors recommends a vote FOR the proposed amendment.

CORPORATE GOVERNANCE

Our business, property and affairs are managed under the direction of our Board, in accordance with Missouri General and Business Corporation Law and our Articles of Incorporation and By-laws. Although directors are not involved in the day-to-day operating details, they are kept informed of our business through written reports and documents regularly provided to them. In addition, directors receive operating, financial and other reports by the Chairman and other officers at Board and Committee meetings.

Board Attendance at Annual Meeting. All directors are expected to attend the 2009 Annual Meeting. All directors (with the exception of Dr. William K. Hall, who did not stand for reelection) were present at the 2008 Annual Meeting.

Meetings of the Board. The Board held ten meetings in 2008. Each of our directors attended at least 80% of the aggregate number of meetings of the Board and committees to which he or she was assigned. Mr. Forsee was appointed to the Board on December 2, 2008, and no Board committee meetings were held between his appointment and the end of 2008. The independent members of the Board annually elect a Lead Independent Director. Mr. West was the Lead Independent Director in 2008, and continues in that role in 2009. Mr. West, as Lead Independent Director, presides over regularly scheduled executive sessions of the non-management members of the Board, among other duties set out in our Corporate Governance Guidelines.

Committees of the Board. The Board's four standing committees are described below. Directors' committee memberships are included in their biographical information beginning on page 7.

Executive Committee—exercises the full power and authority of the Board to the extent permitted by Missouri law. The Committee generally meets when action is necessary between scheduled Board meetings. The Committee's current members are Messrs. Chesser (Chairman), Nelson and West, and Dr. Bodde.

The Committee did not meet in 2008.

Audit Committee—oversees the auditing, accounting and financial reporting of the Company including:

- monitoring the integrity of the Company's financial reporting process and systems of internal controls regarding finance, accounting, legal and regulatory compliance;
- maintaining procedures for the receipt, retention and treatment of complaints regarding accounting, internal accounting control or auditing matters and the confidential, anonymous submission by employees of concerns regarding questionable accounting and auditing matters;
- monitoring the Company's controls regarding fraud prevention, detection and reporting of any fraud, whether or not material, that involves management or other employees who have a significant role in the Company's internal control over financial reporting;

- having direct responsibility for the appointment, compensation, retention, termination, terms of engagement, evaluation and oversight of the work of the Company's independent auditors;
- reviewing and discussing significant audit services department findings and recommendations and management's responses; and
- providing an avenue of communication among the independent auditors, management, audit services department and the Board.

The Committee's current members are Messrs. West (Chairman), Ferguson, Forsee and Nelson, and Dr. Bodde. Mr. Ernst served as Chairman of the Committee through 2008 and until his resignation in January 2009. Dr. Hall also served on the Committee until the 2008 Annual Meeting. All members of the Audit Committee are "independent," as defined for audit committee members by the NYSE listing standards. The Board identified Messrs. Forsee, Nelson, and West as independent "audit committee financial experts" as that term is defined by the SEC pursuant to Section 407 of the Sarbanes-Oxley Act of 2002.

The Committee held eight meetings in 2008.

Compensation and Development Committee—reviews and assists the Board in overseeing compensation and development matters including:

- aligning the interests of directors and executives with the interests of shareholders;
- motivating performance to achieve the Company's business objectives;
- developing existing and emerging executive talent within the Company;
- engaging third-party consultants to assist the Committee in the development and evaluation of compensation programs and compensation recommendations;
- administering Great Plains Energy's incentive plans for senior officers; and
- recommending compensation to be paid to Board members and Company officers.

The Committee's current members are Messrs. Nelson (Chairman), Forsee, Jimenez, Mitchell and Drs. Bodde and Talbott. Mr. Ernst was a member of the Committee through 2008 and until his resignation in January 2009. The Committee held five meetings in 2008.

The processes and procedures for considering and determining executive compensation, including the Committee's authority and role in the process, its delegation of authority to others, and the roles of our executive officers and third-party executive compensation consultants in making the decisions or recommendations, are described in the "Compensation Discussion and Analysis" section below.

Governance Committee—reviews and assists the Board with all corporate governance matters including:

- identifying and recommending nominees qualified to become Board members;
- monitoring the effectiveness of the Company and its subsidiaries in meeting overall objectives and goals of the organization;
- developing, recommending and monitoring a set of appropriate corporate governance principles applicable to Great Plains Energy and its subsidiaries; and
- monitoring the effectiveness of the Company's social responsibility program.

The Committee's current members are Messrs. Jimenez (Chairman), Ferguson, Mitchell, West and Dr. Talbott. Dr. Hall also served on the Committee until the Annual Meeting in 2008. The Committee held four meetings in 2008.

Corporate Governance Guidelines, Committee Charters and Code of Ethical Business Conduct. The Board has adopted written corporate governance guidelines, charters for the Audit, Compensation and Development, and Governance Committees, and a Code of Ethical Business Conduct. These documents are available on the Company's website at *www.greatplainsenergy.com*. These documents are also available in print to any shareholder upon request. Requests should be directed to Corporate Secretary, Great Plains Energy Incorporated, P.O. Box 418679, Kansas City, MO 64141-9679.

DIRECTOR INDEPENDENCE

Our stock is listed on the NYSE, and our Board uses the NYSE director and Board committee independence definitions in determining whether our directors and committee members are independent. In addition, there are SEC independence requirements for the members of our Audit Committee.

The NYSE director independence definitions provide that directors cannot be independent if they do not meet certain objective standards, or if the Board determines that the director has a material relationship with the Company. The Board determined at its February 2009 meeting that the following current directors (who, with the exception of Mr. Jimenez, are also nominees for directors at our Annual Meeting) are "independent" under the NYSE definitions:

David L. Bodde	Luis A. Jimenez	Linda H. Talbott
Randall C. Ferguson, Jr.	James A. Mitchell	Robert H. West
Gary D. Forsee	William C. Nelson	

The Board also determined in 2008 that Dr. Hall (who did not stand for reelection in 2008) and Mr. Ernst (who resigned in January 2009) were independent under the NYSE definitions.

Only these independent directors are members of our Audit, Compensation and Development, and Governance Committees. All members of our Audit Committee also meet the additional NYSE and SEC independence requirements. Messrs. Chesser and Downey are not "independent" under the NYSE definitions, because they are also officers of the Company.

In making its independence determinations, the Board considered all commercial, charitable and other transactions and relationships between the Company and its subsidiaries, on the one hand, and the directors and their immediate family members, on the other hand, that were disclosed in the annual questionnaires that our directors completed in January 2009. None of the identified transactions is a "related party" transaction that is required to be disclosed in this proxy statement. The Board concluded that the transactions and relationships did not impair the independence of the current non-officer directors. The categories or types of these transactions and relationships are identified for each non-officer director in the following table.

Name	Relationships
David L. Bodde	Trustee of a mutual fund family associated with a bank that participates in revolving credit agreements with the Company and provides other financial services to Company.
Randall C. Ferguson, Jr.	Director of charitable, civic and educational organizations to which the Company contributes, pays dues or fees, or has officers serving as directors; director of a service provider to Company employee health and welfare plans; related to an employee of a service provider to Company employee health and welfare plans; related to an employee of a bank that participates in revolving credit agreements with the Company and provides other financial services to the Company; and related to an employee of a supplier to the Company.
Gary D. Forsee	Director of a supplier to the Company; President of the University of Missouri System, to which the Company contributes, makes tuition reimbursements to its employees, and has certain officers and directors serving in trustee or advisory positions; director of charitable or civic organizations to which the Company contributes; and related to an employee of a supplier to the Company.
Luis A. Jimenez	Former officer of a supplier to the Company.
William C. Nelson	Director of a service provider to Company employee health and welfare plans; director, or spouse of a director, of charitable, civic and educational organizations to which the Company contributes, pays dues or fees, or has directors or officers serving as directors or officers; director of a supplier to the Company.
Linda H. Talbott	Advisor to charitable or civic organizations to which the Company contributes, pays dues or fees.
Robert H. West	Director of suppliers to the Company; director of a bank that participates in revolving credit agreements with the Company and provides other financial services to the Company; director of an educational organization to which the Company contributes.

In addition to those matters, the Board considered the fact that our regulated electric utility subsidiaries provide retail electric service to the directors, their immediate family members, and employers who are in our utility subsidiaries' service territories.

RELATED PARTY TRANSACTIONS

The Governance Committee has established written policies and procedures for review and approval of transactions between the Company and related parties. If a related party transaction subject to review directly or indirectly involves a member of the Governance Committee (or an immediate family member of such member), the remaining Governance Committee members will conduct the review. In evaluating a related party transaction involving a director, executive officer, holder of more than 5% of our voting stock, or any member of the immediate family of any of the foregoing persons, the Governance Committee considers, among other factors:

- The benefits to the Company associated with the transaction and whether comparable or alternative goods or services are available to the Company from unrelated parties;
- The nature of the transaction and the costs to be incurred by the Company or payment to be made to the Company;
- The terms of the transaction, including the goods or services provided by or to the related party;
- The significance of the transaction to the Company and to the related party; and
- Whether the related party transaction is in the best interest of the Company.

Each year, each director and officer completes a questionnaire that requires disclosure of any transaction with the Company in which they, or any member of their immediate family, has a direct or indirect material interest. The questionnaire also requires disclosure of relationships that the director or officer, and the members of his or her immediate family, have with other entities. Directors and officers are also required to notify the Corporate Secretary when there are any changes to the previously reported information.

The Company's legal staff is primarily responsible for the development and implementation of procedures and controls to obtain information from the Company's directors and officers relating to related party transactions and relationships and determining, based upon the facts and circumstances, including a review of Company records, whether the Company or a related party has a direct or indirect material interest in a transaction. The Company's legal staff then provides the results of its evaluation to the Governance Committee and Board for their use in determining director independence and related party disclosure obligations. Please see the section titled "Director Independence" on page 15 for a discussion of how director independence is determined.

The Governance Committee's policies provide that certain types of related party transactions are permitted without prior approval of the Governance Committee, even if the aggregate amount involved will exceed $120,000 (although all such transactions are reported annually to the Governance Committee and the Board), including but not limited to:

- where the transaction is one where the rates or charges are determined by competitive bids and the transaction was the lowest bid;
- tariffed retail electric services provided by the Company;
- transactions where the party's interest arises only from his or her position as a director of the other party;
- transactions with another entity at which the party's only relationship is as an employee (other than an executive officer),
- if the aggregate amount involved does not exceed the greater of $1 million or 2% of that entity's consolidated gross revenues;

- any charitable contribution, grant or endowment by the Company to a charitable organization, foundation or university at which a party's only relationship is as an employee (other than an executive officer), director or trustee, if the aggregate amount involved is less than the greater of $1 million or 2% of the organization's total annual charitable receipts;
- transactions involving common or contract carrier services at rates fixed in conformity with law or governmental authority; and
- transactions (other than loans by the Company) available to all employees generally.

To receive Governance Committee approval, related party transactions must have a Company business purpose and be on terms that are fair and reasonable to the Company, or as favorable to the Company as would be available from non-related entities in comparable transactions. The Governance Committee also requires that the transaction meets the same Company standards that apply to comparable transactions with unaffiliated entities.

The following transaction involved a subsidiary of the Company as a party, in which the amount involved exceeded $120,000, and in which a holder of more than 5% of our common stock may have had a material direct or indirect interest.

On February 5, 2009, a Schedule 13G was filed by Barclays Global Investors, NA, and affiliated reporting persons. This was the first Schedule 13G filed by Barclays Global Investors, or any of their affiliates, regarding Great Plains Energy stock. The Schedule 13G stated that the reporting persons collectively held 5.07% of Great Plains Energy common stock as of December 31, 2008. Please see the section titled "Security Ownership of Certain Beneficial Owners, Directors and Officers" on page 20 for additional information.

Following the policies and procedures described above, we determined that in 2001, a subsidiary of GMO (which we acquired in July 2008) entered into a natural gas financial swap agreement with Barclays Bank. This swap agreement expired on December 31, 2008. Pursuant to the terms of the swap agreement, the GMO subsidiary paid Barclays Bank $8,010,870 during the period it was a subsidiary of Great Plains Energy.

The Governance Committee ratified this completed transaction. In making this decision, the Governance Committee considered relevant facts and circumstances, including: the transaction was entered into more than six years before GMO was acquired by the Company in 2008 and the Schedule 13G was filed in 2009; from available evidence, the transaction was entered into on an arms-length basis between the GMO subsidiary and Barclays Bank; GMO did not report this transaction in its proxy statements, indicating that the transaction was not a related party transaction between GMO and Barclays Bank; there was no other transaction between the Company and Barclays Bank or its affiliates in 2008; and no director or officer of the Company reported any relationship with Barclays Bank or its affiliates.

Compensation Committee Interlocks and Insider Participation

None of the members of our Compensation and Development Committee is or was an officer or employee of Great Plains Energy or its subsidiaries. None of our executive officers served as a director or was a member of the compensation committee (or equivalent body) of any entity where a member of our Board or Compensation and Development Committee was also an executive officer.

BOARD POLICY REGARDING COMMUNICATIONS

The Company has a process for communicating with the Board. Communications from interested parties to the non-management members of the Board can be directed to:

Chairman, Governance Committee
Great Plains Energy Incorporated
P.O. Box 418679
Kansas City, MO 64141-9679

Attn: Barbara B. Curry, Corporate Secretary

Communications are forwarded to the Governance Committee to be handled on behalf of the Board.

SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS, DIRECTORS AND OFFICERS

The following tables show, as of February 27, 2009, beneficial ownership of Company common stock by (i) each director, (ii) the named executive officers ("NEOs"), (iii) all directors and executive officers as a group, and (v) each shareholder who the Company knows is a beneficial owner of more than 5% of the outstanding shares of the Company's common stock (based on SEC filings). The total of all shares owned by directors and executive officers represents less than 1% of our outstanding shares. Our management has no knowledge of any person (as defined by the SEC) who owns beneficially more than 5% of our common stock, except as described below. Except as noted below, the Company believes that the persons listed in the tables below have sole voting and investment power with respect to the securities listed.

Security Ownership of Directors and Executive Officers

Name (a)	Beneficially Owned Shares (#) (b)	Vested Stock Options and Options that Vest Within 60 Days (#) (c)	Share Equivalents to be Settled in Stock [1] (#) (d)	Total Share Interest (#) (e)
Named Executive Officers				
Michael J. Chesser	132,299 [2]	—	—	132,299 [2]
William H. Downey	108,408 [3]	45,249	—	153,657 [3]
Terry Bassham	36,582 [4]	—	—	36,582 [4]
Stephen T. Easley	24,889 [5]	—	—	24,890 [5]
Shahid Malik	20,000	—	—	20,000
John R. Marshall	65,271 [6]	—	—	65,271 [6]
Non-Management Directors				
David L. Bodde	15,001 [7]	—	4,455	19,456 [7]
Randall C. Ferguson, Jr.	7,518	—	4,455	11,973
Gary D. Forsee	—	—	2,558	2,558
Luis A. Jimenez	13,478	—	—	13,478
James A. Mitchell	12,948	—	—	12,948
William C. Nelson	13,968 [8]	—	—	13,968 [8]
Linda H. Talbott	14,165 [9]	—	4,455	18,620 [9]
Robert H. West	13,143 [10]	—	4,455	17,598 [10]
All Great Plains Energy Directors and Executive Officers as a Group (19 persons)				633,786

(1) The shares listed are director deferred share units through our Long-Term Incentive Plan which will be settled in stock on a 1-for-1 basis upon the first January 31st following the last day of service on the Board.
(2) The amount shown includes 67,141 restricted stock shares and 1,407 shares held in the 401(k) plan.
(3) The amount shown includes 38,403 restricted stock shares and 2,260 shares held in the 401(k) plan.
(4) The amount shown includes 19,852 restricted stock shares.
(5) The amount shown includes 2,002 shares held in the 401(k) plan.
(6) The amount shown includes 20,245 restricted stock shares and 1,743 shares held in the 401(k) plan.
(7) The amount shown includes 13,510 shares held in joint tenancy with Dr. Bodde's spouse, and 1,000 shares held in trust accounts for Dr. Bodde's mother in which Dr. Bodde is trustee. Dr. Bodde disclaims beneficial ownership of the 1,000 shares in such trust accounts.

(8) The amount shown includes 62 shares reported and held by Mr. Nelson's spouse. Mr. Nelson disclaims beneficial ownership of such shares.
(9) The amount shown includes 2,400 shares held in joint tenancy with Dr. Talbott's spouse.
(10) The amount shown includes 492 shares held in joint tenancy with Mr. West's wife, and 1,000 shares reported and held by Mr. West's spouse. Mr. West disclaims beneficial ownership of the 1,000 shares reported and held by his spouse.

Beneficial Ownership of 5% or More

Name and Address of Beneficial Owner	Beneficial Ownership of Common Stock (Based on Schedule 13G Filing)	Percentage of Common Shares Outstanding
Barclays Global Investors, NA. 400 Howard Street San Francisco, CA 94105	6,029,834	5.06%

The information in the preceding table and in this paragraph is taken entirely from the Schedule 13G filed by Barclays Global Investors, NA, and affiliated reporting persons on February 5, 2009. The Schedule 13G states that the reporting persons collectively hold 6,029,834 shares as to which such persons have sole power to dispose or to direct the disposition of such shares, and 4,616,325 shares as to which such persons have sole power to vote or to direct the vote of such shares. The percentage is based on approximately 119,243,329 shares of the Company's common stock outstanding as of February 27, 2009.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934, as amended, requires our directors, executive officers and persons who own more than 10% of our common stock to file reports of holdings and transactions in our common stock with the SEC. Based upon our records, we believe that all required reports for 2008 have been timely filed, except for the matters discussed in the following paragraph.

The number of shares surrendered by Mr. Malik in connection with the vesting of restricted stock and performance share awards in June 2008 was inadvertently under-reported. The number of Company shares acquired by Mr. Michael Deggendorf, an executive officer of the Company, in exchange for Aquila shares he acquired as an Aquila officer prior to 2003, was not timely reported. Reports filed by Dr. Bodde and Mr. Nelson inadvertently included indirectly held shares in the amounts shown as directly held. All of these errors have been corrected.

DIRECTOR COMPENSATION

We compensate our non-employee directors as summarized below. Messers. Chesser and Downey are officers of the Company, and do not receive compensation for their service on the Board. We paid non-employee directors an annual retainer of $85,000 in 2008. Of this amount, $35,000 was in cash, and $50,000 was in common stock (valued on the grant date and rounded to the next highest whole share) through our Long-Term Incentive Plan (the "LTIP"). Our Lead Independent Director received an additional annual retainer of $20,000, and the chairs of the Board's Audit, Compensation and Development, and Governance Committees received an additional annual retainer of $10,000, $5,000 and $5,000, respectively. Attendance fees of $1,000 for each Board meeting and $1,000 for each committee and other meeting attended were also paid in 2008. Directors may defer the receipt of all or part of the cash retainers and meeting fees through our non-qualified deferred compensation plan, and may also defer the receipt of all or part of the common stock through Director Deferred Share Units ("DSUs") under the LTIP. Directors must make their deferral elections prior to the year in which the common stock would be paid. The number of DSUs granted is equal to the number of shares of common stock that otherwise would have been payable to the director. As of the date any dividend is

paid to common stock shareholders, each DSU account is credited with additional DSUs equal to the number of shares of common stock that could have been purchased (at the closing price of our common stock on that date) with the amount which would have been paid as dividends on the number of shares equal to the number of DSUs held on that date. DSUs will be converted into an equal amount of shares of common stock on the January 31st next following the date the director's service on the Board terminates. The number of whole shares will be distributed to the director, with any fractional share paid in cash (using the closing price of our common stock as of the preceding business day).

We offer life and medical insurance coverage for the current non-employee directors serving as of January 1, 2008, and their families. We do not offer this coverage to non-employee directors who were first elected after 2007. The aggregate premium paid by us for this coverage in 2008 was $45,621. We pay or reimburse directors for travel, lodging and related expenses they incur in attending Board and committee meetings. We paid in certain years prior to 2008, and we may pay in future years, the expenses incurred by directors' spouses in accompanying the directors to one Board meeting per year. We did not pay any such expenses in 2008. We also match on a two-for-one basis up to $5,000 per year (which would result in up to a $10,000 Company match) of charitable donations made by a director to 501(c)(3) organizations that meet our strategic giving priorities and are located in our generation and service communities.

The following table outlines all compensation paid to our non-employee directors in 2008. We have omitted the columns titled "Option awards" and "Non-equity incentive plan compensation" because our non-employee directors did not receive any in 2008.

DIRECTOR COMPENSATION

Name (a)	Fees Earned or Paid in Cash (1) ($) (b)	Stock Awards (2) ($) (c)	Change in Pension Value and Nonqualified Deferred Compensation Earnings (3) ($) (f)	All other Compensation (4) ($) (g)	Total ($) (h)
Dr. Bodde	58,000	50,006	33,553	3,108	144,667
Mr. Ernst	69,000	50,006	13,867	10,101	142,974
Mr. Ferguson	57,000	50,006	—	40,987	147,993
Mr. Forsee (5)	—	—	—	—	—
Dr. Hall (6)	21,231	50,006	—	101	71,338
Mr. Jimenez	58,000	50,006	468	101	108,575
Mr. Mitchell	53,000	50,006	—	101	103,107
Mr. Nelson	64,000	50,006	—	10,101	124,107
Dr. Talbott	54,000	50,006	3,296	21,465	128,767
Mr. West	78,000	50,006	26,559	19,525	174,090

(1) The amounts shown include retainers of $35,000, attendance fees of $1,000 for each Board and Committee meeting attended, and additional retainers for Mr. West ($20,000), as lead director, and Messrs. Ernst ($10,000), Nelson ($5,000) and Jimenez ($5,000) as committee chairs.

(2) The amounts shown in this column are the compensation expense as recognized for financial statement reporting purposes with respect to the fiscal year in accordance with the Financial Accounting Standards Board Statement of Financial Accounting Standard No. 123 (revised 2004), "Share-Based Payment" ("FAS 123R") for Director Shares and DSUs. Compensation expense is calculated by multiplying the number of Director Shares and DSUs by the $28.30 closing price of Company stock on the February 5, 2008, grant date, and thus the compensation expense recognized is the same as the fair market value. The value of shares credited on DSUs on account of dividends paid on common stock is not included in the FAS 123R calculation, and instead is reflected in the "All Other Compensation" column. The DSUs are not subject to any service-based vesting conditions. As of December 31, 2008, Dr. Bodde, Messrs. Ferguson and West, and Dr. Talbott each held an aggregate of 1,897 DSUs (including shares credited on account of dividends paid on common stock).

(3) The amounts shown represent the above-market earnings during 2008 on nonqualified deferred compensation.
(4) The amounts shown consist of, as applicable for each director, matched charitable contributions, premiums for life insurance and health insurance, and the value of shares credited on Director Deferred Share Units on account of dividends paid on common stock. The matched charitable contributions reported in this column are: Mr. Ernst, $10,000; Mr. Ferguson, $10,000; Mr. Nelson, $10,000; Dr. Talbott, $9,940; and Mr. West, $8,000. As permitted by SEC rules, we excluded from the table perquisites and personal benefits for any director where the total value was less than $10,000. No item that was not a perquisite or personal benefit exceeded $10,000, except for Mr. Ferguson. The Company paid $27,980 during 2008 for life and health insurance for Mr. Ferguson.
(5) Mr. Forsee was elected in December 2008, and did not receive any compensation during the year.
(6) Dr. Hall's term expired on May 6, 2008.

COMPENSATION DISCUSSION AND ANALYSIS

This section provides information and a comprehensive analysis of the compensation awarded to, earned by, or paid to our NEOs:

- Michael J. Chesser, *Chairman of the Board and Chief Executive Officer of Great Plains Energy, Kansas City Power & Light Company (KCP&L) and KCP&L Greater Missouri Operations Company (GMO);*
- William H. Downey, *President and Chief Operating Officer of Great Plains Energy, KCP&L and GMO;*
- Terry Bassham, *Executive Vice President—Finance and Strategic Development and Chief Financial Officer of Great Plains Energy, KCP&L and GMO;*
- John R. Marshall, *Executive Vice President—Utility Operations of KCP&L and GMO;*
- Stephen T. Easley, *former Senior Vice President—Supply, KCP&L and GMO; and*
- Shahid Malik, *former Executive Vice President of Great Plains Energy and former President and Chief Executive Officer of Strategic Energy.*

Mr. Easley resigned his positions effective as of January 2, 2009. Mr. Malik's employment was terminated in conjunction with the sale of Strategic Energy, L.L.C. on June 2, 2008.

Great Plains Energy currently has a single core utility business comprised of two subsidiaries: KCP&L, an integrated, regulated electric utility that provides electricity to customers primarily in the states of Missouri and Kansas; and GMO, an integrated, regulated electric utility that provides electricity to customers in the state of Missouri. These utilities are referred to collectively as "KCP&L." Until mid-December 2008, a small services organization provided common support functions across both subsidiaries. Employees in that organization were subsequently transferred to KCP&L. Given the significant differences in the scope and nature of responsibilities amongst the NEOs, as well as differences in market levels of compensation, there are generally significant differences in compensation.

Governance of the Company's Compensation Program

The Committee currently is made up of seven non-employee directors, each of whom is independent under the applicable standards of the NYSE. The Lead Director is considered an *ex officio* member. They are:

- William C. Nelson (Chairman)
- David L. Bodde
- Gary D. Forsee
- Luis A. Jimenez
- James A. Mitchell
- Linda H. Talbott
- Robert H. West (*ex officio*)

Mr. Forsee became a director and member of the Committee in December 2008. Mr. Ernst resigned from the Board in January 2009.

The Committee sets the executive compensation structure and administers the policies and plans that govern compensation for the NEOs and other executive officers. The Committee's charter has been approved by our Board, and decisions by the Committee are reviewed with, and approved by, the independent members of the full Board. A copy of the charter can be found on the Company's website at *www.greatplainsenergy.com*.

Role of Executive Officers

Each year, Mr. Chesser submits to the Committee a performance evaluation and compensation recommendation for each of the NEOs, other than himself. The performance evaluation is based on factors such as achievement of individual, departmental, and Company results, as well as an assessment of leadership accomplishments. The Committee reviews these recommendations and makes final recommendations for Board approval. Annual performance metrics and goals for incentive plans are also developed through a process in which management, including the CEO, develops preliminary recommendations that the Committee considers in the development of final recommendations for Board approval.

While Mr. Chesser routinely attends meetings of the Committee, he is not a member and does not vote on Committee matters. Only members of the Committee may call Committee meetings. In addition, there are certain portions of Committee meetings when he is not present, such as when the Committee is in closed executive session or discusses his performance or individual compensation. Mr. Chesser's compensation levels and performance goals are recommended by the Committee for approval by the Board. The Senior Vice President—Human Resources and Corporate Secretary and the external executive compensation consultant were consulted in this process in 2008, as described in the next section.

As established by the Committee, Messrs. Chesser and Downey may grant awards of restricted stock under the Company's LTIP to non-executive employees. Actions taken by those individuals are reported back to the Board and Committee.

Role of Compensation Consultant

The Committee retains Mercer as its third-party compensation consultant. Mercer was selected by the Committee several years ago following presentations from other consulting firms and based on their overall capabilities in the area of executive compensation. Mr. Michael Halloran is the Company's lead consultant who works with the Committee. Mr. Halloran is a Worldwide Partner at Mercer and has more than 25 years of experience in executive compensation.

On a periodic basis, Mercer provides the Committee with a comprehensive review of the Company's executive compensation programs, including plan design; all executive benefit programs; and a review of pay positioning versus performance to evaluate the magnitude of pay versus performance. On an annual basis, Mercer performs a competitive review and analysis of base salary and variable components of pay, relative to survey market data and the Company's identified peer group. Mercer recommends to the Committee the peer group which might be used; the structure of plans; the market data which should be used as the basis of comparison for base salaries and incentive targets; and conducts comparisons and analyses of base and variable components. Mercer provides detailed information on base salaries, annual incentives, long-term incentives, and other specific aspects of executive compensation for each NEO, as well as Mercer's overall findings and recommendations. Comparisons of executive compensation are made to energy industry data, general industry data, and peer proxy data, as appropriate. The compensation consultant neither determines, nor recommends, the

amount of an executive's compensation since it is not in a position to evaluate individual executive performance.

While Mercer is engaged by, and takes direction from the Committee, the Senior Vice President—Human Resources and Corporate Secretary (who is not a NEO) works directly with Mercer's consultants to provide information, coordination, and support. To assure independence, the Committee also pre-approves all other work unrelated to executive compensation proposed to be provided by Mercer, if the fees would be expected to exceed $10,000. The fees were below this threshold in 2008.

Role of Peer Group

The proxy peer group, as recommended by Mercer and approved by the Committee, consists of 12 organizations of similar character, industry, revenue size, and market capitalization, as compared to the Company. The peer group companies relied upon to assist in formulating the executive compensation for 2008 include:

Allegheny Energy	NSTAR	Sierra Pacific Resources
Alliant Energy	Pinnacle West Capital	TECO Energy Inc.
Cleco	PNM Resources	Unisource Energy
DPL	Portland General Electric	Westar Energy

When other surveys are relied on, Mercer conducts, where possible, regression analyses to adjust the compensation data for differences in the companies' revenues, allowing the Company to compare compensation levels to similarly-sized companies. Other surveys used by Mercer to assist in formulating its recommendations to the Company include the Mercer Energy Survey; Watson Wyatt Top Management Survey: Utilities Sector; Watson Wyatt Top Management Compensation Survey; Towers Perrin Energy Executive Survey; and the Mercer Executive Compensation Survey. The actual number of participants vary by survey and are too numerous to list. Survey details are generally viewed as proprietary by the survey sponsors.

Philosophy and Objectives of the Company's Compensation Program

Great Plains Energy's shareholders and customers will be best served when the Company is able to attract and retain key talent. Recognizing the strategic imperatives before the Company, Great Plains Energy is committed to providing total remuneration levels which are competitive with jobs of similar scope within the utility market. This will be accomplished through a combination of base salary, benefits, and performance-based annual and long-term incentives. In general, the Company's goal is to provide base salaries around the median of comparable companies, with opportunities for higher levels of compensation through performance-based incentives. Incentive program targets and structure will be consistent with those offered in the utility sector, and incentive measures will be appropriately tied to both shareholder and customer interests.

The three main objectives of the Company's Executive Compensation Program are:

1. To Attract and Retain Highly Qualified and Experienced Executives

All of the NEOs held senior positions at other companies and each brought considerable industry and business expertise to the Company. While the Company's goal is to provide base salaries at the median of comparable companies with opportunities for variable compensation at higher levels based on performance, on occasion, the Company pays above-market base salaries in order to attract and retain specific talent.

2. To Motivate Executives to Achieve Strong Short-Term and Long-Term Financial and Operational Results

The Committee believes that pay and performance should be linked with objectives for which employees can have a clear line of sight, and this is principally accomplished through variable compensation opportunities. While the Committee has not elected to adopt policies for allocating between long-term and currently-paid-out compensation, or between cash and non-cash compensation, it does believe in putting more pay at risk as employees move to higher levels of responsibility with more direct influence over the Company's performance. Variable compensation targets for the NEOs (except Mr. Malik) represent between 57% and 71% of total direct compensation, constituting significant levels of pay at risk. The Committee uses a balanced scorecard approach in setting the NEOs' annual incentive plan goals, which includes financial, operational, and individual components, along with key operational and/or financial measures for the long-term plan, which place a much greater emphasis on increasing long-term shareholder value.

During the sale process of Strategic Energy in 2008, the Committee recommended, and the independent members of the Board approved, the cash payment of incentive compensation that would have been payable, at target performance, had customary grants been made in 2008 pursuant to Strategic Energy's annual and long-term incentive compensation plans, prorated for the period of time between the beginning of the year and the sale closing date. This was done to provide incentives for Strategic Energy executives to remain with the company and focus on preserving the value of the business through the sale process.

3. To Ensure the Alignment of Management Interests with Those of Shareholders

The Committee believes that a substantial portion of total compensation for its NEOs should be delivered in the form of equity-based incentives. In 2008, for Messrs. Chesser, Downey, Bassham, Marshall, and Easley, 75% of long-term incentive grants were in the form of performance shares which, if earned after three years based on total return to shareholders, would be paid out in Company stock. As noted, Mr. Malik received a pro-rata long-term incentive amount in 2008, paid in cash. In order to provide some degree of retention protection, the remaining 25% of the long-term grant was in the form of time-based restricted shares. In addition, the Committee has also implemented share ownership guidelines for executives to further align their compensation with shareholder interests. The guidelines include the value of Company shares executives are expected to acquire and hold, and reflect a level of five times base salary for Mr. Chesser; four times base salary for Mr. Downey; and three times base salary for Messrs. Bassham, Marshall, and Easley. In addition, in 2007 the Committee and Board also implemented "hold 'til" requirements, which require the executive to refrain from disposing of shares received under the Company's LTIP, except to satisfy obligations for payment of taxes relating to those shares, until the share ownership guidelines are met and maintained.

Analysis of Executive Compensation

The elements of compensation are:

1. Cash compensation in the form of base salaries, annual incentives, and, in certain instances, discretionary bonuses;
2. Equity compensation under the Company's LTIP;
3. Perquisites and generally available employee benefits;
4. Deferred compensation;
5. Post-termination compensation;
6. Pension plan and supplemental pension plan; and
7. 401(k) plan.

1. Cash Compensation

Cash compensation to our NEOs includes (i) a market-competitive and performance-driven base salary; and (ii) annual short-term incentive plans. The Committee has not chosen to target a specific percentage of total compensation for NEOs to be delivered in cash or cash opportunities as it believes this will vary based on the NEO's position and individual performance and circumstance. However, it does believe that, in general, the level of cash opportunity should decrease in proportion to equity compensation as individuals move to higher levels of responsibility.

Base Salary

Base salaries are reviewed at the February Committee meeting, approved by the Board, and, if adjusted, made retroactive to the first of the year. The Committee considers performance evaluations and base salary recommendations submitted by Mr. Chesser for the NEOs, other than himself. Mr. Chesser's performance evaluation is conducted and salary recommendation is prepared by the Committee. Salary recommendations are not determined by formula, but instead take into consideration job responsibilities, level of experience, individual performance, internal comparisons, comparisons of the salaries of executives in similar positions at similar companies obtained from market surveys, and other competitive data and input provided by Mercer. Individual performance evaluations are based on qualitative factors. The factors considered in the evaluations include, among others, the following: personal leadership; engagement of employees; disciplined performance management; accountability for results; community involvement; and major accomplishments during the performance period. For 2008, the base salary of each NEO was benchmarked against comparable positions reported in peer group proxies, utility surveys, and general industry surveys. Our general goal is to set base salaries to approximate the median salaries of individuals in comparable positions in companies of similar size within the relevant industry or function. Differences in base salaries between the NEOs are primarily due to differences in job responsibilities and base compensation market levels. The responsibilities of Mr. Chesser, as CEO, span all aspects of the Company, and his base salary reflects this responsibility. In contrast, the responsibilities of the other NEOs are narrower in scope.

Messrs. Chesser, Downey, Bassham, Easley and Malik received base salary increases effective January 1, 2008, of 10.3%, 4.3%, 15.4%, 1.5% and 4.1%, respectively. Larger percentage increases were given when the salaries were significantly less than market medians and the NEOs demonstrated a high level of performance. Mr. Marshall received an increase of 6.0% effective January 1, 2008, and an increase of 9% effective August 5, 2008, the latter to reflect the greater responsibilities associated with his promotion to Executive Vice President—Utility Operations.

Annual Incentives

The Company's annual incentive plans are based upon Company-wide and business unit financial and operational metrics, as well as individual performance. Metric levels are established so that the target level reflects the business plan and has a 50% probability of achievement. The threshold and maximum levels are established to have approximately 80% and 20% probabilities of achievement, respectively. The Committee reviews management's recommendations of goals and metrics, makes any revisions, and recommends the final goals and metrics to the Board for its approval. In establishing final goals, the Committee assures that:

- Incentives are aligned with the strategic goals set by the Board;
- Goals are sufficiently ambitious so as to provide a meaningful incentive; and
- Bonus payments, assuming target levels are met, will be consistent with the overall compensation program established by the Committee.

The Committee developed, with input from Mercer, a structure for the annual incentive plan for all executives, including NEOs, which provides a financial objective of Company core earnings (which is explained on page 29) weighted at 40%; 40% reflecting key Great Plains Energy or KCP&L business objectives; and 20% as a discretionary individual performance component. The 20% individual component includes, but is not limited to, a subjective review of the individual's personal leadership; engagement of employees; disciplined performance management; accountability for results; and community involvement. Target incentives for each NEO were established as a percentage of base pay, using survey data provided by Mercer for comparable positions and markets, as well as comparisons for internal equity. For 2008, annual incentive plan targets as a percentage of base salaries for Messrs. Chesser, Downey, Bassham, and Easley were 100%, 70%, 50% and 50%, respectively. Mr. Marshall's annual incentive target was increased from 50% to 60% in August 2008 (prorated over the year) to reflect his increased responsibilities as Executive Vice President—Utility Operations. As noted, Mr. Malik was eligible for a pro-rata amount based on a target of 60%.

The basic structure of the annual incentive plan provides for 100% payout for target performance for each goal, with 50% payable at the threshold level of goal performance and 200% payable at the maximum level of goal performance. Goal performance is extrapolated between the threshold and target levels, and between target and maximum levels. Performance results for any goal which is less than threshold will result in a zero payment for that goal. Failure to achieve at least the threshold level of the core earnings objective results in no payouts under the annual incentive plan, regardless of the level of achievement of the other objectives.

After considering the performance criteria and results, the Committee approves, and occasionally uses its discretion in determining, the final amount of the individual award. Under the terms of the annual incentive plan, the Committee retains discretion to modify all components of the annual incentive plan at any time, and to determine the final amount of awards notwithstanding the achievement (or lack thereof) of goals. Discretion has been exercised in the past regarding the 20% individual performance component. The Committee did not use any discretion with respect to any component of the plan in 2008.

There were no payouts, including for the 20% discretionary component, under the 2008 annual incentive plan because the threshold core earnings level was not achieved. This is the same result as for the 2007 annual incentive plans: failure to achieve the threshold level of the core earnings objective resulted in no payouts, including for the 20% discretionary component. The following table summarizes the 2008 annual incentive plan, year-end results, and payout levels:

GREAT PLAINS ENERGY/KCP&L 2008 ANNUAL INCENTIVE PROGRAM

Measure	Weighting	50% Payout Level	100% Payout Level	200% Payout Level	Actual Performance Result	Payout Percentage (1)
Core earnings per share	40%	$1.60	$1.67	$1.77	$1.44	0%
System Average Interruption Duration Index	5%	99.5 minutes	95.5 minutes	90.0 minutes	67.0 minutes	0%
% equivalent availability—coal and nuclear	10%	77.25%	80.0%	82.0%	77.8%	0%
OSHA incident rate	10%	4.0	3.4	3.1	3.0	0%
J D Powers Customer Satisfaction Index—residential	5%	Bottom Half of Tier II	Top Half of Tier II	Tier 1	Tier 1	0%
Comprehensive Energy Plan Progress	10%	Qualitative measure; judgment made on collective work progress			100%	0%
Individual performance	20%	Discretionary			—	0%
Total	100%					0%

(1) A 0% payout percentage is shown for all objectives due to the failure to achieve the threshold level of performance of the core earnings per share objective.

Core earnings and core earnings per share are financial measures that differ from earnings and earnings per share calculated in accordance with generally accepted accounting principles (GAAP). Core earnings, as used for the 2008 annual incentive compensation plan, excluded mark-to-market impacts of certain contracts, changes in composite tax rates, certain Aquila acquisition transition costs and the release of legal reserves, and included the operational results of Strategic Energy for the period it was owned by Great Plains Energy.

From time to time, the Committee and Board may grant a discretionary bonus to a NEO or other executive for extraordinary contributions or achievements. There were no discretionary bonuses granted to NEOs in 2008.

The Committee has not yet established an annual incentive program for 2009. The Committee is undertaking a comprehensive review of the design of the Company's annual and long-term incentive compensation programs in light of various factors, including past payouts (or lack thereof), potential future economic and financial market conditions, and the Company's current operating and financial plans.

Cash Portion of Strategic Energy's Long-Term Incentives

Mr. Malik and other officers of Strategic Energy participated under long-term incentive programs designed specifically for Strategic Energy. Strategic Energy's long-term incentives were designed

principally to reward sustained value creation through the achievement of long-term financial and operating performance goals. Strategic Energy's long-term incentives were largely cash-based, because the Committee and Board believed companies with which Strategic Energy competed for executive talent were more likely to offer cash-based long-term incentives, rather than equity-based long-term incentives. As a result, Mr. Malik is the only NEO that received cash-based long-term incentives. Mr. Malik's long-term target was 150% of base pay.

However, based on the Company's overall compensation philosophy, an equity component was utilized in Strategic Energy's long-term incentives. Mr. Malik's 2006-2008 long-term grants consisted of 25% time-based restricted stock, with the remaining cash-based component based 80% on Strategic Energy performance goals and 20% on Great Plains Energy performance goals. Components based on Strategic Energy's performance included payout opportunities ranging from 0% to 300%. The structure of Strategic Energy's long-term incentive program changed for grants in 2007, so that the target award included 50% performance shares and 50% cash, with total payouts ranging from 0% to 275% of target, plus accrued dividends on the paid-out performance shares, if any. The change in 2007 resulted in the equity portion of this program more directly reflecting Strategic Energy's performance.

The Committee chose to provide significant long-term award opportunities to Strategic Energy executives to motivate the highest levels of performance within its highly competitive, unregulated environment. Strategic Energy's executives did not have a defined benefit pension plan, as do other Great Plains Energy and KCP&L executives.

Great Plains Energy announced in 2007 that it was reviewing strategic and structural alternatives for Strategic Energy. Strategic Energy's long-term incentive programs did not explicitly provide for payment of outstanding grants in the event of a change in control of Strategic Energy, in contrast to the provisions of Great Plains Energy's LTIP regarding a change in control of Great Plains Energy. In order to provide incentives for Strategic Energy executives to remain with the company and focus on preserving the value of the business through the review and subsequent sale process, and consistency with the LTIP change in control provisions related to Great Plains Energy, Strategic Energy's long-term incentive programs were clarified to provide for the payment of outstanding equity and cash awards, at target, in the event of a change in control of Strategic Energy. Strategic Energy was sold in June 2008, and Mr. Malik received $802,500 in cash, reflecting the target amount of the cash portions of his 2006-2008 and 2007-2009 long-term awards, as well as a cash payment of $96,531, which was the pro-rata amount at target had a customary long-term incentive grant been made for the 2008-2010 period. His outstanding restricted stock vested at that time, and he also received a payment of his outstanding performance shares, at target, plus accrued cash dividends. These payments and vestings were not conditioned on the achievement of any performance metrics.

2. *Equity Compensation*

As previously explained, the Committee believes that a substantial portion of compensation for NEOs should be in the form of equity in order to best align executive compensation with shareholder interests. The Committee does not believe any of the NEOs have accumulated equity amounts, or previously been given the opportunity for significant amounts of equity ownership, that warrant special consideration in granting future equity awards.

The Great Plains Energy LTIP was last approved by shareholders in May 2007 and allows for grants by the Committee of stock options, restricted stock, performance shares, and other stock-based awards. The Committee discontinued making any new stock option grants in late 2003, because it believed motivating executives based solely on stock price appreciation was not entirely consistent with the best interests of its shareholder base. Since that time, the Committee has used a mix of time-based restricted shares and performance shares that vest solely on the basis of the attainment of performance goals. While the Committee believes that performance shares should generally account for the majority

of annual long-term grants, this could change in any year based on the needs of the Company and the characteristics of its executive team.

While directors, officers and employees of the Company are eligible for equity awards under the LTIP, none of them have any right to be granted awards. The Committee, in its discretion, may approve an equity award or awards for officers and employees, including NEOs. When the Committee approved awards in 2008 for officers, it calculated the awards using a cash value determined by multiplying the officers' base salary by a target percentage chosen by the Committee. The target percentage is based on both internal comparisons and survey data provided by Mercer, which provides long-term incentive information on comparable positions at comparable companies, and/or markets in which the Company competes for talent. Generally, the Committee has established targets at the 50th percentile. In 2008, long-term incentive target percentages for Messrs. Chesser, Downey, Bassham, Marshall, and Easley were 150%, 115%, 85%, 85% and 85%. These target percentages are consistent with the Company's incentive compensation practices in recent years, and resulted in the following long-term incentive grants of restricted stock and performance shares in 2008:

Name	Restricted Stock	Performance Shares (at target)
Mr. Chesser	11,442	34,325
Mr. Downey	5,373	16,119
Mr. Bassham	3,040	9,118
Mr. Easley	2,278	6,833
Mr. Marshall	2,878	8,632

Performance share grants are for the three-year performance period of January 1, 2008, through December 31, 2010, and vest as of the end of the period. The restricted stock grants referenced in the above table vest on February 5, 2011. Restricted stock is typically, but not always, granted at the February Board meeting, effective on the meeting date. When restricted shares are granted in conjunction with the employment of a new executive or for other reasons, the effective dates are the date of hire, the date of Committee or Board action, or a date following the Committee/Board meeting. We do not have any program, plan, or practice of timing grants in coordination with the release of material non-public information. As of May 2007, when our shareholders approved amendments to our LTIP, the Fair Market Value calculation for issuance of equity grants is based on the closing market price for the Company's common stock, as reported on the NYSE for the applicable date.

Performance shares can pay out at the end of the performance period from 0% to 200% of the target amount, based on performance. The sole performance metric has been total shareholder return ("TSR") compared to the Edison Electric Institute ("EEI") index of electric companies. The EEI index is a recognized, publicly-available index which the company uses as prepared by EEI, and with no additions or deletions. The Committee believes TSR is a strong indicator of shareholder value and is influenced both by successful execution by executives, as well as market perceptions of the strength and future prospects of the Company. Great Plains Energy's TSR percentile ranking in the EEI index determines the percentage payout our executives will receive, as follows:

Percentile Rank	Percentage Payout
81st and above	200%
65th to 80th	150%
50th to 64th	100%
35th to 49th	50%
34th and below	0%

There is no payout of performance shares, regardless of the TSR percentile ranking, if the Great Plains Energy TSR is negative for the applicable three-year period. Awards are paid out in shares of Great Plains Energy common stock, unless otherwise determined by the Board. Dividends which accrue on the performance shares will be paid in cash at the end of the performance period, based on the number of performance shares earned, if any.

The following table summarizes the performance share component of the 2006-2008 Long-Term Incentive Plan for Great Plains Energy/KCP&L, including year-end results and payout levels.

2006-2008 GPE/KCP&L LONG-TERM INCENTIVE PLAN RESULTS

Scorecard Goal	Percentage of Total Goal	Three-Year Target	Three-Year Results	Percentage Payout
Three-Year Total Shareholder Return	100%	50th Percentile	15th Percentile	0.00%
Total Payout (up to 200% of target amount)				**0.00%**

In February 2008, Messrs. Downey, Easley, and Marshall received payouts of 5,507, 3,810, and 4,482 shares, respectively, plus associated accrued cash dividends, from the 2005-2007 performance share grants, and Mr. Easley became vested in 10,000 shares resulting from a special one-time restricted stock grant in February 2005. In March of 2008, Mr. Bassham became vested in 9,083 shares (plus 1,672 shares through reinvested dividends) resulting from a grant of restricted stock at the time of his employment in March 2005, and Mr. Marshall became vested in 20,275 shares (plus 3,732 shares through reinvested dividends) resulting from a grant of restricted stock at the time of his employment in May 2005.

As discussed above, the equity portion of Strategic Energy's long-term incentive programs was payable, at target, in the event of a change in control of Strategic Energy. The change in control occurred in June 2008, and Mr. Malik was paid 10,325 shares in respect of the target amount of his performance shares, and became vested in 6,350 shares of restricted stock and reinvested dividends.

The Committee has not established a long-term incentive program for 2009. The Committee is undertaking a comprehensive review of the Company's annual and long-term incentive compensation programs in light of various factors, including past payouts (or lack thereof), potential future economic and financial market conditions, and the Company's current operating and financial plans.

3. Perquisites

NEOs are eligible to receive various perquisites provided by or paid for by the Company. These perquisites are generally consistent with those offered to executives at comparable organizations with which we compete for executive talent, and are important for retention and recruitment. The NEOs are also eligible for employment benefits that are generally available to all employees, such as vacation and medical and life insurance.

As shown in the Summary Compensation Table on page 36, all NEOs are eligible for participation in comprehensive financial planning services provided by a national financial counseling firm; executive health physicals; a car allowance; memberships in social clubs and, in limited situations, country clubs; use of certain equipment for personal use, such as home computer equipment; and access to sporting events and other entertainment which may be used for personal use on a limited basis. On occasion, the Company may also provide for spousal travel and accommodations when accompanying the executive on out-of-town trips. As required by current tax laws, the executive is assessed imputed income taxes on the subsidized or reimbursed amounts.

4. Deferred Compensation Plan

The Company's Deferred Compensation Plan (DCP) allows selected employees, including NEOs, to defer the receipt of up to 50% of base salary and 100% of awards under the Annual Incentive Plan. An earnings rate is applied to the deferral amounts, which is annually determined by the Committee and based on the Company's weighted average cost of capital. For 2008, the rate was 9%. In addition, the Plan provides for a matching contribution in an amount equal to 50% of the first 6% of base salary deferred, or 100% of the first 6% of base salary, bonus and incentive pay deferred, depending on the retirement option selected by the individual, and reduced by the matching contribution made for the year to the individual's 401(k) plan account. The DCP is a nonqualified and unfunded plan, and is shown in external market comparisons to be a common element of an executive rewards strategy.

5. Post-Termination Compensation

The Company has entered into severance agreements and other compensation and benefit agreements with its executive officers, including NEOs, to help in securing their continued employment and dedication, particularly in situations such as a change in control when an executive may have concerns about his or her own continued employment. The Company believes these agreements and benefits are important recruitment and retention devices, as virtually all of the companies with which we compete for executive talent have similar agreements in place for their senior executives.

Change in Control Severance Agreements

The Company has change in control agreements, updated in 2006, with all its executive officers, including the NEOs, to ensure their continued service, dedication, and objectivity in the event of a transaction that would change the control of the Company. These agreements provide for payments and other benefits if the officer's employment terminates for a qualifying event or circumstance, such as being terminated without "Cause" or leaving employment for "Good Reason" as these terms are defined in the agreements. All the agreements require a double trigger so that both a change in control and a termination (actual or constructive) of the executive's employment must occur, with very limited exceptions. Generally, the Committee and Board determined the eligibility for potential payments upon change-in-control, based on comparable practices in the market. The Committee believes it is not uncommon for the chief executive officer and chief operating officer to be covered under a "three times" change-in-control agreement, nor is it uncommon for other senior level officers to be covered under a "two times" change-in-control agreement. Messrs. Chesser and Downey are eligible for three times base salary and incentive in the event of a change-in-control and Messrs. Bassham, Marshall, and Easley are eligible for two times base salary and incentive. Mr. Malik was eligible for three times base salary and incentive in the event of a change in control of Strategic Energy, which occurred with the sale of Strategic Energy. We believe the terms and protection afforded are in line with current market practice.

Change in control agreements were not triggered for any Great Plains Energy or KCP&L employee as a result of the acquisition of Aquila, Inc., in July of 2008.

Additional information, including a quantification of benefits that would have been received by NEOs had termination occurred on December 31, 2008, is found under the heading "Potential Payments upon Termination or Change-in-Control" beginning on page 49.

Other Agreements

The Committee has historically wished to minimize the use of employment agreements to the extent possible. Mr. Malik is the only NEO who had a full written employment agreement, providing for three times annual salary and bonus in the event he was terminated without cause or terminated for good reason. Because Mr. Malik's employment with Strategic Energy was terminated in connection with

the sale of Strategic Energy, benefits were paid under his change in control agreement and not his employment agreement.

As discussed on page 53, under the terms of Mr. Chesser's employment offer letters, Mr. Chesser is entitled to receive three times annual salary and bonus if he is terminated without cause prior to reaching age 63. After age 63, any benefit for termination without cause would be one times annual salary and bonus until age 65. Similarly, under the terms of his employment offer letter, Mr. Marshall is entitled to receive two times annual salary and bonus in the event he is terminated other than for cause. Messrs. Chesser and Marshall orally accepted the offers and commenced employment. The terms described above are enforceable against the Company through the judicial process.

As discussed in the section titled "Pension Benefits" starting on page 46, pursuant to the terms of the employment offer letters, Messrs. Chesser and Marshall receive credit for two years of service for every one year of service earned under the Pension Plan. Mr. Downey, who started service with the Company several years before either Mr. Chesser or Mr. Marshall, did not have a similar pension benefit. In 2008, the Committee determined to provide a pension enhancement to Mr. Downey. In making this determination, the Committee considered the key role that Mr. Downey, as President and Chief Operating Officer, has in the Company's operations and power plant construction program, as well as the pension benefit equity between him and Mr. Marshall, who reports to Mr. Downey. The Committee concluded that it was in the best interest of the Company to provide an enhanced retirement benefit to Mr. Downey, structured in a manner to incentivize him to remain with the Company through the completion of the current power plant construction project. As a result, in August of 2008, the Company entered into an enhanced retirement benefit agreement with Mr. Downey which provides a $700,000 lump sum payment upon his separation from service provided that (i) he remains until his 65th birthday and (ii) he remains in good standing with the restricted covenants set forth in his change in control severance agreement.

In December of 2008, the Company entered into an agreement with Mr. Easley that provided for a lump sum payment of $1,225,000 in connection with his resignation as of January 2, 2009, and certain releases and undertakings to assist the Company after resignation. The agreement was the result of negotiation between the Company and Mr. Easley. In evaluating the reasonableness of the agreement, the Committee considered Mr. Easley's contributions to the Company, the fact that the resignation would cause the forfeiture of outstanding restricted stock and performance share grants, past practice of the Company, the benefit of resolving all potential claims, and the benefits of a smooth transition of duties to Mr. Easley's successor.

6. Pension Plan and Supplemental Pension Plan

The Company maintains a funded, tax-qualified, noncontributory defined benefit plan (the "Pension Plan") that covers employees of Great Plains Energy and KCP&L, including all NEOs except Mr. Malik. Benefits under the Pension Plan are based on the employee's years of service and the average annual base salary over a specified period.

The Company also has a Supplemental Executive Retirement Plan ("SERP") for its executives, including all NEOs except Mr. Malik. This unfunded plan essentially provides the difference between the amount that would have been payable under the Pension Plan in the absence of Internal Revenue Service tax code limitations and the amount actually payable under the Plan. It also adds a slightly higher benefit accrual rate than the Pension Plan.

Based on provisions in their employment offer letters as previously described, both Mr. Chesser and Mr. Marshall receive credit for two years of service for every one year of service earned under the Pension Plan, payable under the SERP.

In 2007, management employees of Great Plains Energy and KCP&L were given a one-time election to remain in their existing Pension Plan and 401(k) Plan ("Old Retirement Plan"), or choose a

new retirement program that includes a slightly reduced benefit accrual formula under the Pension Plan paired with an enhanced benefit under the 401(k) Plan ("New Retirement Plan"). Elections were effective January 1, 2008. Messrs. Bassham and Marshall elected to participate in the New Retirement Plan.

7. 401(k) Plan

The Great Plains Energy 401(k) Plan is offered to all employees as a tax-qualified retirement savings plan.

- Employees in the Old Retirement Plan can contribute up to 40% of base pay. After one year of employment, the Company matches 50% of the first 6% of pay that is contributed. Employees are fully vested in the entire match and associated earnings after 6 years.
- Employees in the New Retirement Plan can contribute up to 75% of base pay, bonus, incentive, and overtime pay. The Company matches 100% of the first 6% of total pay that is contributed. All contributions vest immediately.
- The Company match is made with Great Plains Energy stock, although a participant may diversify or transfer out of Company stock and reinvest his or her plan account in different investments.
- Contributions are limited by the tax code.

Tax and Accounting Implications

With respect to Section 162(m) of the Internal Revenue Code, the Committee believes that while it is the Company's goal to be as tax efficient as possible, the Company's shareholders are best served by not restricting the Committee's and the Company's discretion and flexibility in developing compensation programs. The unrealized tax benefit by the Company in 2008, as a result of lost deductions, was $700,909.

COMPENSATION COMMITTEE REPORT

The Compensation and Development Committee of the Board reviewed and discussed with management the Compensation Discussion and Analysis ("CD&A") contained in this proxy statement and, based on such reviews and discussions, recommended to the Board that the CD&A be included in the Company's proxy statement and Annual Report on Form 10-K for the fiscal year ended December 31, 2008 for filing with the SEC.

Compensation and Development Committee

William C. Nelson, Chair
David L. Bodde
Gary D. Forsee
Luis A. Jimenez
James A. Mitchell
Linda H. Talbott
Robert H. West *(ex officio)*

EXECUTIVE COMPENSATION

Executive Compensation is more fully explained in the CD&A section, starting on page 23. The following table shows the total salary and other compensation awarded to and earned for services rendered in all capacities to Great Plains Energy and its subsidiaries by Mr. Chesser, our Chief Executive Officer, Mr. Bassham, our Chief Financial Officer, and Messrs. Downey, Easley and Marshall, who were our three other most highly compensated executive officers as of the end of the year, and Mr. Malik, who was an executive officer until the sale of Strategic Energy in June 2008. We have omitted from the table the column titled "Bonus," because compensation earned under our annual incentive plans is reported in the "Non-Equity Incentive Plan Compensation" column.

SUMMARY COMPENSATION TABLE

Name and Principal Position (a)	Year (b)	Salary ($) (c)	Stock Awards [1] ($) (e)	Option Awards [1] ($) (f)	Non-Equity Incentive Plan Compensation [2] ($) (g)	Change in Pension Value and Nonqualified Deferred Compensation Earnings [3] ($) (h)	All Other Compensation [4] ($) (i)	Total ($) (j)
Mr. Chesser Chairman and Chief Executive Officer—Great Plains Energy	2008	800,000	2,095,914	—	—	565,030	63,749	3,524,693
	2007 [5]	725,000	1,553,694	—	—	692,253	236,452	3,207,399
	2006	650,000	1,094,691	—	936,650	281,177	105,499	3,068,017
Mr. Downey President and Chief Operating Officer—Great Plains Energy	2008	490,000	1,117,169	—	—	847,900	54,882	2,509,951
	2007 [5]	470,000	899,517	—	—	280,695	163,380	1,813,592
	2006	450,000	636,411	3,215	424,305	172,201	68,101	1,754,233
Mr. Bassham Executive Vice President—Finance & Strategic Development & Chief Financial Officer—Great Plains Energy	2008	375,000	632,398	—	—	39,620	58,475	1,105,493
	2007 [5]	325,000	513,852	—	—	44,656	119,241	1,002,749
	2006	300,000	183,297	—	223,650	27,750	49,382	784,079
Mr. Easley Senior Vice President—Supply—Kansas City Power & Light Company	2008	281,000	577,496	—	—	101,565	1,274,179	2,234,240
Mr. Malik President and Chief Executive Officer—Strategic Energy	2008	227,532	296,804	—	1,014,657	11,678	2,375,559	3,926,230
	2007 [5]	440,000	231,436	—	495,000	21,111	65,874	1,253,421
	2006	420,000	218,558	—	1,006,591	9,963	85,847	1,740,959
Mr. Marshall Executive Vice President—Utility Operations—Kansas City Power & Light Company	2008	369,583	713,408	—	—	168,028	56,837	1,307,856
	2007 [5]	335,000	679,096	—	—	235,825	137,738	1,387,659
	2006	325,000	294,024	—	203,450	125,637	76,306	1,024,417

(1) The amounts shown in these columns are the compensation expense as recognized for financial statement reporting purposes with respect to the fiscal year in accordance with the Financial Accounting Standards Board Statement of Financial Accounting Standard No. 123 (revised 2004), "Share-Based Payment" ("FAS 123R") for restricted stock, performance shares and options granted under our LTIP. See note 11 to the consolidated financial statements included in our Annual Report on Form 10-K for the year ended December 31, 2008, for a discussion of the relevant assumptions used in calculating these amounts. The amounts shown are exclusive of the estimate of forfeitures related to service-based vesting conditions, as required by SEC rules. For further information on these awards, please see the Grants of Plan-Based Awards and Outstanding Equity Awards at Fiscal Year-End tables later in this proxy statement.

The Company is required by accounting rules to recognize compensation expense for performance share awards, whether or not common stock is actually paid at the end of the performance periods. The Company is not permitted under the accounting rules to reverse this expense in the event there is a reduced, or no, payout of performance share awards at the end of the performance periods. As a result, we are required to show in the "Stock Awards" column the amount of compensation expense recognized each year for performance share awards, regardless of the actual payout of performance shares. There were no payouts of performance shares for the 2006-2008 performance period for any of our named executive officers (other than Mr. Malik). In addition, the amount shown for Mr. Easley also reflected compensation expense recognized for his performance share grants for the 2007-2009 and 2008-2010 performance periods and restricted stock grants outstanding as of December 31, 2008. Mr. Easley forfeited such awards as of his January 2, 2009, resignation date.

(2) The amounts shown in this column constitute cash payments made under our annual and long-term incentive plans. Mr. Malik is the only NEO who received cash payments under long-term incentive plans. The amounts shown for Mr. Malik include $592,744, $495,000 and $802,500 paid in cash in 2006, 2007 and 2008, respectively, under long-term incentive plan grants made prior to 2008. The amount shown for Mr. Malik for 2008 also includes $212,157, reflecting a cash payment of the amount of annual and long-term incentive compensation that would have been payable, at target performance, had customary grants been made in 2008 pursuant to Strategic Energy's annual and long-term incentive compensation plans, prorated for the period of time between the beginning of 2008 and the closing date of the Strategic Energy sale.

(3) The amounts shown in this column include the aggregate of the increase in actuarial values of each of the officer's benefits under our pension plan, SERP and other supplemental retirement plans, and the above-market earnings on compensation that is deferred on a non-tax qualified basis. Following are the amounts of these items attributable to each NEO:

Name	Change in Pension Value ($)	Change in SERP and Other Supplemental Retirement Plan Value ($)	Above-Market Earnings on Deferred Compensation ($)
Mr. Chesser	54,722	466,748	43,560
Mr. Downey	50,910	740,747	56,243
Mr. Bassham	18,727	15,675	5,218
Mr. Easley	55,297	32,462	13,806
Mr. Malik	—	—	11,678
Mr. Marshall	34,426	98,548	35,054

The amount shown for Mr. Downey in the "Change in SERP and Other Supplemental Retirement Plan Value" column includes $84,239 for the change in actuarial present value of his SERP benefit, and $656,508 for the actuarial present value of the supplemental retirement and severance benefit granted to him in 2008. No other NEO has such a benefit.

(4) These amounts include the value of perquisites and personal benefits that are not generally available to all employees. These perquisites and personal benefits are of the following types: (A) employer match of contributions to our 401(k) plans (which are contributed to the maximum extent permitted by law to the 401(k), with (B) any excess contributed to the officers' accounts in our non-qualified deferred compensation plan); (C) flexible benefits and other health and welfare plan benefits; (D) car allowances; (E) club memberships; (F) executive financial planning services; (G) parking; (H) spouse travel; (I) personal use of company tickets; (J) matched charitable donations; (K) executive health physicals; and (L) vacation days sold back to the Company, as detailed below. All amounts shown are in dollars.

Name	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
Mr. Chesser	6,900	17,100	14,120	7,200	1,840	11,440	780	369	—	4,000	—	—
Mr. Downey	6,900	7,800	13,990	7,200	1,840	11,440	780	468	—	2,500	1,964	—
Mr. Bassham	13,800	4,350	19,065	7,200	1,840	11,440	780	—	—	—	—	—
Mr. Easley	6,900	1,530	14,009	7,200	—	11,440	780	—	450	250	—	6,620
Mr. Malik	6,900	—	4,605	3,600	—	4,767	1,760	—	—	—	—	17,615
Mr. Marshall	13,800	5,325	13,674	7,200	1,840	11,440	780	—	—	—	2,778	—

Mr. Easley's severance payment of $1,225,000, paid in January 2009, is included with the amounts shown in the above table in the total amount shown for him in column (i) of the Summary Compensation Table.

The amount shown in column (i) of the Summary Compensation Table for Mr. Malik includes the amounts shown in the above table plus Mr. Malik's change in control severance payment of $2,336,312.

(5) The amounts shown in column (h) for the year 2007 were overstated due to an inadvertent duplication of the amount of the change in actuarial value of the SERP. The amounts shown in column (i) for the year 2007 were overstated by the amount of dividends paid on restricted stock awards; the dividends were factored into the grant date fair value. The table below provides the corrected amounts for the year 2007.

Name (a)	Year (b)	Salary ($) (c)	Stock Awards ($) (e)	Option Awards ($) (f)	Non-Equity Incentive Plan Compensation ($) (g)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($) (h)	All Other Compensation ($) (i)	Total ($) (j)
Mr. Chesser	2008	800,000	2,095,914	—	—	565,030	63,749	3,524,693
	2007	725,000	1,553,694	—	—	381,284	71,000	2,730,978
Mr. Downey	2008	490,000	1,117,169	—	—	847,900	54,882	2,509,951
	2007	470,000	899,517	—	—	189,316	71,749	1,630,582
Mr. Bassham	2008	375,000	632,398	—	—	39,620	58,475	1,105,493
	2007	325,000	513,852	—	—	32,542	52,220	923,614
Mr. Malik	2008	227,532	296,804	—	1,014,657	11,678	2,375,559	3,926,230
	2007	440,000	231,436	—	495,000	21,111	40,145	1,227,692
Mr. Marshall	2008	369,583	713,408	—	—	168,028	56,837	1,307,856
	2007	335,000	679,096	—	—	147,109	49,381	1,210,586

The following table provides additional information with respect to awards under both the non-equity and equity incentive plans. We have omitted from the table the columns titled "All other option awards: number of securities underlying options" and "Exercise or base price of option awards," because no options were granted in 2008.

GRANTS OF PLAN-BASED AWARDS

Name (a)	Grant Date (b)	Estimated Possible Payouts Under Non-Equity Incentive Plan Awards			Estimated Future Payouts Under Equity Incentive Plan Awards			All Other Stock Awards: Number of Shares of Stock or Units (#) (i)	Grant Date Fair Value of Stock and Option Awards ($) (5) (l)
		Threshold ($) (c)	Target ($) (d)	Maximum ($) (e)	Threshold (#) (f)	Target (#) (g)	Maximum (#) (h)		
Mr. Chesser	May 6, 2008 (1)	400,000	800,000	1,600,000					
	May 6, 2008 (2)				17,163	34,325	68,650		1,725,861 (4)
	May 6, 2008 (3)							11,442	287,652
Mr. Downey	May 6, 2008 (1)	171,500	343,000	686,000					
	May 6, 2008 (2)				8,060	16,119	32,238		810,463 (4)
	May 6, 2008 (3)							5,373	135,077
Mr. Bassham	May 6, 2008 (1)	93,750	187,500	375,000					
	May 6, 2008 (2)				4,559	9,118	18,236		458,453 (4)
	May 6, 2008 (3)							3,040	76,426
Mr. Easley	May 6, 2008 (1)	70,250	140,500	281,000					
	May 6, 2008 (2)				3,417	6,833	13,666		343,563 (4)
	May 6, 2008 (3)							2,278	57,269
Mr. Malik (6)	June 2, 2008	—	212,157		—				
Mr. Marshall	May 6, 2008 (1)	99,788	199,575	399,150					
	May 6, 2008 (2)				4,316	8,632	17,264		434,017 (4)
	May 6, 2008 (3)							2,878	72,353

(1) Reflects potential payments under our 2008 annual incentive plans. No payments were actually made under the plans.
(2) Consists of performance share awards under our LTIP for the period 2008-2010. Performance shares are payable in stock at the end of the performance period, depending on our total shareholder return for the period compared against the EEI index of electric utilities. The number of shares awarded can range from 0% to 200% of the target amount, as adjusted for the change in fair market value between the time of grant and the end of the award period. Dividends will be paid in cash at the end of the period on the number of shares earned.
(3) Consists of time-based restricted stock awards under our LTIP that vest on February 5, 2011.
(4) Calculated using the maximum number of shares shown in column (h).
(5) Grant date fair value on May 6, 2008 was $25.14 calculated in accordance with FAS 123R.
(6) As disclosed in footnote (2) of the Summary Compensation Table, Mr. Malik received a payment of $212,157, reflecting the cash amount of incentive compensation that would have been payable, at target performance, had customary grants been made in 2008 pursuant to Strategic Energy's annual and long-term incentive compensation plans, prorated for the period of time between the beginning of 2008 and the closing date of the Strategic Energy sale.

NARRATIVE ANALYSIS OF SUMMARY COMPENSATION TABLE AND PLAN-BASED AWARDS TABLE

Employment Agreements

Mr. Malik had a written employment agreement with Strategic Energy. Mr. Malik's employment was terminated by Strategic Energy in June 2008, in connection with the sale of the company. The agreement provided for additional compensation if Mr. Malik's employment was terminated without "Cause" by the Company, or if Mr. Malik terminated his employment for "Good Reason." This additional compensation would have been three times Mr. Malik's annual base salary, the current year's annual incentive (prorated through the termination date), and three times the average annual incentive compensation paid during the three most recent fiscal years (or such shorter period as Mr. Malik would have been employed). Because Mr. Malik's employment with Strategic Energy was terminated in connection with the sale of Strategic Energy, benefits were paid under his Change-in-Control agreement and not his employment agreement.

We agreed to certain compensation terms with Messrs. Chesser and Marshall at the time of their employment. These terms are contained in their employment offer letters. If Mr. Chesser is terminated without cause prior to age 63, he will be paid a severance amount equal to three times his annual salary and bonus; if terminated without cause between the age of 63 and 65, he will be paid a severance amount equal to the aggregate of his annual salary and bonus. In addition, Mr. Chesser is credited with two years of service for every one year of service earned under our pension plan, with such amount payable under our SERP.

If Mr. Marshall is terminated without cause, he will be paid a severance amount equal to the target payment under the annual incentive plan plus two times his annual base salary. Mr. Marshall is also credited with two years of service for every one year of service earned under our pension plan, with such amount payable under our SERP.

In August of 2008, the Company entered into an enhanced retirement and severance benefit agreement with Mr. Downey which provides a $700,000 lump sum payment upon his separation from service provided that (i) he remains until his 65th birthday and (ii) he remains in good standing with the restricted covenants set forth in his Change-in-Control Agreement. This agreement also provides for the payment of this lump sum if the Company terminates Mr. Downey's employment before age 65 (other than for Cause), or if Mr. Downey terminates employment before age 65 for Good Reason. Please see "Potential Payments Upon Termination or Change-in-Control," beginning on page 49 for a more detailed description of this agreement.

In December of 2008, the Company entered into an agreement with Mr. Easley that provided for a lump sum payment of $1,225,000 in connection with his resignation as of January 2, 2009, and certain releases and undertakings to assist the Company after resignation. This payment is included in the amount shown for Mr. Easley in column (i) of the Summary Compensation Table.

Our NEOs have also entered into Change in Control Severance Agreements. Please see "Potential Payments Upon Termination or Change-in-Control," beginning on page 49 for a description of these agreements and the other agreements described above.

Base salaries for our NEOs are set by the independent members of our Board, upon the recommendations of our Compensation and Development Committee. For 2008, the base salaries were: Mr. Chesser, $800,000; Mr. Downey, $490,000; Mr. Bassham, $375,000; Mr. Easley, $281,000; and Mr. Malik, $458,000. Mr. Marshall's 2008 base salary was initially set at $355,000, and was increased to $390,000 in August 2008 when he was promoted to Executive Vice President—Utility Operations. Our NEOs also participate in our health, welfare and benefit plans, our annual and long-term incentive plans, our pension and SERP plans (except for Mr. Malik), our non-qualified deferred compensation plan and receive certain other perquisites and personal benefits, such as car allowances, club

memberships, executive financial planning services, parking, spouse travel, personal use of company tickets, vacation buy-back, annual physicals, and matched charitable donations.

Awards

Restricted Stock

During 2008, our Board made one award of restricted stock to each of the NEOs, except Mr. Malik. The award of restricted stock is consistent with the Company's equity incentive compensation practices in 2008, and will vest on February 5, 2011. These awards were: Mr. Chesser, 11,442 shares; Mr. Downey, 5,373 shares; Mr. Bassham, 3,040 shares; Mr. Easley, 2,278 shares; and Mr. Marshall, 2,878 shares. Dividends paid on the restricted stock are reinvested in stock through our DRIP, and carry the same restrictions as the underlying awards.

Mr. Malik's outstanding restricted stock grants vested due to the sale of Strategic Energy. As of the sale date, 6,350 shares of restricted stock (including reinvested dividends) vested. Mr. Easley's outstanding restricted stock grants were forfeited on January 2, 2009, due to his resignation from the Company.

Performance Shares

The Board also granted performance shares for the period 2008-2010 to the NEOs, except Mr. Malik. Performance shares are payable in stock at the end of the performance period, depending on the achievement of specified measures. The performance share measure is our total shareholder return ("TSR") for the period compared against the EEI index of electric utilities. The number of shares awarded can range from 0% to 200% of the target amount, as adjusted for the change in fair market value of our shares between the time of grant and the payment date. Dividends will be paid in cash at the end of the period on the number of shares earned. There is no payout of performance shares, regardless of the TSR percentile ranking, if the Great Plains Energy TSR is negative for the applicable three-year period. The following table describes the potential payout percentages for the total shareholder return measure:

Total Shareholder Return Percentile Rank	Percentage Payout
81st and Above	200%
65th to 80th	150%
50th to 64th	100%
35th to 49th	50%
34th and Below	0%

Performance shares were awarded to our NEOs (except Mr. Malik) for the performance period of 2006-2008. As discussed in our CD&A, threshold performance was not achieved for the performance shares granted, thus no shares were paid.

Mr. Malik was awarded performance shares for the period 2007-2009. These performance shares vested on June 2, 2008, at the target level due to the sale of Strategic Energy. Mr. Malik received 10,325 shares of common stock and accrued cash dividends of $25,709.

Mr. Easley's outstanding performance share grants for the 2007-2009 and 2008-2010 performance periods were forfeited on January 2, 2009, due to his resignation from the Company.

Cash-Based Long-Term Incentives

As discussed in our CD&A, Strategic Energy's long-term incentives had a cash component. For the 2006-2008 long-term incentive grants, the cash component was 80%; for the 2007-2009 long-term incentive grants, the cash component was 50%.

Due to the sale of Strategic Energy in June 2008, Mr. Malik's 2006-2008 and 2007-2009 long-term cash incentives vested at target. Mr. Malik received $472,500 in cash under the 2006-2008 grants, and $330,000 in cash under the 2007-2009 grants.

In addition, Mr. Malik received $96,531, reflecting the cash amount of incentive compensation that would have been payable, at target performance, had customary grants been made in 2008 pursuant to Strategic Energy's long-term incentive compensation plan, prorated for the period of time between the beginning of 2008 and the closing date of the Strategic Energy sale.

Annual Incentives

Under the annual incentive plans for 2008, our NEOs (except for Mr. Malik) were eligible to receive up to 200% of a target amount set as a percentage of their respective base salaries, as follows: Mr. Chesser, 100%; Mr. Downey, 70%; Mr. Bassham, 50%; Mr. Easley, 50%; and Mr. Marshall, 54%. Mr. Marshall's target amount was increased from 50% to 60% in August 2008, when he was promoted to Executive Vice President—Utility Operations. This increase was prorated for the 2008 period. There were no payouts under the 2008 annual incentive program because the threshold core earnings level was not achieved. The table on page 29 summarizes the 2008 annual incentive plan, year-end results, and payout levels for Great Plains Energy and KCP&L.

Mr. Malik received $115,626 in cash, reflecting the amount of annual incentive compensation that would have been payable, at target performance, had customary grants been made in 2008 pursuant to Strategic Energy's annual incentive compensation plan, prorated for the period of time between the beginning of 2008 and the June 2, 2008, closing date of the Strategic Energy sale.

Salary and Bonus in Proportion to Total Compensation

As we discuss in our CD&A, one objective of our compensation program is to align management interests with those of our shareholders. The Compensation and Development Committee believes that a substantial portion of total compensation for its officers should be delivered in the form of equity-based incentives. In 2008, 75% of the long-term incentive grants to Messrs. Chesser, Downey, Bassham, Easley and Marshall were in the form of performance shares which, if earned after three years based on total return to shareholders, will be paid in Company stock. To mitigate potential volatility in payouts and provide a retention device, the remaining 25% of the long-term grant was in time-based restricted shares.

In 2008, we determined cash and equity incentive grants using the following proportions of base salary:

Name	Annual Cash Incentive at Target	Long-term Cash Incentive at Target	Long-term Equity Incentive at Target
Mr. Chesser	100%	—	150%
Mr. Downey	70%	—	115%
Mr. Bassham	50%	—	85%
Mr. Easley	50%	—	85%
Mr. Malik	60% (1)	150% (1)	0% (1)
Mr. Marshall	54% (2)	—	85%

(1) The percentages shown for Mr. Malik are target levels. Mr. Malik actually received payments reflecting the cash amount of incentive compensation that would have been payable, at target performance, had customary grants been made in 2008 pursuant to Strategic Energy's annual and long-term incentive compensation plans, prorated for the period of time between the beginning of 2008 and June 2, 2008, the closing date of the Strategic Energy sale.

(2) Mr. Marshall's target amount was increased from 50% to 60% in August 2008, when he was promoted to Executive Vice President—Utility Operations. This increase was prorated for the 2008 period, resulting in a 54% annual target amount.

The following table provides information regarding the outstanding equity awards held by each of the NEOs as of December 31, 2008. We have omitted from the table the columns titled "Number of securities underlying unexercised options, unexercisable" and "Equity incentive plan awards: Number of securities underlying unexercised unearned options," because there are no unexercisable options.

OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END

	Option Awards			Stock Awards			
Name (a)	Number of Securities Underlying Unexercised Option (#) Exercisable (b)	Option Exercise Price ($) (e)	Option Expiration Date (f)	Number of Shares of Stock That Have Not Vested (#) (1)(4) (g)	Market Value of Shares of Stock That Have Not Vested ($) (2)(4) (h)	Equity Incentive Plan Awards: Number of Shares That Have Not Vested (#) (3)(5) (i)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares That Have Not Vested ($) (2)(5) (j)
Mr. Chesser	—	—	—	122,918	2,376,005	29,923	578,412
Mr. Downey	20,000	25.55	2/6/11	—	—	—	—
	20,000	24.90	2/5/12	67,057	1,296,212	14,402	278,391
	5,249	27.73	8/5/13	—	—	—	—
Mr. Bassham	—	—	—	36,752	710,416	7,800	150,774
Mr. Easley	—	—	—	35,312	682,581	6,177	119,401
Mr. Malik (6)	—	—	—	—	—	—	—
Mr. Marshall	—	—	—	36,883	712,948	7,657	148,010

(1) Includes reinvested dividends on restricted stock that carry the same restrictions.

(2) The value of the shares is calculated by multiplying the number of shares by the closing market price ($19.33) as of December 31, 2008.

(3) The payment of performance shares is contingent upon our total shareholder return for the applicable performance periods compared against the EEI index of electric utilities. The threshold level numbers of shares are shown.

(4) Columns (g) and (h) reflect the time-based restricted stock grants that were not vested as of December 31, 2008. The following table provides the grant and vesting dates and number of unvested shares (including reinvested dividend shares) for each of the outstanding grants as of December 31, 2008.

Name	Grant Date	Vesting Date	Number of Shares of Restricted Stock That Have Not Vested
Mr. Chesser	May 6, 2008	February 5, 2011	12,080
	February 6, 2007	February 6, 2010	9,656
	February 6, 2007	February 6, 2010	45,404
	February 6, 2007	February 6, 2009	45,404
	February 7, 2006	February 7, 2009	10,374
Mr. Downey	May 6, 2008	February 5, 2011	5,673
	February 6, 2007	February 6, 2010	4,799
	February 6, 2007	February 6, 2010	25,540
	February 6, 2007	February 6, 2009	25,540
	February 7, 2006	February 7, 2009	5,505
Mr. Bassham	May 6, 2008	February 5, 2011	3,210
	February 6, 2007	February 6, 2010	2,453
	February 6, 2007	February 6, 2010	14,188
	February 6, 2007	February 6, 2009	14,189
	February 7, 2006	February 7, 2009	2,712
Mr. Easley	May 6, 2008	February 5, 2011	2,405
	February 6, 2007	February 6, 2010	2,089
	February 6, 2007	February 6, 2010	14,188
	February 6, 2007	February 6, 2009	14,189
	February 7, 2006	February 7, 2009	2,441
Mr. Marshall	May 6, 2008	February 5, 2011	3,039
	February 6, 2007	February 6, 2010	2,528
	February 6, 2007	February 6, 2010	14,188
	February 6, 2007	February 6, 2009	14,189
	February 7, 2006	February 7, 2009	2,939

All of Mr. Easley's outstanding restricted stock grants were forfeited as of January 2, 2009, due to his resignation from the Company.

(5) Columns (i) and (j) reflect the performance share awards, at threshold level, that were outstanding as of December 31, 2008. The following table provides the performance period and number of performance shares, at threshold, for each of the outstanding grants as of December 31, 2008.

Name	Performance Period	Number of Shares at Threshold
Mr. Chesser	2008-2010	17,163
	2007-2009	12,760
Mr. Downey	2008-2010	8,060
	2007-2009	6,342
Mr. Bassham	2008-2010	4,559
	2007-2009	3,241
Mr. Easley	2008-2010	3,417
	2007-2009	2,760
Mr. Marshall	2008-2010	4,316
	2007-2009	3,341

The threshold performance level for the 2006-2008 performance share grants was not achieved and no payouts were made under these grants. As a result, the grants were deemed to not be outstanding as of the end of the year. Mr. Easley's performance share grants for the 2007-2009 and 2008-2010 performance periods were forfeited as of January 2, 2009, due to his resignation from the Company.

(6) All of Mr. Malik's outstanding awards vested as of June 2, 2008, due to the sale of Strategic Energy.

OPTION EXERCISES AND STOCK VESTED

We have omitted the "Option award" columns from the following table, because none of our NEOs exercised options in 2008.

Name (a)	Number of Shares Acquired on Vesting (#) (d)	Value Realized on Vesting ($) (e)
Mr. Chesser	—	—
Mr. Downey	—	—
Mr. Bassham (1)	10,755	262,530
Mr. Easley (2)	11,802	331,872
Mr. Malik (3)	22,524	597,690
Mr. Marshall (4)	24,007	629,464

(1) Restricted stock of 9,083 shares, plus 1,672 DRIP shares vested on March 28, 2008. The value realized on vesting is the number of shares vested multiplied by the $24.41 closing price on March 28, 2008.

(2) Restricted stock of 10,000 shares, plus 1,802 DRIP shares vested on February 1, 2008. The value realized on vesting is the number of shares vested multiplied by the $28.12 closing price on February 1, 2008.

(3) Restricted stock of 4,956 shares, plus 893 DRIP shares, vested on February 1, 2008. The value realized on this vesting is the number of shares vested multiplied by the $28.12 closing price on February 1, 2008. Restricted stock of 5,585 shares, plus 765 DRIP shares, vested on June 2, 2008. On that same date, 10,325 shares of common stock were paid pursuant to a performance share grant for the performance period 2007-2009. The value realized on this vesting and payment is the number of shares vested and paid multiplied by the $25.98 closing price on June 2, 2008.

(4) Restricted stock of 20,275 shares, plus 3,732 DRIP shares vested on May 25, 2008. The value realized on vesting is the number of shares vested multiplied by the $26.22 closing price on the last business day before May 25, 2008.

The following discussion of the pension benefits for the NEOs reflects the terms of the Company's Management Pension Plan (the "Pension Plan"), SERP and Mr. Downey's supplemental retirement benefit agreement, and the present value of accumulated benefits as of December 31, 2008. We have omitted the column titled "Payments during the last fiscal year," because no payments were made in 2008.

PENSION BENEFITS

Name (a)	Plan Name (b)	Number of Years Credited Service (#) (c)	Present Value of Accumulated Benefit ($) (d)
Mr. Chesser (1)	Management Pension Plan	5.5	206,427
	Supplemental Executive Retirement Plan	11	1,437,913
Mr. Downey	Management Pension Plan	8.5	349,033
	Supplemental Executive Retirement Plan	8.5	538,930
	Supplemental Retirement Benefit	n/a	656,508
Mr. Bassham	Management Pension Plan	3	60,390
	Supplemental Executive Retirement Plan	3	42,852
Mr. Easley	Management Pension Plan	12.5	309,960
	Supplemental Executive Retirement Plan	12.5	159,870
Mr. Malik (2)	Supplemental Executive Retirement Plan	—	—
	Supplemental Executive Retirement Plan	—	—
Mr. Marshall (1)	Management Pension Plan	3	115,808
	Supplemental Executive Retirement Plan	6	307,983

(1) Messrs. Chesser and Marshall are credited with two years of service for every one year of service earned under our pension plan, with such amount payable under our SERP. Without this augmentation, Messrs. Chesser and Marshall would have accrued $615,743 and $84,197, respectively, under the SERP.

(2) Mr. Malik did not participate in either the Management Pension Plan or SERP.

Our NEOs, excluding Mr. Malik, participate in the Pension Plan and the SERP. In 2007, our management employees were given a one-time election to remain under the existing terms of the Pension Plan (the "Old Retirement Plan"), or to elect a new retirement program (the "New Retirement Plan") that included a slightly reduced benefit accrual formula under the Pension Plan (as well as a correspondingly reduced benefit accrual formula under the SERP for employees who participate in the SERP). Messrs. Chesser, Downey and Easley elected to remain under the Old Retirement Plan; Messrs. Bassham and Marshall elected the New Retirement Plan. We note the differences between the Old Retirement Plan and the New Retirement Plan below.

In the table above, the present value of the current accrued benefits under the Pension Plan and SERP with respect to each listed officer is based on the following assumptions: retirement at the earlier of age 62 or when the sum of age and years of service equal 85; full vesting of accumulated benefits; a discount rate of 6.1%; and use of the Pension Protection Act mortality and lump sum interest rate tables.

Pension Plan

The Pension Plan is a funded, tax-qualified, noncontributory defined benefit pension plan. Benefits under the Pension Plan are based on the employee's years of service and the average annual base salary over a specified period. Employees who elected to remain in the Old Retirement Plan and retire after they reach 65, or whose age and years of service add up to 85 (the "Rule of 85"), are entitled

under the Pension Plan to a total monthly annuity for the rest of their life (a "single life" annuity) equal to 50% of their average base monthly salary for the period of 36 consecutive months in which their earnings were highest. This reflects an accrual rate of 1.67% per year, capped at 30 years of service. The 50% annuity will be proportionately reduced if years of credited service are less than 30. Employees may also elect to retire and receive an unreduced benefit at age 62 with at least 5 years of credited service, in which case the benefit is based on their average base monthly salary for the period of 48 consecutive months in which their earnings were highest. If the benefit commences prior to age 62, it is reduced by 3% for each year that commencement precedes age 62. Employees may elect other annuity options, such as joint and survivor annuities or annuities with payments guaranteed for a period of time. The present value of each annuity option is the same; however, the monthly amounts payable under these options are less than the amount payable under the single life annuity option. Employees also may elect to receive their retirement benefits in a lump sum equal to the actuarial equivalent of a single life pension under the Pension Plan. Of our NEOs, only Mr. Downey and Mr. Chesser are eligible for early retirement benefits under the Pension Plan. Mr. Downey's early retirement benefit would be a monthly annuity equal to 14.2% of average base monthly salary during the period of 48 consecutive months in which earnings were highest. Mr. Chesser's early retirement benefit would be a monthly annuity equal to 8.7% of average base monthly salary during the period of 60 consecutive months in which earnings were highest. The compensation covered by the Pension Plan excludes any bonuses or other compensation. The amount of annual earnings that may be considered in calculating benefits under the Pension Plan is limited by law. For 2008, the annual limitation is $230,000.

Employees, such as Messrs. Bassham and Marshall, who elected the New Retirement Plan retain the benefit they accrued as of December 31, 2007, under the old formula with the old early retirement reductions. Participants in the New Retirement Plan also earn a benefit equal to 1.25% of their final average base earnings (averaged over 48 consecutive months), multiplied by the years of credited service earned after 2007. There is no cap on the years of credited service that can be earned. Employees under the New Retirement Plan may begin receiving their retirement benefit at age 55, but with a 5% per year reduction for each year before age 62. There is no Rule of 85 for post-2007 accrued benefits; however, participants may receive post-2007 accrued benefits (subject to the 5% per year reduction if they retire before age 62) when they start receiving pre-2008 accrued benefits. Participants in the New Retirement Plan may receive only their pre-2008 accrued benefits in a lump sum; post-2007 benefits must be taken in the form of one of the annuities described in the preceding paragraph.

SERP

The SERP is unfunded and provides out of general assets an amount substantially equal to the difference between the amount that would have been payable under the Pension Plan in the absence of tax laws limiting pension benefits and earnings that may be considered in calculating pension benefits, and the amount actually payable under the Plan. For participants under the Old Retirement Plan, it adds an additional ⅓% of highest average annual base salary for each year of credited service when the executive was eligible for supplemental benefits, up to a maximum of 30 years, and also makes up the difference (if any) between using a 36-month earnings averaging period and the averaging period used for the participant's benefits under the Pension Plan. Participants under the New Retirement Plan receive this same benefit; however, there is no cap on the years of credited service for benefits accrued after 2007. As mentioned, Messrs. Chesser and Marshall are credited with two years of service for every one year of service earned under our Pension Plan, with such amount payable under the SERP.

Supplemental Retirement Benefit

As discussed, Mr. Downey has an agreement with the Company providing for a supplemental lump sum retirement benefit of $700,000 if he retires after he reaches the age of 65. For the present value of this supplemental retirement benefit, we used the same assumptions as for the Pension Plan and SERP present values, except that we assumed retirement at age 65, because the agreement provides no retirement benefits if he retires before age 65.

NONQUALIFIED DEFERRED COMPENSATION

Name (a)	Executive Contribution in Last FY (1) ($) (b)	Registrant Contributions in Last FY (2) ($) (c)	Aggregate Earnings in Last FY (3) ($) (d)	Aggregate withdrawals/ distributions ($) (e)	Aggregate Balance at Last FYE (4) ($) (f)
Mr. Chesser	120,000	17,100	113,306	—	1,397,100
Mr. Downey	98,000	7,800	146,296	—	1,767,053
Mr. Bassham	12,000	4,350	13,573	—	166,750
Mr. Easley	50,000	1,530	35,911	—	445,723
Mr. Malik (5)	48,900	—	30,377	844,488	0
Mr. Marshall	177,500	5,325	91,180	—	1,159,864

(1) The entire amount shown in this column for each NEO is included in the amount shown for each NEO in the "Salary" column in the Summary Compensation Table.

(2) The entire amount shown in this column for each NEO is included in the amount shown for each NEO in the "All Other Compensation" column in the Summary Compensation Table.

(3) Only the above-market earnings are reported in the Summary Compensation Table. The above-market earnings were: Chesser, $43,560; Downey, $56,243; Bassham, $5,218; Easley, $13,806, Malik, $11,678; and Marshall, $35,054.

(4) The following amounts reported in this column were reported as compensation to the NEOs in the Summary Compensation Tables for previous years: Chesser—$155,092 (2007) and $558,841 (2006); Downey—$145,361 (2007) and $341,914 (2006); Bassham—$18,619 (2007) and $111,825 (2006); and Marshall—$196,358 (2007) and $378,838 (2006). Mr. Easley was not a NEO in either 2006 or 2007.

(5) The amounts shown for Mr. Malik are for the period ended June 2, 2008. On that date, Strategic Energy was sold, and Strategic Energy assumed the Company's obligations to Mr. Malik with respect to his deferred compensation amounts.

Our deferred compensation plan (the "DCP") is a nonqualified and unfunded plan. It allows selected employees, including our NEOs, to defer the receipt of compensation. There are different deferral provisions for those participants, such as Messrs. Chesser, Downey and Easley, who elected the Old Retirement Plan, and those for participants, such as Messrs. Bassham and Marshall, who elected the New Retirement Plan. Old Retirement Plan participants may defer up to 50% of base salary and 100% of awards under annual incentive plans. The DCP provides for a matching contribution in an amount equal to 50% of the first 6% of the base salary deferred by Old Retirement Plan participants, reduced by the amount of the matching contribution made for the year to the participant's account under our Employee Savings Plus Plan, as described in our CD&A. For New Retirement Plan participants, the DCP provides for a matching contribution in an amount equal to 100% of the first 6% of the base salary, bonus and incentive pay deferred, reduced by the amount of the matching contribution made for the year to the participant's account under the 401(k) Plan. An earnings rate is applied to the deferral amounts. This rate is determined annually by the Compensation and Development Committee and is generally based on the Company's weighted average cost of capital. The rate was set at 9.0% for 2008. Interest is compounded monthly on deferred amounts. Participants may elect prior to rendering services for which the compensation relates when deferred amounts are paid to them: either at a specified date, or upon separation from service. For participants who are "specified employees" under Internal Revenue Code Section 409A and who elect payment on

separation of service, amounts will be paid the first business day of the seventh calendar month following their separation from service.

POTENTIAL PAYMENTS UPON TERMINATION OR CHANGE-IN-CONTROL

Our NEOs are eligible to receive payments in connection with termination of their employment in certain situations, as explained in this section. The Company believes that severance protections, particularly in the context of a change in control transaction, can play a valuable role in attracting and retaining key executive officers. Accordingly, we provide such protections for our NEOs. The Compensation and Development Committee evaluates the level of severance benefits to provide a NEO on a case-by-case basis, and in general, considers these severance protections an important part of an executive's overall compensation and consistent with competitive practices. Payments made will vary, depending on the circumstances of termination, as we discuss below.

Payments under Change in Control Severance Agreements

We have Change in Control Severance Agreements ("Change in Control Agreements") with our NEOs, specifying the benefits payable in the event their employment is terminated within two years of a "Change in Control" or within a "protected period." Generally, a "Change in Control" occurs if:

- Any person (as defined by SEC regulations) becomes the beneficial owner of at least 35% of our outstanding voting securities;
- A change occurs in the majority of our Board; or
- A merger, consolidation, reorganization or similar transaction is consummated (unless our shareholders continue to hold at least 60% of the voting power of the surviving entity), or a liquidation, dissolution or a sale of substantially all of our assets occurs or is approved by our shareholders.

A "protected period" starts when:

- We enter into an agreement that, if consummated, would result in a Change in Control;
- We, or another person, publicly announces an intention to take or to consider taking actions which, if consummated, would constitute a Change in Control;
- Any person (as defined by SEC regulations) becomes the beneficial owner of 10% or more of our outstanding voting securities; or
- Our Board, or our shareholders, adopt a resolution approving any of the foregoing matters or approving a Change in Control.

The protected period ends when the Change in Control transaction is consummated, abandoned or terminated.

Mr. Malik's Change in Control Agreement also defined "Change in Control" to include the occurrence of these events at Strategic Energy. A "Change in Control" occurred for purposes of Mr. Malik's agreement on June 2, 2008, when Strategic Energy was sold. GMO's acquisition in July 2008 did not constitute a "Change in Control" under our Change in Control Agreements.

The Company also believes that the occurrence, or potential occurrence, of a change in control transaction will create uncertainty regarding the continued employment of our executive officers. This uncertainty results from the fact that many change in control transactions result in significant organizational changes, particularly at the senior executive level. We believe these change of control arrangements effectively create incentives for our executive team to build stockholder value and to obtain the highest value possible should we be acquired in the future, despite the risk of losing

employment and potentially not having the opportunity to otherwise vest in equity awards which are a significant component of each executive's compensation. These agreements are designed to encourage our NEOs to remain employed with the Company during an important time when their prospects for continued employment following the transaction could be uncertain. Because we believe that a termination by the executive for good reason may be conceptually the same as a termination by the Company without cause, and because we believe that in the context of a change in control, potential acquirors would otherwise have an incentive to constructively terminate the executive's employment to avoid paying severance, we believe it is appropriate to provide severance benefits in these circumstances.

Our change of control arrangements are "double trigger," meaning that acceleration of vesting is not awarded upon a change of control, unless the NEO's employment is terminated involuntarily (other than for cause) within 2 years of a Change in Control or protected period. We believe this structure strikes a balance between the incentives and the executive hiring and retention considerations described above, without providing these benefits to executives who continue to enjoy employment with an acquiring company in the event of a change of control transaction. We also believe this structure is more attractive to potential acquiring companies, who may place significant value on retaining members of our executive team and who may perceive this goal to be undermined if executives receive significant acceleration payments in connection with such a transaction and are no longer required to continue employment to earn the remainder of their equity awards.

The benefits under the Change in Control Agreements depend on the circumstances of termination. Generally, benefits are greater if the employee is not terminated for "Cause," or if the employee terminates employment for "Good Reason." "Cause" includes:

- A material misappropriation of any funds, confidential information or property;
- The conviction of, or the entering of, a guilty plea or plea of no contest with respect to a felony (or equivalent);
- Willful damage, willful misrepresentation, willful dishonesty, or other willful conduct that can reasonably be expected to have a material adverse effect on the Company; or
- Gross negligence or willful misconduct in performance of the employee's duties (after written notice and a reasonable period to remedy the occurrence).

An employee has "Good Reason" to terminate employment if:

- There is any material and adverse reduction or diminution in position, authority, duties or responsibilities below the level provided at any time during the 90-day period before the "protected period";
- There is any reduction in annual base salary after the start of the "protected period";
- There is any reduction in benefits below the level provided at any time during the 90-day period prior to the "protected period"; or
- The employee is required to be based at any office or location that is more than 70 miles from where the employee was based immediately before the start of the "protected period."

Our Change in Control Agreements also have covenants prohibiting the disclosure of confidential information and preventing the employee from participating or engaging in any business that, during the employee's employment, is in direct competition with the business of the Company within the United States (without prior written consent which, in the case of termination, will not be unreasonably withheld).

Change in Control with Termination of Employment

The following table sets forth our payment obligations under the Change in Control Agreements and, as applicable, existing awards of restricted stock and performance shares under the circumstances specified upon a termination of employment for our NEOs, except for Mr. Easley. Mr. Easley resigned from the Company as of January 2, 2009, and the payments actually made to Mr. Easley are discussed in the section titled "Retirement, Resignation, Death or Disability". The amounts shown in the table for each NEO, except Mr. Malik, is based on the assumptions that the termination took place on December 31, 2008, that all vacation was taken or paid during the year, and the NEO was paid for all salary earned through the date of termination. The table does not reflect amounts that would be payable to the NEOs for benefits or awards that already vested. The amounts shown in the table for Mr. Malik are the actual amounts paid, funded or guaranteed by Great Plains Energy under Mr. Malik's Change in Control Agreement and applicable awards.

Benefit	Mr. Chesser ($)	Mr. Downey ($)	Mr. Bassham ($)	Mr. Malik ($)	Mr. Marshall ($)
Two Times or Three Times Salary (1)	2,400,000	1,470,000	750,000	1,374,000	780,000
Two Times or Three Times Bonus (2)	1,266,984	725,559	243,766	925,392	267,404
Annualized Pro Rata Bonus (3)	422,328	241,853	121,883	36,920	133,702
Additional Retirement Benefits (4)	1,200,565	354,198	177,320	—	305,607
Supplemental Retirement and Severance (5)	—	700,000	—	—	—
Health and Welfare (6)	160,965	125,370	51,995	31,957	62,684
Performance Share Awards Vesting (7)	1,156,804	556,762	301,567	1,167,275	296,020
Performance Share Dividends Vesting (8)	127,461	62,179	32,875	25,709	32,931
Restricted Stock Vesting (9)	2,099,083	1,144,104	627,471	145,098	629,269
Restricted Stock and Option Dividends Vesting (10)	276,922	200,031	82,964	19,875	83,699
401(k) Employer Match Vesting	4,573	—	—	—	—
Deferred Compensation Plan Employer Match Vesting	12,417	—	4,806	—	14,541
Tax Gross-Up (11)	2,974,926	1,532,355	697,827	—	857,237
Total	12,103,028	7,112,411	3,074,474	3,726,226	3,463,094

(1) Messrs. Chesser, Downey and Malik receive three times their highest annual base salary, and Messrs. Bassham and Marshall receive two times their highest annual base salary, during the twelve-month period prior to the date of termination.

(2) Messrs. Chesser, Downey and Malik receive three times their highest average annualized annual incentive compensation awards during the five fiscal years (or, if less, the years they were employed by the company) immediately preceding the fiscal year in which the Change in Control occurs. Messrs. Bassham and Marshall receive two times their highest average annualized annual incentive compensation awards.

(3) The annualized pro rata bonus amount is at least equal to the average annualized incentive awards paid to the NEO during the last five fiscal years of the Company (or the number of years the NEO worked for the Company) immediately before the fiscal year in which the Change-in-Control occurs, pro rated for the number of days employed in that year. The amount shown for Mr. Malik is the difference between the pro rata bonus amount and the actual pro rata annual incentive compensation amount paid to him.

(4) The amounts reflect the present value of the benefit arising from additional years of service credited upon a Change in Control. Mr. Chesser is credited with two years for every one year of credited service under the Pension Plan, plus six additional years of credited service. Mr. Downey is credited for three additional years of service. Mr. Marshall is credited for two years for every one year of credited service under the Pension Plan, plus four additional years of credited service. Mr. Bassham is credited for two additional years of service. These benefits are paid through our SERP.

(5) Mr. Downey's supplemental retirement and severance benefit agreement provides for a $700,000 payment if the Company terminates his employment without Cause prior to age 65.

(6) The amounts include medical, accident, disability, and life insurance and are estimated based on our current COBRA premiums for medical coverage and indicative premiums for private insurance coverage for the individuals. The amount shown for Mr. Malik is the amount the Company contributed to Strategic Energy to reimburse that company for the cost of providing coverage to Mr. Malik.

(7) In the event of a "change in control" (which is generally consistent with the definition of a Change in Control in the Change in Control Agreements, except that the beneficial ownership threshold percentage is lower), our LTIP provides that all pre-May 2007 performance share grants (unless awarded less than six months prior to the change in control) are deemed to have been fully earned. Grants after April 2007 have an additional condition that the grantee's employment must have been terminated without Cause or for Good Reason. The amounts shown for each person (except for Mr. Malik) reflect the aggregate target number of performance shares for performance periods ending after 2008, valued at the $19.33 closing price of our stock on December 31, 2008. The threshold performance level for the 2006-2008 performance share grants was not achieved and no payouts were made under these grants. As a result, the grants were deemed to not be outstanding as of the end of 2008. Mr. Malik's amount reflects $899,031 in cash paid under the Strategic Energy long-term incentive plans, plus 10,325 shares paid at target on his outstanding performance share awards, valued at the $25.98 closing price on the June 2, 2008 payment date.

(8) Performance Share Dividends are the dividends accrued on the performance shares and payable in cash on the number of shares actually paid out.

(9) In the event of a "change in control" (which is generally consistent with the definition of a Change in Control in the Change in Control Agreements, except that the beneficial ownership threshold percentage is lower), our LTIP provides that all restrictions on pre-May 2007 restricted stock grants are removed. Grants after April 2007 have an additional condition that the grantee's employment must have been terminated without Cause or for Good Reason. The amounts shown for each person (except for Mr. Malik) reflect the aggregate number of restricted stock grants outstanding as of December 31, 2008, valued at the $19.33 closing price of our stock on that date. Mr. Malik's amount reflects the number of restricted stock grants outstanding as of June 2, 2008, the date of sale of Strategic Energy, valued at the $25.98 closing price on that date.

(10) Dividends on restricted stock awards are reinvested in Company stock, and carry the same restrictions. The amounts shown for each person reflects the number of shares of reinvested dividends, valued at the same closing price as the person's restricted stock grants described in footnote (9). The amount shown for Mr. Downey also reflects the payment of $47,923 of accrued dividends on certain of his stock option grants that are payable on a Change in Control.

(11) The Change in Control Agreements generally provide for an additional payment to cover excise taxes imposed by Section 4999 of the Internal Revenue Code ("Section 280G gross-up payments"). We have calculated these payments based on the estimated payments discussed above, as well as the acceleration of equity awards that are discussed in more detail below. In calculating these payments, we did not make any reductions for the value of reasonable compensation for pre-Change in Control period and post-Change in Control period service, such as the value attributed to non-compete provisions. In the event that payments are due under Change in Control Agreements, we would perform evaluations to determine the reductions attributable to these services. No Section 280G gross-up payment was required in Mr. Malik's case.

Change in Control without Termination of Employment

Upon a Change in Control, all restrictions on outstanding unvested restricted stock and unvested restricted stock options granted prior to the May 2007 amendments to our LTIP held by our NEOs would vest, and all outstanding performance share grants that were granted prior to May 2007 would be deemed to have been fully earned, even if the NEO continues employment throughout the protected period. The following table sets forth the value of the restricted stock and performance shares (using the December 31, 2008, closing price of our stock) plus accrued dividends payable under these pre-May 2007 grants to the indicated NEOs, assuming a Change in Control as of December 31, 2008.

Mr. Chesser	Mr. Downey	Mr. Bassham	Mr. Marshall
$2,720,507	$1,473,826	$795,207	$805,552

Mr. Malik is not included in this table, because all of his outstanding restricted stock and performance share grants vested as of June 2, 2008. Mr. Easley is not included in this table, because he resigned as of January 2, 2009, from the Company.

Mr. Downey holds stock options that are currently exercisable. He has limited stock appreciation rights on 45,249 option shares, which entitle him, in the event of a Change in Control, to receive cash in an amount equal to the difference between the fair market value, as of the date of the event, of the shares underlying the stock appreciation rights and the aggregate base or exercise price of these options. Of those option shares, 5,249 option shares also carry rights to accrued dividends upon option exercise or in the event of a Change in Control. No amount would have been paid on the limited stock appreciation rights if a Change in Control occurred on December 31, 2008, because the fair market value on that date was less than the exercise prices of these options. Mr. Downey would have been entitled to receive $47,923, less applicable withholding taxes, respecting the accrued dividends on the 5,249 option shares.

Retirement, Resignation, Termination, Death or Disability

Upon retirement or resignation, the NEO would receive all accrued and unpaid salary and benefits, including the retirement benefits discussed above. In the event of death or disability, the NEO (or his beneficiary) would receive group life insurance proceeds or group disability policy proceeds, as applicable. In addition, these events would have the following effects on outstanding LTIP awards: (i) if employment is terminated by either the Company or the NEO, all restricted stock and performance share awards would be forfeited; (ii) if the NEO retires, becomes disabled or dies, restricted stock and performance share awards granted before May 2007 would be prorated for service during the applicable periods, and all restricted stock and performance share awards granted after May 2007 would be forfeited, unless the Compensation and Development Committee takes other action in its sole discretion; (iii) if the NEO retires, outstanding options expire three months from the retirement date; (iv) if the NEO resigns or is discharged, outstanding options terminate; and (v) if the NEO becomes disabled or dies, outstanding options terminate twelve months after disability or death.

Mr. Malik had an employment agreement with Strategic Energy. As discussed above, no payments were made under that agreement in connection with the change in control of Strategic Energy or Mr. Malik's termination of employment.

Mr. Chesser's employment offer letters provide that if he is terminated without cause, he will receive three times annual salary and bonus (if terminated prior to age 63), or one-time salary and bonus (if terminated between age 63 and before age 65). If Mr. Chesser were terminated without cause as of December 31, 2008 (and assuming that the Change in Control Agreement was not applicable), he would have received $4,800,000 under this arrangement.

Mr. Marshall's employment offer letter provides that if he is terminated without cause, he will receive a severance amount equal to the target payment under the annual incentive plan plus two times his annual base salary. If Mr. Marshall were terminated without cause as of December 31, 2008 (and assuming that the Change in Control Agreement was not applicable), he would have received $990,600 under this arrangement.

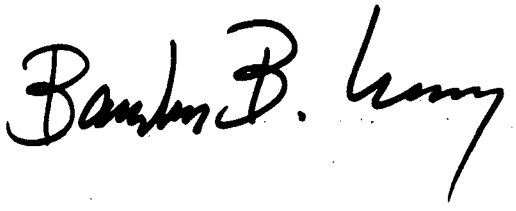
Mr. Downey's supplemental retirement and severance benefit agreement provides for a $700,000 lump sum payment if Mr. Downey retires after reaching age 65, or if the Company terminates Mr. Downey's employment before age 65 (other than for Cause), or if Mr. Downey terminates employment before age 65 for Good Reason. If Mr. Downey dies or becomes disabled prior to age 65, the lump sum will be payable, proportionately reduced based upon the amount of time he was actively employed by the Company during the period of time between August 5, 2008 (the date of the agreement) and Mr. Downey's 65th birthday. If Mr. Downey had died or become disabled as of December 31, 2008, a lump sum payment of $192,435.42 would have been payable under the agreement.

Mr. Easley's agreement with the Company in connection with his resignation provided for a lump sum cash payment of $1,225,000, which was made in January 2009. All of Mr. Easley's outstanding restricted stock and performance share grants were forfeited as of his January 2, 2009, resignation date.

OTHER BUSINESS

Great Plains Energy is not aware of any other matters that will be presented for shareholder action at the Annual Meeting. If other matters are properly introduced, the persons named in the accompanying proxy will vote the shares they represent according to their judgment.

By Order of the Board of Directors



Barbara B. Curry
Senior Vice President—Human Resources and Corporate Secretary

Kansas City, Missouri
March 25, 2009

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, 2008

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	

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 ☒ No ☐ Kansas City Power & Light Company Yes ☐ No ☒

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 ☒ Kansas City Power & Light Company 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.

Great Plains Energy Incorporated Yes ☒ No ☐ Kansas City Power & Light Company 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 the Form 10-K.

Great Plains Energy Incorporated ☐ Kansas City Power & Light Company ☒

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	☒	Accelerated filer	☐
	Non-accelerated filer	☐	Smaller reporting company	☐
Kansas City Power & Light Company	Large accelerated filer	☐	Accelerated filer	☐
	Non-accelerated filer	☒	Smaller reporting company	☐

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 ☒ Kansas City Power & Light Company Yes ☐ No ☒

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, 2008) was approximately $2,187,259,374. 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 23, 2009, Great Plains Energy Incorporated had 119,215,561 shares of common stock outstanding. On February 23, 2009, 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 2009 annual meeting 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.

Form 10-K

Form 10-K

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 KCP&L Greater Missouri Operations Company (GMO), does not relate to, and is not filed by, KCP&L. KCP&L makes no representation as to that information. Neither Great Plains Energy nor its other subsidiaries have any obligation in respect of KCP&L's debt securities and holders of such securities should not consider Great Plains Energy's or its other subsidiaries' financial resources or results of operations in making a decision with respect to KCP&L's debt securities. Similarly, KCP&L has no obligation in respect of securities of Great Plains Energy or its other subsidiaries.

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, 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 regional, national and international markets and their effects on sales, prices and costs, including, but not limited to, possible further deterioration in economic conditions and the timing and extent of any economic recovery; prices and availability of electricity in regional and national wholesale markets; market perception of the energy industry, Great Plains Energy, KCP&L and GMO; 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 and GMO 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 credit spreads and in availability and cost of capital and the effects on nuclear decommissioning trust and 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, but not limited to, weather-related damage and their effects on sales, prices and costs; cost, availability, quality and deliverability of fuel; ability to achieve generation planning goals and the occurrence and duration of planned and unplanned generation outages; delays in the anticipated in-service dates and cost increases of additional generating capacity and environmental projects; nuclear operations; workforce risks, including, but not limited to, retirement compensation and benefits costs; the ability to successfully integrate KCP&L and GMO operations and the timing and amount of resulting synergy savings; and other risks and uncertainties.

This list of factors is not all-inclusive because it is not possible to predict all factors. Part I Item 1A Risk Factors included in this report should be carefully read for further understanding of potential risks for each of Great Plains Energy and KCP&L. Other sections of this report and other periodic reports filed by each of Great Plains Energy and KCP&L 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
AFUDC	Allowance for Funds Used During Construction
Aquila or GMO	Aquila, Inc., a wholly owned subsidiary of Great Plains Energy as of July 14, 2008, which changed its name to KCP&L Greater Missouri Operations Company (GMO)
ARO	Asset Retirement Obligation
BART	Best available retrofit technology
Black Hills	Black Hills Corporation
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
Clean Air Act	Clean Air Act Amendments of 1990
CO_2	Carbon Dioxide
Collaboration Agreement	Agreement among KCP&L, the Sierra Club and the Concerned Citizens of Platte County
Company	Great Plains Energy Incorporated and its subsidiaries
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, as amended
FAC	Fuel Adjustment Clause
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
FGIC	Financial Guaranty Insurance Company
FIN	Financial Accounting Standards Board Interpretation
FSP	Financial Accounting Standards Board Staff Position
FSS	Forward Starting Swaps
GAAP	Generally Accepted Accounting Principles
Great Plains Energy	Great Plains Energy Incorporated and its subsidiaries
Holdings	DTI Holdings, Inc.
HSS	Home Service Solutions Inc., a wholly owned subsidiary of KLT, Inc.
IEC	Innovative Energy Consultants Inc., a former 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

Abbreviation or Acronym	Definition
KDHE	Kansas Department of Health and Environment
KLT Gas	KLT Gas Inc., a wholly owned subsidiary of KLT Inc.
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 former 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
MDNR	Missouri Department of Natural Resources
MGP	Manufactured gas plant
MISO	Midwest Independent Transmission System Operator, Inc.
MPS Merchant	MPS Merchant Services, Inc., a wholly owned subsidiary of GMO
MPSC	Public Service Commission of the State of Missouri
MW	Megawatt
MWh	Megawatt hour
NERC	North American Electric Reliability Corporation
NEIL	Nuclear Electric Insurance Limited
NO_x	Nitrogen Oxide
NPNS	Normal Purchases and Normal Sales
NRC	Nuclear Regulatory Commission
NYMEX	New York Mercantile Exchange
OCI	Other Comprehensive Income
PCB	Polychlorinated biphenyls
PPA	Pension Protection Act of 2006
PRB	Powder River Basin
PURPA	Public Utility Regulatory Policy Act
QCA	Quarterly Cost Adjustment
Receivables Company	Kansas City Power & Light Receivables Company, a wholly owned subsidiary of KCP&L
RTO	Regional Transmission Organization
SEC	Securities and Exchange Commission
Services	Great Plains Energy Services Incorporated, a wholly owned subsidiary of Great Plains Energy
SFAS	Statement of Financial Accounting Standards
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
SPP	Southwest Power Pool, Inc.
STB	Surface Transportation Board
Strategic Energy	Strategic Energy, L.L.C., a former subsidiary of KLT Energy Services
Syncora	Syncora Guarantee Inc. (formerly XL Capital Assurance, Inc.)
T - Lock	Treasury Lock
Union Pacific	Union Pacific Railroad Company
WCNOC	Wolf Creek Nuclear Operating Corporation
Westar	Westar Energy, Inc., a Kansas utility company
Wolf Creek	Wolf Creek Generating Station

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," and "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 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 INCORPORATED

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's wholly owned direct subsidiaries with operations or active subsidiaries are as follows:

- KCP&L is an integrated, regulated electric utility that provides electricity to customers primarily in the states of Missouri and Kansas. KCP&L has one wholly owned subsidiary, Kansas City Power & Light Receivables Company (Receivables Company).
- KCP&L Greater Missouri Operations Company (GMO) is an integrated, regulated electric utility that primarily provides electricity to customers in the state of Missouri. GMO also provides regulated steam service to certain customers in the St. Joseph, Missouri area. GMO wholly owns MPS Merchant Services, Inc. (MPS Merchant), which has certain long-term natural gas contracts remaining from its former non-regulated trading operations. Great Plains Energy acquired GMO on July 14, 2008. See Note 2 to the consolidated financial statements for additional information.
- Great Plains Energy Services Incorporated (Services) provides services at cost to Great Plains Energy and its subsidiaries. Effective December 16, 2008, Services employees were transferred to KCP&L. Services continues to obtain certain goods and third-party services for its affiliated companies.
- KLT Inc. is an intermediate holding company that primarily holds investments in affordable housing limited partnerships. KLT Inc. also wholly owns KLT Gas Inc. and Home Service Solutions Inc., which have no active operations. KLT Telecom Inc., a wholly owned subsidiary of KLT Inc., was dissolved in December 2008.

On June 2, 2008, Great Plains Energy completed the sale of Strategic Energy, L.L.C. (Strategic Energy). Strategic Energy is accounted for as discontinued operations for all periods presented. See Note 24 to the consolidated financial statements for additional information. Great Plains Energy indirectly owned 100% of Strategic Energy through its wholly owned subsidiaries KLT Inc. and Innovative Energy Consultants Inc. (IEC). IEC did not own or operate any assets other than its indirect interest in Strategic Energy. IEC was merged into KLT Inc. in July 2008.

Great Plains Energy's sole reportable business segment is electric utility. As presented herein for periods prior to 2008, Great Plains Energy's electric utility segment is the same as the previously reported KCP&L segment. For information regarding the revenues, income and assets attributable to the electric utility business segment, see Note 23 to the consolidated financial statements. Comparative financial information and discussion regarding the

electric utility business segment can be found in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A).

ELECTRIC UTILITY

The electric utility segment consists of KCP&L, a regulated utility, and, since the July 14, 2008, acquisition date, GMO's regulated utility operations which include its Missouri Public Service and St. Joseph Light & Power divisions. Electric utility serves over 820,000 customers located in western Missouri and eastern Kansas. Customers include approximately 722,000 residences, 96,000 commercial firms, and 2,800 industrials, municipalities and other electric utilities. Electric utility's retail revenues averaged approximately 83% of its total operating revenues over the last three years. Since the July 14, 2008, acquisition of GMO, electric utility's retail revenues averaged 85% of its total operating revenues. Wholesale firm power, bulk power sales and miscellaneous electric revenues accounted for the remainder of electric utility's revenues. Electric utility is significantly impacted by seasonality with approximately one-third of its retail revenues recorded in the third quarter. Electric utility's total electric revenues were 100% of Great Plains Energy's revenues over the last three years. Electric utility's net income accounted for approximately 120%, 130% and 109% of Great Plains Energy's income from continuing operations in 2008, 2007 and 2006, respectively.

Regulation

KCP&L and GMO are regulated by the Public Service Commission of the State of Missouri (MPSC), and KCP&L is also regulated by 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 and GMO are also subject to regulation by the Federal Energy Regulatory Commission (FERC), Southwest Power Pool, Inc. (SPP) and North American Electric Reliability Corporation (NERC). KCP&L has a 47% ownership interest in the Wolf Creek Generating Station (Wolf Creek), which 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 approximately 70% and 30%, respectively, of electric utility's total retail revenues since the July 14, 2008, acquisition of GMO. See Item 7. MD&A, Critical Accounting Policies section and Note 7 to the consolidated financial statements for additional information concerning regulatory matters.

In September 2008, KCP&L filed requests for annual rate increases with the MPSC and KCC and GMO filed requests for annual rate increases with the MPSC, with new rates expected to be effective in the third quarter of 2009. See Note 7 to the consolidated financial statements for additional 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, electric utility does not compete with others to supply and deliver electricity in its franchised service territory, although other sources of energy can provide alternatives to electric utility customers. If Missouri or Kansas were to pass and implement legislation authorizing or mandating retail choice, electric utility 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.

Electric utility 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, electric utility competes with owners of other generating stations and other power suppliers, principally utilities in its region, on the basis of availability and price. Electric utility's wholesale revenues averaged approximately 16% of its total revenues over the last three years.

Power Supply
Electric utility has over 6,000 MWs of generating capacity. The projected peak summer demand for 2009 is 5,511 MW. Electric utility expects to meet its projected capacity requirements for the years 2009 and 2010 with its generation assets, capacity purchases and demand-side management and efficiency programs. As part of KCP&L's Comprehensive Energy Plan, electric utility expects to have Iatan No. 2, a coal-fired plant, in service in 2010, which will add approximately 620 MW (electric utility's share) to electric utility's generating capacity.

KCP&L is a member of the SPP. SPP is a Regional Transmission Organization (RTO) mandated by FERC to ensure reliable supply of power, adequate transmission infrastructure and competitive wholesale prices of electricity. 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 electric utility's electric generation are coal and nuclear fuel. It is expected, with normal weather, that approximately 93% of 2009 generation will come from these sources with the remainder provided by wind, natural gas and oil. The actual 2008 and estimated 2009 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 2009	Actual 2008	Estimated 2009	Actual 2008
Coal	76 %	76 %	1.61	1.43
Nuclear	17	18	0.48	0.46
Coal and natural gas	3	1	7.29	4.72
Natural gas and oil	2	3	9.14	7.85
Wind	2	2	-	-
Total Generation	100 %	100 %	1.83	1.44

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

GMO's retail rates and KCP&L's retail rates in Kansas contain certain fuel recovery mechanisms. KCP&L's Missouri retail rates do not contain a fuel recovery mechanism. To the extent the price of fuel or purchased power increases significantly, or if electric utility's lower cost units do not meet anticipated availability levels, Great Plains Energy's net income may be adversely affected unless and until the increased cost could be reflected in KCP&L's Missouri retail rates. Additionally, GMO's retail rates and KCP&L's retail rates in Missouri reflect a set level of non-firm wholesale electric sales margin. KCP&L and GMO will not recover any shortfall in non-firm wholesale electric sales margin and for KCP&L, any amount of margin above the level reflected in Missouri retail rates will be returned to KCP&L Missouri retail customers in a future rate case.

Coal
During 2009, electric utility's generating units, including jointly owned units, are projected to burn approximately 15 million tons of coal. KCP&L and GMO have 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 almost all of the projected coal requirements for 2009 and approximately 60% for 2010, 40% for 2011 and 25% for each of 2012 and 2013. The remainder of the coal requirements will be fulfilled through additional contracts or spot market purchases. KCP&L and GMO have entered into coal contracts over time at higher average prices affecting coal costs for 2009 and beyond.

KCP&L and GMO have also entered into rail transportation contracts with various railroads to transport coal from the PRB to their generating units. The transportation services to be provided under these contracts will satisfy approximately 75% of the projected requirements for 2009 and approximately 65% for 2010. The majority of KCP&L's and GMO's rail transportation contracts expire in 2010. KCP&L and GMO will pay tariff rates after 2010, which are typically higher. Coal transportation costs are expected to increase in 2009 and beyond.

Nuclear Fuel

KCP&L owns 47% of Wolf Creek Nuclear Operating Corporation (WCNOC), the operating company for Wolf Creek, which is electric utility's 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 87% after that date through September 2018. 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. Management anticipates the cost of nuclear fuel to increase significantly in 2010, after which increases are expected to be moderate. Even with this anticipated increase, management expects nuclear fuel cost per MWh generated to remain less than the cost of generation from other fuel sources. See Note 6 to the consolidated financial statements for additional information regarding nuclear plant.

Natural Gas

At December 31, 2008, KCP&L had hedged approximately 31% and 3% of its 2009 and 2010, respectively, projected natural gas usage for generation requirements to serve retail load and firm MWh sales. At December 31, 2008, GMO had hedged approximately 65% and 4% of its 2009 and 2010, respectively, expected on-peak natural gas usage and natural gas equivalent purchased power.

Purchased Capacity and Power

KCP&L and GMO have distinct rate and dispatching areas. As a result, KCP&L and GMO do not joint-dispatch their respective generation, resulting in GMO purchasing capacity and power to meet its customers' needs. GMO has long-term purchased capacity and power agreements for approximately 235 MW. At times, KCP&L purchases power to meet its customers' needs when it does not have sufficient available generation or when the cost of purchased power is less than KCP&L's cost of generation or to satisfy firm power commitments. Management believes electric utility 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. Electric utility's purchased power, as a percent of MWh requirements, averaged approximately 15%, 7% and 2% for 2008, 2007 and 2006, respectively. Since the July 14, 2008, acquisition of GMO, electric utility's purchased power, as a percentage of MWh requirements, averaged approximately 19%.

Environmental Matters

See Note 16 to the consolidated financial statements for information regarding environmental matters.

KANSAS CITY POWER & LIGHT COMPANY

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 approximately 509,000 customers located in western Missouri and eastern Kansas. Customers include approximately 449,000 residences, 58,000 commercial firms, and 2,000 industrials, municipalities and other electric utilities. KCP&L's retail revenues averaged approximately 82% 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 KCP&L's revenues. KCP&L is significantly impacted by seasonality with approximately one-third of its retail revenues recorded in the third quarter.

GREAT PLAINS ENERGY AND KCP&L EMPLOYEES

At December 31, 2008, Great Plains Energy and KCP&L had 3,259 employees, including 1,935 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, 2013), with Local 1464, representing transmission and distribution workers (expires January 31, 2012), and with Local 412, representing power plant workers (expires February 28, 2010).

Executive 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 on January 1, 2010, unless otherwise determined by the Board of Directors. 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. Each executive officer holds the same position with GMO as he or she does with KCP&L.

Name	Age	Current Position(s)	Year First Assumed an Officer Position
Michael J. Chesser [a]	60	Chairman of the Board and Chief Executive Officer – Great Plains Energy and KCP&L	2003
William H. Downey [b]	64	President and Chief Operating Officer – Great Plains Energy and KCP&L	2000
Terry Bassham [c]	48	Executive Vice President - Finance and Strategic Development and Chief Financial Officer – Great Plains Energy and KCP&L	2005
Barbara B. Curry [d]	54	Senior Vice President – Human Resources and Corporate Secretary – Great Plains Energy and KCP&L	2005
Michael L. Deggendorf [e]	47	Senior Vice President – Delivery – KCP&L	2005
Scott H. Heidtbrink [f]	47	Senior Vice President - Supply – KCP&L	2008
John R. Marshall [g]	59	Executive Vice President – Utility Operations - KCP&L	2005
William G. Riggins [h]	50	General Counsel and Chief Legal Officer – Great Plains Energy and KCP&L	2000
Lori A. Wright [i]	46	Vice President and Controller – Great Plains Energy and KCP&L	2002

[a] Mr. Chesser was appointed Chief Executive Officer of KCP&L in 2008. Previously he was Chairman of the Board (2003-2008) of KCP&L.

[b] Mr. Downey was appointed President and Chief Operating Officer of KCP&L in 2008. Previously he was President and Chief Executive Officer (2003-2008) of KCP&L.

[c] Mr. Bassham was appointed Executive Vice President – Finance and Strategic Development and Chief Financial Officer of KCP&L in 2009. Previously, Mr. Bassham was Chief Financial Officer (2005-2008) of KCP&L. Prior to that he was Executive Vice President, Chief Financial and Administrative Officer (2001-2005) of El Paso Electric Company.

[d] Ms. Curry was appointed Senior Vice President – Human Resources and Corporate Secretary in 2008. Previously she was Senior Vice President – Corporate Services and Corporate Secretary of Great Plains Energy and Corporate Secretary (2005-2008) of KCP&L. Prior to that, she was Senior Vice President, Retail Operations (2003-2004) of TXU Corporation.

(e) Mr. Deggendorf was previously Vice President – Public Affairs of Great Plains Energy (2005-2008) and Senior Director, Energy Solutions (2002-2005) of KCP&L.

(f) Mr. Heidtbrink was previously Vice President – Power Generation & Energy Resources (2006-2008) and Vice President, Kansas/Colorado Gas (2002-2004) of GMO. In 2004 and 2005, he led GMO's Six Sigma deployment into its utility operations.

(g) Mr. Marshall was previously Senior Vice President – Delivery (2005-2008) of KCP&L. Prior to that, he was President of Coastal Partners, Inc., a strategy consulting company (2001-2005), and Senior Vice President, Customer Service (2002-2004) of Tennessee Valley Authority.

(h) Mr. Riggins was previously Vice President, Legal and Environmental Affairs and General Counsel (2005-2008) of KCP&L and General Counsel (2000-2005) of Great Plains Energy.

(i) Ms. Wright was previously Controller (2002-2008) of Great Plains Energy and KCP&L.

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 KCP&L could differ materially from historical results and the forward-looking statements contained in this report. 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. This information, as well as the other information included in this report and in the other documents filed with the SEC, should be carefully considered before making an investment in the securities of Great Plains Energy and KCP&L. Risk factors of KCP&L and GMO are also risk factors of Great Plains Energy.

Regulatory and Environmental Risks:

Complex utility and environmental regulation could adversely affect Great Plains Energy's and KCP&L's results of operations, financial position and cash flows.

KCP&L and GMO are subject to, or affected by, extensive federal and state utility regulation, including by the MPSC, KCC, FERC, NRC, SPP and NERC. They must also comply with environmental legislation and associated regulations. In the Company's business planning and management of operations, it must address the effects of existing and proposed regulation on its businesses and changes in the regulatory framework, including initiatives by federal and state legislatures, regional transmission organizations, utility regulators and taxing authorities. Failure of KCP&L or GMO 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 Great Plains Energy's and KCP&L's results of operations, financial position and cash flows.

The outcome of retail rate proceedings could have a material impact on the business and is largely outside the Company's control.

The rates that KCP&L and GMO are allowed to charge their customers are the single most important item influencing their results of operations, financial position and cash flows. These rates are subject to the determination, in large part, of governmental entities outside of KCP&L's and GMO's control, including the MPSC, KCC (for KCP&L) and FERC. KCP&L and GMO are also exposed to cost-recovery shortfalls due to the inherent lag in the rate-setting process, especially during periods of significant cost inflation, as utility rates in Missouri and Kansas are set on the basis of historical costs and are not subject to adjustment (other than for fuel and purchased power for KCP&L in Kansas and GMO) between rate cases.

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 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. In March 2007, KCP&L entered into a Collaboration Agreement with the Sierra Club and Concerned Citizens of Platte County that provides for increases in KCP&L's wind generation capacity and energy efficiency initiatives, reductions in certain emission permit levels at its Iatan and LaCygne generating stations, and projects to offset certain carbon dioxide emissions. The wind generation, energy efficiency and emission permit reductions are conditioned on regulatory approval.

A reduction or rejection by the MPSC or KCC of rate increase requests reflecting the costs of projects under the Comprehensive Energy Plan or Collaboration Agreement, or other costs and expenses, could lead to lowered credit ratings, reduced access to capital markets, increased financing costs, lower flexibility due to constrained financial resources and increased collateral security requirements, which could materially and adversely affect Great Plains Energy's and KCP&L's results of operations, financial position, and cash flows. In response to competitive, economic, political, legislative and regulatory pressures, KCP&L and GMO may be subject to rate moratoriums, rate refunds and 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 Great Plains Energy's and KCP&L's results of operations, financial position and cash flows.

Regulatory requirements regarding utility operations may increase costs and may expose KCP&L and GMO to compliance penalties.

The MPSC and KCC have the authority to implement utility operational standards and requirements, such as vegetation management standards, facilities inspection requirements and quality of service standards. KCP&L agreed to quality of service standards in Kansas in connection with the GMO acquisition. The costs of new or modified operational standards and requirements could have an adverse effect on Great Plains Energy's and KCP&L's results of operations, financial position and cash flows as a result of increased operations or maintenance and capital expenditures for new facilities or to repair or improve existing facilities. Failure to meet quality of service, operational or other standards and requirements could expose KCP&L or GMO to penalties or other adverse rate consequences.

The Company is subject to current and potential environmental laws and the incurrence of environmental liabilities, any or all of which may adversely affect the Company's business and financial results.
The Company is subject to regulation by federal, state and local authorities with regard to air quality and other environmental matters, through KCP&L's and GMO's operations. The generation, transmission and distribution of electricity produces and requires proper management and disposal of certain hazardous products and wastes, 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's and KCP&L's results of operations, financial position and cash flows.

There is also a risk that new environmental laws and regulations, and new judicial interpretations of environmental laws and regulations, could adversely affect KCP&L's and GMO's operations. In particular, various stakeholders, including legislators, regulators, shareholders and non-governmental organizations, as well as utilities and other companies in many business sectors, are considering ways to address climate change, including through the regulation of CO_2 and other greenhouse gas emissions and efforts to encourage or mandate the use of renewable resources, energy efficiency and demand response management. In November 2008, Missouri voters approved an initiative that requires at least 2% of electricity to come from renewable resources by 2011, increasing to 15% by 2021. The governor of Kansas supports mandatory renewable energy portfolio standards, and bills that would establish such standards have been introduced in the 2009 Kansas Legislature. The Kansas Department of Health and Environment (KDHE) has indicated that it intends to engage industries and stakeholders to establish goals and strategies for reducing CO_2 emissions. Additional federal and/or state legislation or regulation to release greenhouse gas emissions may be enacted in the near future. Further, pursuant to the Collaboration Agreement, KCP&L agreed to pursue a set of initiatives including energy efficiency, additional wind generation, lower emission permit levels at its Iatan and LaCygne stations and other initiatives designed to offset CO_2 emissions. KCP&L's current generation capacity is primarily coal-fired and is estimated to produce about one ton of CO_2 per MWh, or approximately 17 million tons per year. GMO's current generation capacity also is primarily coal-fired and is estimated to produce approximately 6 million tons of CO_2 per year. Requirements to reduce greenhouse gas emissions may cause KCP&L and GMO to incur significant costs relating to their ongoing operations (through additional environmental control equipment, retiring and replacing existing generation, or selecting more costly generation alternatives), to procure emission allowance credits, or due to the imposition of taxes, fees or other governmental charges as a result of such emissions. Rules issued by the Environmental Protection Agency (EPA) regarding emissions of mercury, nitrogen oxides and sulfur dioxides are also in a state of flux. Such rules have been overturned by the courts and remanded to the EPA to be revised consistent with the court orders. It is unclear what standards will be imposed in the future, when KCP&L and GMO may have to comply with any new standards or what costs may ultimately be required to comply with such standards.

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 associated uncertainty may materially affect the cost and timing of the environmental retrofit projects included in the Comprehensive Energy Plan, among other projects, and thus materially affect Great Plains Energy's and KCP&L's results of operations, financial position and cash flows.

Under current law, KCP&L and GMO are also generally responsible for any liabilities associated with the environmental condition of their properties, including properties that they have previously owned or operated, such as manufactured gas plants (MGP), regardless of whether they were responsible for the contamination or whether the liabilities arose before, during or after the time they owned or operated the properties. KCP&L and GMO may not be allowed by the MPSC or KCC to recover all of their costs for environmental expenditures through rates in the future. The incurrence of material environmental costs or liabilities, without related rate recovery, could have a material adverse effect on Great Plains Energy's or KCP&L's results of operations, financial position and cash flows. See the notes to the consolidated financial statements for additional information regarding environmental matters.

The Federal Clean Air Act requires companies to obtain permits and, if necessary, install control equipment to reduce emissions when making a major modification or a change in operation of an existing facility if either is expected to cause a significant net increase in regulated emissions. In 2004, the EPA notified Westar Energy, Inc. (Westar) that certain projects completed at the Jeffrey Energy Center violated certain New Source Review permitting requirements. GMO is an 8% owner of the facility, which is operated by Westar, and is generally responsible for its 8% share of the facility's operating costs and capital expenditures. On February 4, 2009, the Attorney General of the United States filed a complaint against Westar alleging that it violated the Clean Air Act and related federal and state regulations by making major modifications to the Jeffrey Energy Center beginning in 1994 without first obtaining appropriate permits authorizing this construction and without installing and operating best available control technology to control emissions. Resolution of this matter potentially could involve the installation and operation of new emission control systems at Jeffrey Energy Center, surrender of emission allowances, interruptions or shut-down of operations at the Jeffrey Energy Center, applications for new or modified permits, audits of Jeffrey Energy Center operations, actions to otherwise mitigate any resulting harm to public health and the environment, and assessment of a civil penalty of up to $37,500 per day for each violation. GMO's 8% portion of such costs could be significant. The ultimate outcome of these matters cannot presently be determined, nor can the liability that could potentially result from a negative outcome presently be reasonably estimated. There is no assurance these costs, if any, could be recovered in rates, and any failure to recover such costs could have a significant effect on Great Plains Energy's results of operations, financial position and cash flows.

In 2008, KCP&L received a subpoena from a federal grand jury seeking documents relating to capital projects at Iatan No. 1. KCP&L expects to complete the delivery of responsive documents by early March 2009. KCP&L believes that it is in compliance in all material respects with all relevant laws and regulations; however, the ultimate outcome of these grand jury activities or possible civil or administrative proceedings regarding capital projects at Iatan No. 1 and other coal units cannot presently be determined, nor can the liability that could potentially result from a negative outcome presently be reasonably estimated. There is no assurance these costs, if any, could be recovered in rates, and any failure to recover such costs could have a significant effect on Great Plains Energy's and KCP&L's results of operations, financial position and cash flows.

Due to all of the above, KCP&L's and GMO's projected capital and other expenditures for environmental compliance are subject to significant uncertainties, including the timing of implementation of any new or modified environmental requirements, the emissions limits imposed by such requirements and the types and costs of the compliance alternatives selected by KCP&L and GMO. As a result, costs to comply with environmental requirements cannot be estimated with certainty, and actual costs could be significantly higher than projections. Other new environmental laws and regulations affecting the operations of KCP&L and GMO may be adopted, and new interpretations of existing laws and regulations could be adopted or become applicable to KCP&L and GMO or their facilities, any of which may adversely affect Great Plains Energy's and KCP&L's business and substantially increase their environmental expenditures or liabilities in the future.

Financial Risks:

Financial market disruptions and declines in the credit ratings of Great Plains Energy, KCP&L or GMO may increase financing costs and/or limit access to the credit markets, which may adversely affect liquidity and results.

KCP&L's capital requirements are expected to be substantial over the next several years. The acquisition of GMO has further increased the Company's overall capital requirements, and the capital requirements of GMO over the next several years are expected to be substantial as it implements generation and environmental projects. The Company relies on access to short-term money markets, revolving credit facilities provided by financial institutions 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 bank-provided credit facilities for credit support, such as letters of credit, to support operations. The amount of credit support required for KCP&L and GMO operations varies with a number of factors, including the amount and price of wholesale power purchased or sold.

Great Plains Energy, KCP&L, GMO and certain of their securities are rated by Moody's Investors Service and Standard & Poor's. These ratings impact the companies' cost of funds and Great Plains Energy's ability to provide credit support for its subsidiaries. The interest rates on borrowings under KCP&L's revolving credit agreement and on a substantial portion of Great Plains Energy's and GMO's debt are subject to increase as their respective credit ratings decrease. The Company has agreed to not seek rate recovery of GMO interest costs in excess of equivalent investment-grade debt, and the MPSC approval of the GMO acquisition is conditioned on the requirement that any post-acquisition financial effects of a credit downgrade of Great Plains Energy, KCP&L or GMO occurring as a result of the acquisition would be borne by shareholders and not utility customers. The amount of collateral or other credit support required under power supply agreements is also dependent on credit ratings.

The capital and credit markets have been experiencing unprecedented levels of volatility and disruption. If current levels of market disruption and volatility continue or worsen, or if there is a decrease in Great Plains Energy's, KCP&L's or GMO's credit ratings, there can be no assurance that the companies would not experience an adverse effect on their access to capital and cost of funds, dilution resulting from equity issuances at reduced prices, increases in the amount of collateral or other credit support obligations required to be posted with contractual counterparties, increased nuclear decommissioning trust and pension and other post-retirement benefit plan funding requirements, issuance of secured rather than unsecured debt, rate case disallowance of KCP&L's or GMO's costs of capital, or reductions in Great Plains Energy's ability to provide credit support for its subsidiaries. Any of these results could adversely affect Great Plains Energy's and KCP&L's results of operations, financial position and cash flows. In addition, market disruption and volatility could have an adverse impact on Great Plains Energy's, KCP&L's or GMO's lenders, suppliers and other counterparties or on KCP&L's, GMO's, including MPS Merchant, customers, causing them to fail to meet their obligations.

A sustained decline in Great Plains Energy's stock price below book value may result in goodwill impairments that could adversely affect Great Plains Energy's results of operations and financial position, as well as credit facility covenants.
The GMO acquisition resulted in Great Plains Energy recording approximately $156 million in goodwill. Accounting rules require goodwill to be tested for impairment annually and when an event occurs indicating that it is possible that an impairment exists. The Company's annual impairment testing is conducted in September. Subsequent to September 2008, financial market disruptions and volatility have resulted in Great Plains Energy's stock trading at a price below carrying value. If the stock price continues to be below carrying value, the accounting rules may require Great Plains Energy to conduct another goodwill impairment test. There is no assurance that the results of this additional test will not require Great Plains Energy to recognize an impairment of goodwill. An impairment of GMO acquisition goodwill would reduce net income and may adversely affect Great Plains Energy's results of operations and financial position, and could result in a breach of the debt to total capitalization covenants in Great Plains Energy's and GMO's revolving credit agreements.

Great Plains Energy has guaranteed substantially all of the outstanding debt of GMO and payments under these guarantees may adversely affect Great Plains Energy's liquidity.
In connection with the GMO acquisition, Great Plains Energy issued guarantees covering substantially all of the outstanding debt of GMO and has guaranteed a $400 million revolving credit facility that was entered into by GMO subsequent to the acquisition. The guarantees were a factor in GMO receiving investment-grade ratings and the guarantees obligate Great Plains Energy directly to pay amounts owed by GMO to the holders of the guaranteed debt in the event GMO defaults on its payment obligations. Any guarantee payments could adversely affect Great Plains Energy's liquidity.

The inability of Great Plains Energy's subsidiaries to provide sufficient dividends to allow Great Plains Energy to pay dividends to its shareholders and meet its financial obligations would have an adverse effect.
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 and GMO. KCP&L has committed to state regulatory commissions to maintain a 35%

equity to total capitalization ratio, and Great Plains Energy, KCP&L and GMO have similar covenants in their revolving credit facilities. In addition, under federal law, KCP&L and GMO may pay dividends generally only out of retained earnings. 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 principally depends 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.

Market performance, increased retirements and changes in retirement plan regulations could significantly impact retirement plan funding requirements and associated cash needs and expenses.
Substantially all of KCP&L's employees participate in defined benefit and post-retirement plans. GMO's former employees in its Missouri utility operations and certain other operations have accrued benefits in GMO's defined benefit and post-retirement plans. If KCP&L employees retire when they become eligible for retirement through 2011, or if these plans experience adverse market returns on investments (as has been the case during the 2008 period), or if interest rates materially fall, KCP&L and GMO 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 Great Plains Energy's and KCP&L's results of operations, financial position and cash flows.

The Pension Protection Act of 2006 (PPA) 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 became 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 expense recognition related to pensions and other post-retirement benefits, which may result in accelerated expense.

The use of derivative contracts in the normal course of business could result in losses that could negatively impact Great Plains Energy's and KCP&L's results of operations, financial position and cash flows.
Great Plains Energy, KCP&L, GMO, including MPS Merchant, use derivative instruments, such as swaps, options, futures and forwards, to manage commodity and financial risks. Losses could be recognized as a result of volatility in the market values of these contracts, if a counterparty fails to perform, or if the underlying transactions which the derivative instruments are intended to hedge fail to materialize. In the absence of actively quoted market prices and pricing information from external sources, the valuation of these financial instruments can involve management's judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of these contracts.

As a service provider to GMO, KCP&L may have exposure to GMO's financial performance and operations.
GMO has no employees of its own. KCP&L employees operate and manage GMO's properties, and KCP&L charges GMO for the cost of these services. These arrangements may pose risks to KCP&L, including possible claims arising from actions of KCP&L employees in operating GMO's properties and providing other services to GMO. KCP&L's claims for reimbursement for services provided to GMO are unsecured and rank equally with other unsecured obligations of GMO. KCP&L's ability to be reimbursed for the costs incurred for the benefit of GMO depends on the financial ability of GMO to make such payments.

Customer and Weather-Related Risks:

Severe weather and changes in customer demand due to sustained financial market disruptions, downturns or sluggishness in the economy, weather conditions or otherwise may adversely affect Great Plains Energy's and KCP&L's results of operations, financial position and cash flows.
The results of operations, financial position and cash flows of Great Plains Energy and KCP&L can be materially affected by changes in weather and customer demand. KCP&L and GMO estimate customer demand based on historical trends to procure fuel and purchased power. Sustained downturns or sluggishness in the economy

generally affect the markets in which KCP&L and GMO operate. KCP&L's electricity sales volume declined in 2008 compared to 2007, and retail demand for KCP&L and GMO is expected to be lower in 2009 than it was in 2008 assuming normal weather conditions. If the current financial market disruptions or economic downturn continue or worsen, overall electricity sales volumes may further decline and/or bad debt expense may increase, which could materially affect Great Plains Energy's and KCP&L's results of operations, financial position and cash flows.

Weather conditions directly influence the demand for electricity and natural gas and affect the price of energy commodities. KCP&L and GMO are significantly impacted by seasonality, with approximately one-third of their retail electric revenues recorded in the third quarter. Unusually mild winter or summer weather can adversely affect sales. 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. Some of KCP&L's and GMO's stations use water from the Missouri River for cooling purposes. Low water and flow levels, which have been experienced in recent years, can increase maintenance costs at these stations and, if these levels were to get low enough, could cause modifications to plant operations.

Integration and Operational Risks:

Only a portion of the costs associated with the GMO acquisition will be recovered through utility rates, and the expected cost benefits of the GMO transaction may not be realized, which could adversely affect Great Plains Energy's results of operations, financial position and cash flows.
The MPSC order approving the GMO transaction provides that the transaction costs will not be recovered through utility rates, and that the Missouri jurisdictional portion of transition costs (estimated to be $33.1 million at December 31, 2008) will be eligible for recovery through utility rates only to the extent the costs are offset by benefits resulting from the acquisition. The KCC order approving the GMO transaction limited KCP&L's recovery of transition costs through Kansas rates to $10.0 million. At December 31, 2008, Great Plains Energy had $43.1 million of regulatory assets related to transition costs, which included $25.5 million at KCP&L and $17.6 million at GMO.

Great Plains Energy and KCP&L expect to achieve various benefits, including cost savings and operating efficiencies in connection with the acquisition. Approximately half of the total estimated cost savings over the first five years following the GMO acquisition are expected to come from reductions in GMO's corporate overhead and other costs that are not being recovered, and are not expected to be recovered, through utility rates. If these costs are not able to be eliminated as anticipated, Great Plains Energy's results of operations, financial position and cash flows could be negatively impacted.

The benefits of integrating KCP&L's and GMO's utility businesses may be less than expected, which could adversely affect the Company's regulatory treatment and results of operations, financial position and cash flows.
Great Plains Energy and KCP&L expect to achieve synergies through the ongoing integration of KCP&L and GMO utility operations. This integration poses significant challenges due to the size and complexity of each organization. The Company has dedicated substantial efforts and resources since the GMO acquisition was announced to plan for and implement an efficient and successful integration of utility operations. Great Plains Energy and KCP&L believe that the anticipated benefits will be achieved. However, there is no assurance that the utility operations integration will be completed successfully or in a timely manner, or result in the anticipated benefits. Failure to achieve the anticipated cost reductions or customer service levels could result in adverse regulatory actions and could negatively affect Great Plains Energy's and KCP&L's results of operations, financial position and cash flows.

Operations risks may adversely affect Great Plains Energy's and KCP&L's results of operations, financial position and cash flows.
The operation of KCP&L's and GMO's electric generation, transmission and distribution systems involves many risks, including breakdown or failure of equipment, processes and personnel performance; problems that delay or increase the cost of returning facilities to service after outages, operating limitations that may be imposed by equipment conditions, environmental, safety or other regulatory requirements; fuel supply or fuel transportation reductions or interruptions; transmission scheduling constraints; and catastrophic events such as fires, explosions, severe weather or other similar occurrences. An equipment outage or constraint can:

- in the case of generation equipment, directly affect operating costs, increase capital needs and costs, increase purchased power needs and costs and reduce wholesale sales opportunities;
- in the case of transmission equipment, affect operating costs, increase capital needs and costs, require changes in the source of generation and affect wholesale sales opportunities; and
- in the case of distribution systems, affect revenues and operating costs, increase capital needs and costs, and affect the ability to meet regulatory service metrics and customer expectations.

With the exception of Hawthorn No. 5, which was substantially rebuilt in 2001, all of KCP&L's coal-fired generating units and its nuclear generating unit were constructed prior to 1986. All of GMO's coal-fired generating units were constructed prior to 1984. The age of these generating units increases the risk of unplanned outages and higher maintenance expense. Training, preventive maintenance and other programs have been implemented, but there is no assurance that these programs will prevent or minimize future breakdowns or failures of KCP&L's or GMO's generation facilities.

KCP&L and GMO currently have general liability and property insurance in place to cover their facilities in amounts that management considers appropriate. These policies; however, do not cover KCP&L's or GMO's transmission or distribution systems, and the cost of repairing damage to these systems may adversely affect Great Plains Energy's or KCP&L's results of operations, financial position and cash flows. Such policies are subject to certain limits and deductibles and generally do not include business interruption coverage. Insurance coverage may not be available in the future at current costs or on commercially reasonable terms, and the insurance proceeds received for any loss of, or any damage to, any of KCP&L's or GMO's facilities may not be sufficient to restore the loss or damage.

These and other operating events may reduce Great Plains Energy's and KCP&L's revenues, increase their costs, or both, and may materially affect Great Plains Energy's and KCP&L's results of operations, financial position and cash flows.

The cost and schedule of construction projects may materially change and expected performance may not be achieved.
KCP&L's and GMO's businesses are capital intensive, and require significant capital investments to maintain existing facilities, for projected environmental projects and to add new facilities, including Iatan No. 2, an estimated 850 MW (of which electric utility's share is 620 MW) coal-fired generating plant. The acquisition of GMO by Great Plains Energy increases Great Plains Energy's exposure to the risks associated with the ongoing Iatan construction project. The risks of any construction project include the possibilities that actual costs may exceed current estimates, delays may occur in obtaining permits and materials, suppliers and contractors may not perform as required under their contracts, there may be inadequate availability or increased cost of qualified craft labor, the scope and timing of projects may change, and that other events beyond KCP&L's or GMO's control may occur that may materially affect the schedule, cost and performance of these projects.

The demand for additional environmental control equipment 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 for such projects, and there is a risk that such constraints may increase if new laws or regulations, including limitations on greenhouse gas emissions, are imposed.

These and other risks could materially increase the estimated costs of construction projects, delay the in-service dates of projects, adversely affect the performance of the projects, and/or require KCP&L or GMO to purchase additional electricity to supply their respective retail customers until the projects are completed. KCP&L and GMO are not permitted to start recovering the costs of these projects until they are completed and put into service. Thus, these risks may significantly affect Great Plains Energy's and KCP&L's results of operations, financial position and cash flows.

Failure of one or more generation plant co-owners to pay their share of construction, operations and maintenance costs could increase Great Plains Energy's and 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. GMO owns 18% of both Iatan units and 8% of Jeffrey Energy Center. 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. The Iatan No. 2 co-owners have provided financial assurances related to their respective construction cost obligations, but there is a risk that such assurances may not be sufficient in the event of a co-owner default. During the construction period, the Iatan No. 2 agreements provide 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 requirements, operations and maintenance costs of the non-defaulting owners. Occurrence of these or other events could materially increase Great Plains Energy's and KCP&L's costs and capital requirements.

An aging workforce and increasing demand for skilled craft labor poses operational and planning challenges.
Through 2012, approximately 22% of KCP&L employees (who manage both KCP&L and GMO operations) will be eligible to retire with full pension benefits. This is a general industry issue, which has increased the demand for and cost of skilled craft labor for both companies and contractors. KCP&L and GMO use contractors for a substantial portion of their construction and maintenance work. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to the new employees, or the future availability and cost of contract labor may adversely affect the ability to manage and operate Great Plains Energy's and KCP&L's businesses.

Commodity Price Risks:

Changes in commodity prices could have an adverse effect on Great Plains Energy's and KCP&L's results of operations, financial position and cash flows.
KCP&L and GMO engage in the wholesale and retail marketing of electricity and are exposed to risks associated with the price of electricity. KCP&L and GMO generate, purchase and sell electricity in the retail and wholesale markets. To the extent that exposure to the price of electricity is not successfully hedged, Great Plains Energy and KCP&L could experience losses associated with the changing market price for electricity.

Increases in fuel, fuel transportation and purchased power prices could have an adverse impact on Great Plains Energy's and KCP&L's costs.
KCP&L's Kansas retail rates contain an energy cost adjustment (ECA) mechanism. KCP&L's Missouri retail rates do not contain a similar provision. GMO's retail electric rates contain a fuel adjustment clause mechanism under which 95% of the difference between actual fuel and purchased power costs and the amount of fuel and purchased power costs provided in base rates is passed along to GMO's customers. GMO's steam rates contain a quarterly cost adjustment under which 80% of the difference between actual fuel costs and base fuel costs is passed along to GMO's steam customers. As a result, KCP&L and GMO are exposed to varying degrees of risk from changes in the market prices of coal, natural gas, nuclear fuel

and purchased power. Changes in KCP&L's or GMO's fuel mix due to electricity demand, plant availability, transportation issues, fuel prices, fuel availability and other factors can also adversely affect KCP&L's or GMO's fuel and purchased power costs.

KCP&L and GMO do not hedge their respective entire exposure from fuel and transportation price volatility. Forward prices for coal have increased, principally due to international demand, and management expects prices will continue to increase. The majority of KCP&L's and GMO's rail transportation contracts expire in 2010. KCP&L and GMO will pay tariff rates after 2010, which are typically higher. Management also expects the cost of nuclear fuel to increase significantly in 2010. Consequently, Great Plains Energy's and KCP&L's results of operations, financial position and cash flows may be materially impacted by changes in these prices until increased costs are recovered in Missouri retail rates.

Wholesale electricity sales affect revenues, creating earnings volatility.
The levels of KCP&L and GMO wholesale sales depend on the wholesale market price, transmission availability and the availability of generation for wholesale sales, among other factors. A substantial portion of wholesale sales are made in the spot market, and thus KCP&L and GMO have immediate exposure to wholesale price changes. Wholesale power prices can be volatile and generally increase in times of high regional demand and high natural gas prices. While an allocated portion of wholesale sales are reflected in KCP&L's Kansas ECA, GMO's and KCP&L's Missouri rates are set on an estimated amount of wholesale sales. KCP&L and GMO will not recover any shortfall in non-firm wholesale electric sales margin and for KCP&L, any amount above the level reflected in Missouri retail rates will be returned to Missouri retail customers in a future rate case. Declines in wholesale market price or availability of generation or transmission constraints in the wholesale markets could reduce KCP&L's and GMO's wholesale sales. These events could adversely affect Great Plains Energy's and KCP&L's results of operations, financial position and cash flows.

KCP&L is exposed to risks associated with the ownership and operation of a nuclear generating unit, which could result in an adverse effect on Great Plains Energy's and KCP&L's business and financial results.
KCP&L owns 47% 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. 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, financial position and cash flows 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 projected 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. Any such risks could adversely affect Great Plains Energy's and KCP&L's results of operations, financial position and cash flows.

Litigation Risks:

The outcome of legal proceedings cannot be predicted. An adverse finding could have a material adverse effect on Great Plains Energy's and KCP&L's financial condition.
Great Plains Energy, KCP&L and GMO are party to various material litigation and regulatory matters arising out of their business operations. The ultimate outcome of these matters cannot presently be determined, nor, in many cases, can the liability that could potentially result from a negative outcome in each case presently be reasonably estimated. The liability that Great Plains Energy, KCP&L and GMO may ultimately incur with respect to any of these cases in the event of a negative outcome may be in excess of amounts currently reserved and insured against with respect to such matters and, as a result, these matters may have a material adverse effect on Great Plains Energy's and KCP&L's results of operations, financial position and cash flows.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Electric Utility Generation Resources

	Unit	Year Completed	Estimated 2009 MW Capacity	Primary Fuel
Base Load	Wolf Creek	1985	545 [a]	Nuclear
	Iatan No. 1	1980	494 [a]	Coal
	LaCygne No. 2	1977	341 [a]	Coal
	LaCygne No. 1	1973	368 [a]	Coal
	Hawthorn No. 5 [b]	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	2003	308	Natural Gas
	Osawatomie	2003	76	Natural Gas
	Hawthorn No. 9	2000	130	Natural Gas
	Hawthorn No. 8	2000	76	Natural Gas
	Hawthorn No. 7	2000	75	Natural Gas
	Hawthorn No. 6	1997	136	Natural Gas
	Northeast Black Start Unit	1985	2	Oil
	Northeast Nos. 17 and 18	1977	109	Oil
	Northeast Nos. 13 and 14	1976	106	Oil
	Northeast Nos. 15 and 16	1975	99	Oil
	Northeast Nos. 11 and 12	1972	100	Oil
Wind	Spearville Wind Energy Facility [c]	2006	15	Wind
Total KCP&L			4,053	
Base Load	Iatan No. 1	1980	127 [a]	Coal
	Jeffrey Energy Center Nos. 1, 2 and 3	1978, 1980, 1983	174 [a]	Coal
	Sibley Nos. 1, 2 and 3	1960, 1962, 1969	474	Coal
	Lake Road Nos. 2 and 4	1957, 1967	126	Coal and Natural Gas
Peak Load	South Harper Nos. 1, 2 and 3	2005	315	Natural Gas
	Crossroads Energy Center	2002	300	Natural Gas
	Ralph Green No. 3	1981	71	Natural Gas
	Greenwood Nos. 1, 2, 3 and 4	1975-1979	253	Natural Gas/Oil
	Lake Road No. 5	1974	61	Natural Gas/Oil
	Lake Road Nos. 1 and 3	1951, 1962	33	Natural Gas/Oil
	Lake Road Nos. 6 and 7	1989, 1990	43	Oil
	Nevada	1974	21	Oil
Total GMO			1,998	
Total Great Plains Energy			6,051	

[a] Share of a jointly owned unit.

[b] 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.

[c] The 100.5 MW Spearville Wind Energy Facility's accredited capacity is 15 MW pursuant to SPP reliability standards.

KCP&L owns 50% of LaCygne Nos. 1 and 2, 70% of Iatan No. 1 and 47% of Wolf Creek. GMO owns 18% of Iatan No. 1 and 8% of Jeffrey Energy Center Nos. 1, 2 and 3. See Note 7 to the consolidated financial statements for information regarding KCP&L's Comprehensive Energy Plan and the construction of new generation capacity.

Electric Utility Transmission and Distribution Resources
Electric utility's electric transmission system interconnects with systems of other utilities for reliability and to permit wholesale transactions with other electricity suppliers. Electric utility has over 3,000 miles of transmission lines, approximately 17,000 miles of overhead distribution lines and over 7,000 miles of underground distribution lines in Missouri and Kansas. Electric utility has all the franchises necessary to sell electricity within its retail service territory. Electric utility's transmission and distribution systems are continuously monitored for adequacy to meet customer needs. Management believes the current systems are adequate to serve customers.

Electric Utility General
Electric utility'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 and the Crossroads Energy Center, which is contractually controlled. Certain other facilities are located on premises held under leases, permits or easements. Electric utility's 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 consist principally of electric generating stations, electric transmission and distribution lines and systems, and buildings (subject to exceptions, reservations and releases), are subject to a General Mortgage Indenture and Deed of Trust dated as of December 1, 1986. Mortgage bonds totaling $158.8 million, securing Environmental Improvement Revenue Refunding (EIRR) bonds, were outstanding at December 31, 2008.

Substantially all of the fixed property and franchises of GMO's St. Joseph Light & Power division is subject to a General Mortgage Indenture and Deed of Trust dated as of April 1, 1946. Mortgage bonds totaling $14.6 million were outstanding at December 31, 2008.

ITEM 3. LEGAL PROCEEDINGS

Other Proceedings
The companies are parties to various lawsuits and regulatory proceedings in the ordinary course of their respective businesses. For information regarding material lawsuits and proceedings, see Notes 2, 7, 16 and 17 to the consolidated financial statements. Such descriptions 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, 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 23, 2009, Great Plains Energy's common stock was held by 30,151 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 [a]				Common Stock Dividends Declared		
	2008		2007				
Quarter	High	Low	High	Low	2009	2008	2007
First	$ 28.85	$ 24.35	$ 32.67	$ 30.42	$ 0.2075 [b]	$ 0.415	$ 0.415
Second	26.76	24.67	33.18	28.82		0.415	0.415
Third	26.20	21.92	29.94	26.99		0.415	0.415
Fourth	22.43	17.09	30.45	28.32		0.415	0.415

[a] Based on closing stock prices.

[b] Declared February 10, 2009, and payable March 20, 2009, to shareholders of record as of February 27, 2009.

Regulatory Restrictions

Under stipulations with the MPSC and KCC, Great Plains Energy has committed to maintain consolidated common equity of not less than 30% of total capitalization.

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 Plans

Great Plains Energy'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, director shares, director deferred share units and performance shares to directors, officers and other employees of the Company and KCP&L.

Effective with the July 14, 2008, acquisition of GMO, Great Plains Energy assumed GMO's equity compensation plans. Stock options outstanding under those plans at the time of acquisition were converted into Great Plains Energy stock options. Great Plains Energy does not intend to issue any new grants or awards under the assumed plans.

The following table provides information, as of December 31, 2008, 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. 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			
Great Plains Energy Long-Term Incentive Plan	423,983 (1)	$ 25.52 (2)	3,284,689
GMO incentive plans (stock options)	411,357	89.55	416,146
Equity compensation plans not approved by security holders	-	-	-
Total	835,340	$ 76.10	3,700,835

(1) Includes 314,511 performance shares at target performance levels and options for 109,472 shares of Great Plains Energy common stock outstanding at December 31, 2008.

(2) The 314,511 performance shares have no exercise price and therefore are not reflected in the weighted average exercise price.

Purchases of equity securities
There were no purchases by Great Plains Energy of its equity securities during the fourth quarter of 2008.

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% of total capitalization.

Equity Compensation Plan
KCP&L does not have an equity compensation plan; however, KCP&L officers and certain employees participate in Great Plains Energy's Long-Term Incentive Plan. The GMO incentive plans that were assumed by Great Plains Energy upon the acquisition include stock options held by certain KCP&L employees.

ITEM 6. SELECTED FINANCIAL DATA

Year Ended December 31	2008	2007	2006	2005	2004
Great Plains Energy [a]	(dollars in millions except per share amounts)				
Operating revenues	$ 1,670	$ 1,293	$ 1,140	$ 1,131	$ 1,092
Income from continuing operations [b]	$ 120	$ 121	$ 137	$ 135	$ 132
Net income	$ 155	$ 159	$ 128	$ 162	$ 183
Basic earnings per common share from continuing operations	$ 1.16	$ 1.41	$ 1.74	$ 1.79	$ 1.81
Basic earnings per common share	$ 1.51	$ 1.86	$ 1.62	$ 2.15	$ 2.51
Diluted earnings per common share from continuing operations	$ 1.16	$ 1.40	$ 1.73	$ 1.79	$ 1.81
Diluted earnings per common share	$ 1.51	$ 1.85	$ 1.61	$ 2.15	$ 2.51
Total assets at year end	$ 7,869	$ 4,832	$ 4,359	$ 3,842	$ 3,796
Total redeemable preferred stock, mandatorily redeemable preferred securities and long-term debt (including current maturities)	$ 2,627	$ 1,103	$ 1,142	$ 1,143	$ 1,296
Cash dividends per common share	$ 1.66	$ 1.66	$ 1.66	$ 1.66	$ 1.66
SEC ratio of earnings to fixed charges	2.26	2.53	3.50	3.09	2.77
KCP&L					
Operating revenues	$ 1,343	$ 1,293	$ 1,140	$ 1,131	$ 1,092
Net income	$ 125	$ 157	$ 149	$ 144	$ 145
Total assets at year end	$ 5,229	$ 4,292	$ 3,859	$ 3,340	$ 3,335
Total redeemable preferred stock, mandatorily redeemable preferred securities and long-term debt (including current maturities)	$ 1,377	$ 1,003	$ 977	$ 976	$ 1,126
SEC ratio of earnings to fixed charges	2.87	3.53	4.11	3.87	3.37

(a) Great Plains Energy's results include GMO only from the July 14, 2008, acquisition date.

(b) This amount is before income (loss) from discontinued operations, net of income taxes, of $35.0 million, $38.3 million, $(9.1) million, $27.2 million and $50.3 million in 2008 through 2004, respectively.

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

GREAT PLAINS ENERGY INCORPORATED

EXECUTIVE SUMMARY

Description of Business

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 are KCP&L, GMO, KLT Inc. and Services. Great Plains Energy acquired GMO on July 14, 2008. Great Plains Energy's sole reportable business segment is electric utility for the periods presented. As presented herein, for periods prior to 2008, Great Plains Energy's electric utility segment is the same as the previously reported KCP&L segment.

Electric utility consists of KCP&L, a regulated utility, and GMO's regulated utility operations, which include its Missouri Public Service and St. Joseph Light & Power divisions. Electric utility has over 6,000 MWs of generating capacity and engages in the generation, transmission, distribution and sale of electricity to over 820,000 customers in the states of Missouri and Kansas. Electric utility's retail electricity rates are below the national average of investor-owned utilities. KCP&L's nuclear unit, Wolf Creek, accounts for approximately 15% of electric utility's base load capacity. In November 2008, the NRC approved WCNOC's application for a new operating license for Wolf Creek, extending its operating period from 2025 to 2045.

2008 Earnings Overview

Great Plains Energy's 2008 earnings were $152.9 million, or $1.51 per share, including income of $35.0 million from the discontinued operations of Strategic Energy and income of $12.5 million from GMO after its acquisition. For 2007, earnings were $157.6 million, or $1.85 per diluted share, including income of $38.3 million from the discontinued operations of Strategic Energy. Earnings in 2008 were favorably impacted by the acquisition of GMO, new retail rates at KCP&L and an increase in Allowance for Funds Used During Construction (AFUDC). These favorable impacts were more than offset by mild summer weather, a decrease in wholesale sales, and increased fuel, purchased power and operating expenses at KCP&L.

Strategic Focus

In 2008, Great Plains Energy refocused the company on its core regulated utility business. Great Plains Energy sold Strategic Energy, its major non-regulated business, acquired GMO, continued to make progress on the Comprehensive Energy Plan and filed requests for retail rate increases. These items are described in more detail as follows:

- **Sale of Strategic Energy – Discontinued Operations**
  In April 2008, the Board of Directors approved management's recommendation to sell Strategic Energy and Great Plains Energy entered into an agreement with Direct Energy Services, LLC (Direct Energy), a subsidiary of Centrica plc, under which Direct Energy acquired all of Great Plains Energy's interest in Strategic Energy. On June 2, 2008, Great Plains Energy completed the sale of Strategic Energy. Strategic Energy is reported as discontinued operations for the periods presented. See Note 24 to the consolidated financial statements for additional information.

- **GMO Acquisition**
  On July 14, 2008, Great Plains Energy closed its acquisition of GMO. On October 17, 2008, GMO changed its name from Aquila, Inc. to KCP&L Greater Missouri Operations Company. Prior GMO shareholders received $1.80 in cash plus 0.0856 of a share of Great Plains Energy common stock for each share of GMO common stock. The total purchase price of the acquisition was approximately $1.7 billion. Immediately prior to Great Plains Energy's acquisition of GMO, Black Hills Corporation (Black Hills) acquired GMO's electric utility assets in Colorado and its gas utility assets in Colorado, Kansas, Nebraska and Iowa. See Note 2 to the consolidated financial statements for additional information.

- **Comprehensive Energy Plan – Iatan No. 1 environmental and Iatan No. 2**
  - In the first quarter of 2009, KCP&L completed construction of the Iatan No. 1 environmental project and Iatan common facilities. KCP&L's share of the total projected cost excluding AFUDC is in the table below and includes KCP&L's 70% share of costs directly associated with Iatan No. 1 and KCP&L's 61% share of estimated costs of Iatan common facilities that will be used by both Iatan No. 1 and Iatan No. 2. The vast majority of the common facilities costs were previously included in the Iatan No. 2 cost estimates disclosed in the Company's quarterly reports on Form 10-Q during 2008. Great Plains Energy's total share of Iatan No. 1 is 88%, which consists of KCP&L's 70% share and GMO's 18% share. Great Plains Energy's total share of Iatan common facilities is 79%, which consists of KCP&L's 61% share and GMO's 18% share. Great Plains Energy's share of the total projected cost excluding AFUDC of the Iatan No. 1 environmental project and Iatan common facilities is in the table below.

  - Iatan No. 1 has been off-line for a scheduled outage since mid-October 2008 for a unit overhaul and to tie in the environmental equipment. Iatan No. 1 was originally scheduled to be back on-line in February 2009, but, during start-up, a high level of vibration was experienced. Repairs to the turbine could delay the in-service date of Iatan No. 1, by up to two months. Management believes that a delay of that duration could still be accommodated in the current KCP&L and GMO rate cases; however, there could be a corresponding delay in the effective date of the MPSC rate orders from the current August 5, 2009, date. Management is unable to predict the length of such a delay, if any.

  - KCP&L's approximate 55% share of the total projected cost of Iatan No. 2 excluding AFUDC is in the table below. The reduction in the range from the previously disclosed Iatan No. 2 cost estimates reflects removal of costs for common facilities discussed above. These costs were previously included in the Iatan No. 2 cost estimates disclosed in the Company's quarterly reports on Form 10-Q during 2008. Great Plains Energy's total share of Iatan No. 2 is 73%, which consists of KCP&L's 55% share and GMO's 18% share. Great Plains Energy's 73% share of the total projected cost excluding AFUDC of Iatan No. 2 is in the table below. The anticipated in-service date for Iatan No. 2 is the summer of 2010.

KCP&L

	Current Estimate Range	Previous Estimate Range	Change
		(millions)	
Iatan No. 1 (70% share)	$ 242 - $ 262	$ 330 - $ 350	$ (88) - $ (88)
Iatan No. 2 (55% share)	847 - 904	994 - 1,051	(147) - (147)
Iatan Common (61% share)	235 - 235	- - -	235 - 235
Total	$ 1,324 - $ 1,401	$ 1,324 - $ 1,401	$ - - $ -

Great Plains Energy

	Current Estimate Range	Previous Estimate Range	Change
		(millions)	
Iatan No. 1 (88% share)	$ 307 - $ 332	$ 415 - $ 440	$ (108) - $ (108)
Iatan No. 2 (73% share)	1,125 - 1,201	1,321 - 1,397	(196) - (196)
Iatan Common (79% share)	304 - 304	- - -	304 - 304
Total	$ 1,736 - $ 1,837	$ 1,736 - $ 1,837	$ - - $ -

- **Regulatory Proceedings**
  KCP&L filed requests for annual retail rate increases with the MPSC and KCC in the third quarter of 2008 to include its interest in the Iatan No. 1 environmental project in rate base and to recover overall increased costs of service. GMO filed requests for annual retail rate increases with the MPSC in the third quarter of 2008 to include its interest in the Iatan No. 1 environmental project and other capital additions in rate base and to recover overall increased costs of service. Any authorized changes to retail rates are expected to be effective in the third quarter of 2009. The following table details the rate increases requested by both KCP&L and GMO by jurisdiction.

		Annual Revenue Increase				
Rate Jurisdiction [a]	File Date	Traditional [b]	Additional Amortization	Total [c]	Return on Equity	Rate-making Equity Ratio
			(millions)			
GMO (MPS)	9/5/2008	$ 66.0	$ -	$ 66.0	10.75%	53.82%
GMO (L&P)	9/5/2008	17.1	-	17.1	10.75%	53.82%
GMO (Steam)	9/5/2008	1.3	-	1.3	10.75%	53.82%
KCP&L (MO)	9/5/2008	86.4	15.1	101.5	10.75%	53.82%
KCP&L (KS)	9/5/2008	60.4	11.2	71.6	10.75%	55.39%
Total		$ 231.2	$ 26.3	$ 257.5		

[a] Rate Jurisdiction Areas:
GMO (MPS): Represents the area served by GMO's Missouri Public Service division
GMO (L&P): Represents the area served by GMO's St. Joseph Light & Power division
GMO (Steam): GMO steam customers in the St. Joseph, Missouri, area
KCP&L (MO): KCP&L Missouri customers (not in former Aquila service territory)
KCP&L (KS): KCP&L Kansas customers

[b] The amounts in this column reflect the revenue requirements calculated using the traditional rate case methodologies, which exclude additional amortization amounts to help maintain cash flow levels

[c] Excludes amounts recovered through KCP&L's Kansas ECA and most of GMO's FAC and QCA

In February 2009, the MPSC and KCC staffs filed their respective testimony regarding the requests for annual rate increases filed by KCP&L and GMO. The following table details the rate increases recommended by the MPSC and KCC staffs by KCP&L and GMO jurisdiction.

	Annual Revenue Increase				
Rate Jurisdiction	Traditional	Additional Amortization	Total	Return on Equity	Rate-making Equity Ratio
		(millions)			
GMO (MPS) [a]	$ 46.0	$ -	$ 46.0	9.75%	51.03%
GMO (L&P) [a]	22.8	-	22.8	9.75%	51.03%
GMO (Steam) [a]	1.0	-	1.0	9.75%	51.03%
KCP&L (MO) [a]	45.2	[b]	45.2	9.75%	50.65%
KCP&L (KS)	42.6	11.2	53.8	11.40%	50.76%
Total	$ 157.6	$ 11.2	$ 168.8		

[a] Annual revenue increase and return on equity based on the mid-point of MPSC staff's return on equity range.

[b] Amount not included in the MPSC staff's February 2009 testimony, but will be included in the second quarter 2009 true up.

2009 Outlook
In 2009, electric utility is expected to have lower retail demand than in 2008 as a result of the slowing economy assuming normal weather conditions. If the current economic downturn continues or worsens, overall electricity MWh sales may continue to decline and/or bad debt expense may increase, which could materially affect Great Plains Energy's results of operations, financial position and cash flows. Electric utility's retail rates for GMO and in Kansas for KCP&L are covered by fuel recovery mechanisms, which are described under the heading "Electric Utility Results of Operations." KCP&L's Missouri retail rates do not include a fuel recovery mechanism, meaning changes in costs will not be reflected in rates until new rates are authorized by regulators. This regulatory lag between the time costs change and when they are reflected in rates applies to all costs, other than those included in fuel recovery mechanisms. In the current rising cost environment, regulatory lag can be expected to have an adverse impact on Great Plains Energy's results of operations. Additionally, continuing instability in the capital and credit markets have adversely affected, and could continue to adversely affect, Great Plains Energy's access to and cost of capital.

In response to these trends, management has taken the following measures:

- eliminated or deferred capital spending in 2009 and 2010,
- tightly managing operations and maintenance expense,
- freezing external hiring for all but essential skills and
- reduced the common stock dividend by 50%, from an annual level of $1.66 per share to $0.83 per share.

RELATED PARTY TRANSACTIONS

See Note 19 to the consolidated financial statements for information regarding related party transactions.

ENVIRONMENTAL MATTERS

See Note 16 to the consolidated financial statements for information regarding environmental matters.

CRITICAL ACCOUNTING POLICIES

The preparation of financial statements in conformity with Generally Accepted Accounting Principles (GAAP) requires management to make estimates and assumptions that affect reported amounts and related disclosures. Management considers an accounting estimate to be critical if it requires assumptions to be made that were uncertain at the time the estimate was made and changes in the estimate or different estimates that could have been used could have a material impact on Great Plains Energy's results of operations and financial position. Management has identified the following accounting policies as critical to the understanding of Great Plains Energy's 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
Great Plains Energy and KCP&L 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, life expectancies, compensation levels and employment periods), earnings on plan assets, the level of contributions made to the plan, 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.

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. The assumed discount rate was selected based on the prevailing market rate of fixed income debt instruments with maturities matching the expected timing of the benefit obligation. These assumptions, updated annually at the measurement date, are based on management's best estimates and judgment; however, material changes may occur if these assumptions differ from actual events. See Note 10 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 2008 Pension Expense
		(millions)	
Discount rate	0.5% increase	$ (49.0)	$ (4.3)
Rate of return on plan assets	0.5% increase	-	(2.0)
Discount rate	0.5% decrease	52.3	4.4
Rate of return on plan assets	0.5% decrease	-	2.0

Pension expense for KCP&L is recorded in accordance with rate orders from the MPSC and KCC. The orders allow the difference between pension costs under Statement of Financial Accounting Standards (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 pension costs for ratemaking to be recorded as a regulatory asset or liability with future ratemaking recovery or refunds, as appropriate. KCP&L recorded 2008 pension expense of $33 million after allocations to the other joint owners of generating facilities and capitalized amounts in accordance with the 2007 MPSC and KCC rate orders.

GMO records pension expense in accordance with rate orders from the MPSC. The difference between this expense and SFAS No. 87 expense is recorded as a regulatory asset or liability. See Note 10 to the consolidated financial statements for additional discussion of the accounting for pensions.

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

Electric utility is subject to the provisions of SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." Accordingly, Great Plains Energy and KCP&L have recorded assets and liabilities on their consolidated balance sheets 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 electric utility's regulators that may require refunds to customers; amounts provided in current rates that are intended to recover costs that are expected to be incurred in the future for which electric utility remains accountable; or 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 electric utility's rate case filings; decisions in other regulatory proceedings, including decisions related to other companies that establish precedent on matters applicable to electric utility; 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. Electric utility'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 electric utility'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 7 to the consolidated financial statements for additional information.

Impairments of Assets, Intangible Assets and Goodwill
Long-lived assets and intangible assets subject to amortization are periodically reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable as prescribed under SFAS No. 144.

Goodwill is 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." SFAS No. 142 requires that if the fair value of a reporting unit is less than its carrying value including goodwill, the implied fair value of the reporting unit goodwill must be compared with its carrying value to determine the amount of impairment. Great Plains Energy allocates goodwill from the GMO acquisition to KCP&L and GMO reporting units for impairment testing based upon the percentage of synergies expected from each reporting unit.

Impairment analyses require management to make assumptions about future sales, operating costs and discount rates over the life of the related asset, or in some cases over an indefinite life. Potential impairment indicators include such factors as current period losses combined with a history of losses, or a projection of continuing losses or a significant decrease in the market price of the asset under review. Management's assumptions about these factors require significant judgment and under different assumptions, the fair value of an asset could be materially different.

Accounting standards require a company to recognize an impairment in the current period results of operations if the sum of the undiscounted expected future cash flows from the company's asset is less than the carrying value of the asset. The impairment recognized is the difference between the fair value and carrying value of the asset.

During the fourth quarter of 2008, extraordinary levels of volatility and disruption in the stock market resulted in Great Plains Energy's equity securities trading at a stock price below carrying value. Management concluded that the fair value of the Company supported the GMO acquisition goodwill. However, there can be no assurance that continued market volatility with declines of extended duration and severity will not trigger impairment testing in the future, which could result in an impairment of goodwill prospectively.

Derivative Accounting
MPS Merchant's long-term natural gas contracts that qualify as derivatives under SFAS No. 133, ''Accounting for Derivative and Hedging Activities,'' are recorded under the mark-to-market method of accounting. MPS Merchant's portfolio consists of natural gas contracts that are settled by the delivery of the commodity or cash. The market prices or fair values used in determining the value of MPS Merchant's portfolio are management's best estimates utilizing information such as closing exchange rates, over-the-counter quotes, historical volatility and the potential impact on market prices of liquidating positions in an orderly manner over a reasonable amount of time under current market conditions. As additional information becomes available, or actual amounts are determinable, the recorded estimates are revised. As a result, operating results can be affected by revisions to prior accounting estimates.

The fair value of these derivative contracts are recorded as current or long-term derivative assets or liabilities. Changes in market prices will affect the recorded fair value of contracts. Natural gas market prices vary based upon a number of factors. Changes in the fair value of contracts will affect earnings in the period of the change for contracts under fair value accounting, while changes in forward market prices related to contracts under accrual accounting will affect earnings in future periods to the extent those prices are realized.

Derivative liabilities are discounted using the Company's credit standing, versus the receivable side of these transactions, which are discounted based on the counterparties' credit standings. As these spreads narrow, non-cash mark-to-market losses are recorded; as they widen, non-cash mark-to-market gains are recorded. These gains and losses can fluctuate if the Company's credit or the credit of a group of counterparties deteriorates or improves significantly.

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.

Income Taxes

Income taxes are accounted for using the asset/liability approach in accordance with SFAS No. 109, "Accounting for Income Taxes." Deferred tax assets and liabilities are determined based on the temporary differences between the financial reporting and tax bases of assets and liabilities, applying enacted statutory tax rates in effect for the year in which the differences are expected to reverse. Deferred investment tax credits are amortized ratably over the life of the related property. Deferred tax assets are also recorded for net operating loss, capital loss and tax credit carryforwards. The Company is required to estimate the amount of taxes payable or refundable for the current year and the deferred tax liabilities and assets for future tax consequences of events reflected in the Company's consolidated financial statements or tax returns. This process requires management to make assessments regarding the timing and probability of the ultimate tax impact. The Company records valuation allowances on deferred tax assets if it is determined that it is more likely than not that the asset will not be realized.

Additionally, the Company establishes reserves for uncertain tax positions based upon management's judgment regarding potential future challenges to those positions in accordance with FASB Interpretation (FIN) No. 48 "Accounting for Uncertainty in Income Taxes," an interpretation of SFAS No. 109, "Accounting for Income Taxes." Interest related to unrecognized tax benefits is recognized in interest expense and penalties are recognized as a non-operating expense. The accounting estimates related to the liability for uncertain tax positions require management to make judgments regarding the sustainability of each uncertain tax position based on its technical merits. If it is determined that it is more likely than not a tax position will be sustained based on its technical merits, the impact of the position is recorded in the Company's consolidated financial statements at the largest amount that is greater than fifty percent likely of being realized upon ultimate settlement. These estimates are updated at each reporting date based on the facts, circumstances and information available. Management is also required to assess at each reporting date whether it is reasonably possible that any significant increases or decreases to the unrecognized tax benefits will occur during the next twelve months. See Note 22 to the consolidated financial statements for additional information.

GREAT PLAINS ENERGY RESULTS OF OPERATIONS

The following table summarizes Great Plains Energy's comparative results of operations. GMO's results of operations are only included from the date of the acquisition, July 14, 2008, through December 31, 2008.

	2008	2007	2006
		(millions)	
Operating revenues	$ 1,670.1	$ 1,292.7	$ 1,140.4
Fuel	(311.4)	(245.5)	(229.5)
Purchased power	(208.9)	(101.0)	(26.4)
Other operating expenses	(639.8)	(523.0)	(462.7)
Skill set realignment deferral (costs)	-	8.9	(9.4)
Depreciation and amortization	(235.0)	(175.6)	(152.7)
Operating income	275.0	256.5	259.7
Non-operating income and expenses	21.1	3.2	9.3
Interest charges	(111.3)	(91.9)	(70.1)
Income tax expense	(63.8)	(44.9)	(60.3)
Minority interest in subsidiaries	(0.2)	-	-
Loss from equity investments	(1.3)	(2.0)	(1.9)
Income from continuing operations	119.5	120.9	136.7
Income (loss) from discontinued operations	35.0	38.3	(9.1)
Net income	154.5	159.2	127.6
Preferred dividends	(1.6)	(1.6)	(1.6)
Earnings available for common shareholders	$ 152.9	$ 157.6	$ 126.0

2008 compared to 2007

Great Plains Energy's 2008 earnings available for common shareholders decreased to $152.9 million, or $1.51 per share, from $157.6 million, or $1.85 per diluted share in 2007. A higher number of common shares, primarily due to the issuance of 32.2 million shares for the acquisition of GMO, diluted 2008 earnings per share by $0.28.

Electric utility's net income decreased $13.7 million in 2008 compared to 2007. This decrease was primarily due to mild summer weather, a decrease in wholesale sales, higher fuel costs, higher purchased power prices and planned and unplanned plant outages which led to increased operating expenses at KCP&L. Also, in 2007, KCP&L received authorization from the MPSC and KCC to defer $8.9 million of skill set realignment costs incurred in 2006 resulting in lower expenses in 2007. Partially offsetting these decreases were increased retail revenues primarily due to new retail rates at KCP&L effective January 1, 2008 and an increase in AFUDC at KCP&L. The acquisition of GMO increased electric utility's net income $17.9 million.

Great Plains Energy's corporate and other activities loss from continuing operations decreased $12.3 million in 2008 compared to 2007, primarily due to $3.4 million of after-tax income related to the release of a legal reserve described in Note 17 to the consolidated financial statements, the reversal of $3.6 million of after-tax interest expense related to unrecognized tax benefits, a $3.8 million after-tax favorable impact from the deferral in 2008 of merger transition costs incurred in 2007 to a regulatory asset and a $4.6 million after-tax change in the fair value of Forward Starting Swaps (FSS). The acquisition of GMO increased Great Plains Energy's corporate and other activities loss $5.4 million.

2007 compared to 2006

Great Plains Energy's 2007 earnings available for common shareholders increased to $157.6 million, or $1.85 per diluted share, from $126.0 million, or $1.61 per diluted share in 2006. A higher number of common shares, primarily due to the issuance of 5.2 million shares to the holders of FELINE PRIDES^{SM} in February 2007 and 5.2 million shares in May 2006, diluted 2007 earnings per share by $0.17.

Electric utility's net income increased $7.2 million in 2007 compared to 2006 due to increased retail and wholesale revenues, which more than offset the impact of planned and unplanned outages during the first half of the year that lead to increased fuel, purchased power and operating expenses. Additionally, in 2006 KCP&L recorded $9.3 million of skill set realignment costs and in 2007 received authorization from the MPSC and KCC to defer $8.9 million of these costs to be amortized in future years.

Great Plains Energy's corporate and other activities recognized an additional $23.0 million net loss in 2007 compared to 2006, which was primarily attributable to a decline in available tax credits from affordable housing investments and overall higher expenses at the holding company, including $11.7 million of transition costs related to the anticipated acquisition of GMO, and a $10.3 million after-tax loss for the fair value of FSS entered into by Great Plains Energy during 2007.

ELECTRIC UTILITY RESULTS OF OPERATIONS

The following table summarizes the electric utility segment results of operations.

	2008	2007	2006
		(millions)	
Operating revenues	$ 1,670.1	$ 1,292.7	$ 1,140.4
Fuel	(311.4)	(245.5)	(229.5)
Purchased power	(209.9)	(101.0)	(26.4)
Other operating expenses	(624.2)	(500.4)	(451.5)
Skill set realignment deferral (costs)	-	8.9	(9.3)
Depreciation and amortization	(235.0)	(175.6)	(152.7)
Operating income	289.6	279.1	271.0
Non-operating income and expenses	21.3	4.2	11.1
Interest charges	(96.9)	(67.2)	(60.9)
Income tax expense	(70.9)	(59.3)	(71.6)
Net income	$ 143.1	$ 156.8	$ 149.6

Electric utility'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. Electric utility's revenues contain certain fuel recovery mechanisms as follows:

- KCP&L's Kansas retail rates effective January 1, 2008, contain an ECA tariff. The ECA tariff reflects the projected annual amount of fuel, purchased power, emission allowances, transmission costs and asset-based off-system sales margin. These projected amounts are subject to quarterly re-forecasts. Any difference between the ECA revenue collected and the actual ECA amounts for a given year (which may be positive or negative) is recorded as an increase to or reduction of retail revenues and deferred as a regulatory asset or liability to be recovered from or refunded to Kansas retail customers over twelve months beginning April 1 of the succeeding year.

- GMO's electric retail rates contain a FAC under which 95% of the difference between actual fuel and purchased power costs and the amount of fuel and purchased power costs provided in base rates is passed along to GMO's customers. The FAC cycle consists of an accumulation period of six months beginning in June and December. FAC rate approval is requested every six months for a twelve month recovery period. The FAC is recorded as an increase to or reduction of retail revenues and deferred as a regulatory asset or liability to be recovered from or refunded to GMO's electric retail customers.

- GMO's steam rates contain a Quarterly Cost Adjustment (QCA) under which 80% of the difference between actual fuel costs and base fuel costs is passed along to GMO's steam customers. The QCA is

recorded as an increase to or reduction of other revenues and deferred as a regulatory asset or liability to be recovered from or refunded to GMO's steam customers.

KCP&L's Missouri retail rates do not contain a similar adjustment mechanism, meaning that changes in costs will not be reflected in rates until new rates are authorized by the MPSC. This regulatory lag between the time costs change and when they are reflected in rates applies to all costs not included in fuel recovery mechanisms as described above. In the current rising cost environment, regulatory lag can be expected to have an adverse impact on Great Plains Energy's results of operations.

Generation fuel mix can substantially change the fuel cost per MWh generated. Generation fuel mix can be significantly impacted by planned and unplanned plant outages. 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. Electric utility continually evaluates its system requirements, the availability of generating units, its demand-side management and efficiency programs, availability and cost of fuel supply and purchased power, and the requirements of other electric systems to provide reliable power economically.

Electric Utility Revenues and MWh Sales

	2008	% Change [a]	2007	% Change	2006
Retail revenues			(millions)		
Residential	$ 605.5	NM	$ 433.8	13	$ 384.3
Commercial	620.7	NM	492.1	11	442.6
Industrial	142.2	NM	106.8	7	99.8
Other retail revenues	13.3	NM	9.9	12	8.8
Provision for rate refund (excess Missouri wholesale margin)	(2.9)	NM	(1.1)	NA	-
Fuel recovery mechanism under recovery	30.7	NM	-	NA	-
Total retail	1,409.5	NM	1,041.5	11	935.5
Wholesale revenues	230.1	NM	234.0	23	190.4
Other revenues	30.5	NM	17.2	19	14.5
Total revenues	$ 1,670.1	NM	$ 1,292.7	13	$ 1,140.4

	2008	% Change [a]	2007	% Change	2006
Retail MWh sales			(thousands)		
Residential	7,047	NM	5,597	3	5,413
Commercial	9,227	NM	7,737	5	7,403
Industrial	2,721	NM	2,161	1	2,148
Other retail MWh sales	94	NM	92	8	86
Total retail	19,089	NM	15,587	4	15,050
Wholesale MWh sales	5,237	NM	5,635	21	4,676
Total MWh sales	24,326	NM	21,222	8	19,726

[a] Not meaningful due to the acquisition of GMO on July 14, 2008.

Retail revenues increased $368.0 million in 2008 compared to 2007. The acquisition of GMO increased retail revenue $306.2 million. New retail rates, effective January 1, 2008, at KCP&L also increased retail revenue. These increases were partially offset by mild summer weather in 2008, with a 27% decrease in cooling degree days.

Retail revenues increased $106.0 million in 2007 compared to 2006 primarily due to new retail rates effective January 1, 2007, growth in the number of customers and higher usage per customer. In addition, favorable weather in 2007, with a 22% increase in heating degree days partially offset by a 5% decrease in cooling degree days, contributed to the increase in retail revenue.

The following table provides cooling degree days (CDD) and heating degree days (HDD) for the last three years at the Kansas City International Airport. CDD and HDD are used to reflect the demand for energy to cool or heat homes and buildings.

	2008	% Change	2007	% Change	2006
CDD	1,196	(27)	1,637	(5)	1,724
HDD	5,590	14	4,925	22	4,052

Wholesale revenues decreased $3.9 million in 2008 compared to 2007 due to an 11% decrease in wholesale MWh sales resulting from less generation at KCP&L due to plant outages. This decrease was partially offset by a 9% increase in the average market price power per MWh to $46.34, primarily due to higher natural gas prices. The acquisition of GMO increased wholesale revenues $8.6 million.

Wholesale revenues increased $43.6 million in 2007 compared to 2006 due to a 21% increase in wholesale MWh sales resulting from increased generation due to greater plant availability in the second half of the year.

Electric Utility Fuel and Purchased Power

	2008	% Change	2007	% Change	2006
Net MWhs Generated by Fuel Type			(thousands)		
Coal	16,793	NM[a]	14,894	(1)	15,056
Nuclear	3,994	(18)	4,873	11	4,395
Natural gas and oil	486	NM[a]	544	(4)	564
Wind	419	38	305	NM	106
Total Generation	21,692	NM[a]	20,616	2	20,121

[a] Not meaningful due to the acquisition of GMO on July 14, 2008.

KCP&L's coal base load equivalent availability factor for 2008, decreased to 78% from 80% in 2007 and from 83% in 2006. GMO's coal base load equivalent availability factor since the July 14, 2008, acquisition was 66% which was negatively impacted by scheduled plant outages in the last half of 2008.

KCP&L's nuclear unit, Wolf Creek, accounts for approximately 15% of electric utility's base load capacity. Wolf Creek's latest refueling outage began on March 20, 2008, and there were several increases in work scope during the outage that extended the restart until May 14, 2008. A primary driver of the work scope increases was modifications to piping systems associated with the emergency core cooling systems. As a result of the outage, the capacity and equivalent availability factor for Wolf Creek decreased to 83% in 2008 compared to 100% for 2007.

Fuel expense increased $65.9 million in 2008 compared to 2007. The acquisition of GMO increased fuel expense $58.1 million. The remaining increase was at KCP&L, primarily due to higher coal and coal transportation costs and less nuclear in the fuel mix, which has a lower cost compared to other fuel types. These increases were partially offset by decreased MWhs generated by KCP&L, primarily due to lower system requirements.

Fuel expense increased $16.0 million in 2007 compared to 2006 primarily due to higher coal and coal transportation costs and a 2% increase in MWhs generated, excluding wind generation, which has no fuel cost. This increase was partially offset by changes in the fuel mix with more nuclear and less coal and natural gas in the fuel mix.

Purchased power expense increased $108.9 million in 2008 compared to 2007. The acquisition of GMO increased purchased power expense $90.9 million. The remaining increase at KCP&L was primarily due to a 26% increase in the average price per MWh as a result of higher natural gas prices. Additionally, an 8% increase in MWh purchases primarily due to the impact of the Wolf Creek refueling outage increased purchased power expense. These increases were partially offset by $6.9 million in recoveries from a litigation settlement regarding a 2005 transformer failure.

Purchased power expense increased $74.6 million in 2007 compared to 2006 primarily due to a 240% increase in MWh purchases to support increased retail load, the impact of planned and unplanned outages in the first half of 2007 and increased purchases for resale to satisfy firm wholesale MWh sales commitments when it was more economical to purchase power rather than delivering MWhs generated at KCP&L's plants. This increase was slightly offset by a 10% decrease in the average price per MWh.

Electric Utility Other Operating Expenses ***(including utility operating expenses, maintenance, general taxes and other)***

Electric utility's other operating expenses increased $123.8 million in 2008 compared to 2007 primarily due to the following:

- the acquisition of GMO increased operating expenses $95.9 million,
- increased plant operations and maintenance expenses of $12.2 million due to plant outages,
- increased employee-related costs of $5.5 million,
- increased property taxes of $3.0 million due to higher assessments and higher mill levies and
- increased gross receipts tax expense of $2.1 million due to the increase in revenues.

Electric utility's other operating expenses increased $48.9 million in 2007 compared to 2006 primarily due to the following:

- increased pension expenses of $18.4 million due to the increased level of pension costs in KCP&L's rates effective January 1, 2007,
- increased plant operations and maintenance expenses of $9.7 million primarily due to planned and unplanned outages in the first half of 2007 and the addition of the Spearville Wind Energy Facility in the third quarter of 2006,
- increased transmission expenses of $7.7 million primarily due to increased transmission usage charges as a result of the increased wholesale MWh sales and higher SPP fees,
- increased gross receipts tax expense of $3.6 million due to the increase in revenues,
- increased labor expense of $2.8 million primarily due to filling open positions,
- increased equity compensation expense of $1.9 million and
- increased property taxes of $1.6 million primarily due to increases in mill levies.

Partially offsetting the increases in other operating expenses was decreased incentive compensation expense of $5.7 million.

Electric Utility Skill Set Realignment
In 2005 and early 2006, management undertook a process to assess, improve and reposition the skill sets of employees for implementation of KCP&L's 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 2007, KCP&L received authorization from the MPSC and KCC to establish $8.9 million in regulatory assets for these costs and amortize them over five years for the Missouri jurisdictional portion and ten years for the Kansas jurisdictional portion effective with new rates on January 1, 2008.

Electric Utility Depreciation and Amortization
Electric utility's depreciation and amortization costs increased $59.4 million in 2008 compared to 2007. The acquisition of GMO increased depreciation and amortization $30.7 million. The remaining increase at KCP&L was primarily due to additional amortization pursuant to rate case orders of $21.7 million combined with normal depreciation activity for capital additions.

Electric utility's depreciation and amortization costs increased $22.9 million in 2007 compared to 2006 primarily due to additional amortization pursuant to 2006 rate case orders of $11.9 million and a $4.5 million increase due to wind generation assets placed in service in the third quarter of 2006.

Electric Utility Non-Operating Income and Expenses
Electric utility's non-operating income and expenses increased $17.1 million in 2008 compared to 2007. The acquisition of GMO increased non-operating income and expenses $2.1 million. The remaining increase at KCP&L was primarily due to an increase in the equity component of AFUDC resulting from a higher construction work in progress balance due to Comprehensive Energy Plan projects.

Electric Utility Interest Charges
Electric utility's interest charges increased $29.7 million in 2008 compared to 2007. The acquisition of GMO increased interest charges $24.6 million. The remaining increase at KCP&L was primarily due to interest on $350.0 million of 6.375% unsecured Senior Notes issued in March 2008, partially offset by an increase in the debt component of AFUDC resulting from a higher construction work in progress balance due to Comprehensive Energy Plan projects.

Electric utility's interest charges increased $6.3 million in 2007 compared to 2006 due to an increase in short-term borrowings to support expenditures related to KCP&L's Comprehensive Energy Plan.

Electric Utility Income Tax Expense
Electric utility's income tax expense increased $11.6 million in 2008 compared to 2007. The acquisition of GMO increased income taxes $11.1 million. The remaining increase was primarily due to an increase of $20.3 million as a result of an increase in the composite tax rate reflecting the sale of Strategic Energy, mostly offset by decreased pre-tax income and increased wind credits. See Note 22 to the consolidated financial statements for a reconciliation of effective income tax rates for the periods.

Electric utility's income tax expense decreased $12.3 million in 2007 compared to 2006 primarily due to $4.1 million of wind credits and a $7.3 million increase in the allocation of tax benefits from holding company losses pursuant to Great Plains Energy's intercompany tax allocation agreement.

GREAT PLAINS ENERGY SIGNIFICANT BALANCE SHEET CHANGES (December 31, 2008 compared to December 31, 2007)

The following table summarizes significant balance sheet changes due to the acquisition of GMO.

	Total Change	December 31, 2008 GMO	Remaining Change
Assets		(millions)	
Cash and cash equivalents	$ 37.1	$ 31.5	$ 5.6
Funds on deposit	10.8	10.8	-
Receivables, net	76.3	109.2	(32.9)
Fuel inventories, at average cost	51.1	35.3	15.8
Materials and supplies, at average cost	35.3	31.0	4.3
Refundable income taxes	10.0	3.4	6.6
Deferred income taxes	25.0	23.2	1.8
Assets held for sale	16.3	16.3	-
Derivative instruments - current	4.1	4.2	(0.1)
Other nonutility property and investments	33.6	35.9	(2.3)
Net utility plant in service	1,504.6	1,425.7	78.9
Construction work in progress	1,128.9	510.6	618.3
Regulatory assets	424.7	215.7	209.0
Goodwill	156.0	156.0	-
Derivative instruments - long-term	13.0	13.0	-
Liabilities			
Notes payable	162.0	174.0	(12.0)
Current maturities of long-term debt	70.4	70.7	(0.3)
Accounts payable	176.6	121.7	54.9
Accrued taxes	8.2	7.1	1.1
Accrued interest	55.8	52.2	3.6
Pension and post-retirement liability - current	3.4	3.1	0.3
Derivative instruments - current	41.8	5.9	35.9
Other current liabilities	33.6	32.1	1.5
Deferred income taxes	(220.9)	(194.8)	(26.1)
Deferred tax credits	78.5	5.6	72.9
Asset retirement obligations	29.8	12.4	17.4
Pension and post-retirement liability - long-term	288.4	35.0	253.4
Regulatory liabilities	65.3	93.6	(28.3)
Other deferred credits and other liabilities	39.3	54.1	(14.8)
Long-term debt	1,453.7	1,080.1	373.6

The following are significant balance sheet changes in addition to the impacts due to the acquisition of GMO.

- Great Plains Energy's receivables, net decreased $32.9 million due to a $29.2 million decrease in receivables from joint owners primarily related to Comprehensive Energy Plan projects and a $22.7 million decrease in receivables from wholesale power sales. Partially offsetting these decreases was a $10.0 million receivable related to KCP&L's Series 2008 EIRR bonds issued in May 2008 and a $12.0 million increase in customer receivables due to new retail rates and higher usage due to colder weather in December 2008.
- Great Plains Energy's fuel inventories increased $15.8 million at KCP&L primarily due to decreased generation resulting from planned and unplanned plant outages and increased coal and coal transportation prices.

- Great Plains Energy's construction work in progress increased $618.3 million at KCP&L primarily due to a $536.1 million increase related to KCP&L's Comprehensive Energy Plan, including $369.8 million related to the construction of Iatan No. 2 and $166.3 million for environmental upgrades.
- Great Plains Energy's regulatory assets increased $209.0 million at KCP&L due to a reduction of plan assets in the pension and post-retirement plans as a result of unprecedented levels of volatility and disruption in the stock and credit markets. As a regulated utility, KCP&L expects to recover any pension and post-retirement liabilities from ratepayers and, as a result, recorded a regulatory asset to offset losses in plan assets.
- Great Plains Energy's accounts payable increased $54.9 million due to increased payables related to Comprehensive Energy Plan projects, higher purchased power prices and the timing of cash payments.
- Great Plains Energy's derivative instruments – current liabilities increased $35.9 million primarily due to a $63.7 million decline in the fair value of FSS that were assigned from Great Plains Energy to KCP&L, partially offset by a decrease of $28.0 million at KCP&L related to the settlement of a Treasury Lock (T-Lock) simultaneously with the issuance of $350.0 million of 6.375% Senior Notes in March 2008.
- Great Plains Energy's deferred tax credits increased $72.9 million due to recognition of $74.2 million of advanced coal credits. See Note 22 to the consolidated financial statements for additional information on the advanced coal credits.
- Great Plains Energy's asset retirement obligations increased $17.4 million primarily due to KCP&L recording $14.2 million of changes in cost estimates and timing used in computing the present value of certain asbestos Asset Retirement Obligations (AROs). See Note 9 to the consolidated financial statements for additional information.
- Great Plains Energy's pension and post-retirement liability – long-term increased $253.4 million due to unprecedented levels of volatility and disruption in the stock and credit markets which resulted in large reductions in the value of plan assets.
- Great Plains Energy's regulatory liabilities decreased $28.3 million at KCP&L primarily due to a reclassification to accumulated depreciation, consistent with ratemaking treatment, of the regulatory liability for additional Wolf Creek amortization (Missouri) of $14.6 million.
- Great Plains Energy's other – deferred credits and other liabilities decreased $14.8 million due to the payment against and release of a legal reserve.
- Great Plains Energy's long-term debt increased $373.6 million due to KCP&L's issuance of $350.0 million of 6.375% Senior Notes in March 2008 and $23.4 million of Series 2008 EIRR bonds in May 2008.

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, proceeds from the issuance of its securities and borrowing under its revolving credit facility.

Great Plains Energy's capital requirements are principally comprised of debt maturities and electric utility's utility construction and other capital expenditures. These items as well as additional cash and capital requirements are discussed below.

Great Plains Energy's liquid resources at December 31, 2008, consisted of $61.1 million of cash and cash equivalents on hand and $832.2 million of unused bank lines of credit. The unused lines consisted of $207.9 million from KCP&L's revolving credit facility, $289.2 million from GMO's credit facilities and $335.1 million from Great Plains Energy's revolving credit facility. At February 20, 2009, Great Plains Energy's unused bank lines of credit decreased $202.9 million from the amount at December 31, 2008, primarily to support expenditures for Comprehensive Energy Plan projects. See Note 12 to the consolidated financial statements for more information on these agreements.

Great Plains Energy intends to meet day-to-day cash flow requirements including interest payments, retirement of maturing debt, construction requirements (excluding KCP&L's Comprehensive Energy Plan), dividends and pension benefit plan funding requirements, discussed below, with a combination of internally generated funds and proceeds from the issuance of short-term and long-term debt, equity securities or equity-linked securities. Great Plains Energy's intention to meet a portion of these requirements with internally generated funds may; however, be impacted by the effect of inflation on operating expenses, the level of MWh sales, regulatory actions, compliance with environmental regulations and the availability of generating units. In addition, Great Plains Energy may issue debt, equity and/or equity-linked securities to finance growth or take advantage of new opportunities.

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 security issuances and new short and long-term debt financing.

KCP&L's primary means of short-term financing is the issuance of commercial paper. Commercial paper market conditions were extremely difficult in the late third quarter and early fourth quarter of 2008. Despite this, KCP&L maintained uninterrupted access to the commercial paper market, although at higher rates and shorter terms than historically. As the fourth quarter progressed, conditions in the commercial paper market improved and KCP&L benefited in terms of both longer available terms and lower rates.

In February 2009, Great Plains Energy reduced its annual common dividend from $1.66 per common share to $0.83 per common share, which will reduce annual cash requirements for dividend payments by approximately $100 million from the level required if the prior dividend had been maintained.

Great Plains Energy presently believes it has the necessary liquidity to effectively conduct business operations for much of 2009 if capital markets were to become inaccessible. Instability in the capital and credit markets such as which occurred in the fourth quarter of 2008, could adversely affect Great Plains Energy's access and cost of needed capital.

Cash Flows from Operating Activities

Great Plains Energy generated positive cash flows from operating activities for the periods presented. The increase in cash flows from operating activities for Great Plains Energy in 2008 compared to 2007 reflects an increase in KCP&L's cash flows due to a decrease in accounts receivable from wholesale sales and joint owners and tax refunds received in 2008 partially offset by payment of $41.2 million for the settlement of three T-Locks. Other changes in working capital are detailed in Note 3 to the consolidated financial statements.

The increase in cash flows from operating activities for Great Plains Energy in 2007 compared to 2006 reflects an increase in KCP&L's cash flows due to higher retail and wholesale revenues more than offsetting higher operating expenses combined with $24.0 million in proceeds from sales of SO_2 emission allowances in 2007. This increase was partially offset by a $15.5 million increase in deferred acquisition costs at Great Plains Energy and a lower retail margin per MWh without the impact of unrealized fair value gains and losses at Strategic Energy. Other changes in working capital detailed in Note 3 to the consolidated financial statements also impacted operating cash flows.

Cash Flows from Investing Activities
Great Plains Energy'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 utility capital expenditures increased $512.2 million in 2008 compared to 2007. The acquisition of GMO increased cash utility capital expenditures $213.2 million and KCP&L's cash utility capital expenditures increased $299.0 million due to a $285.7 million increase related to KCP&L's Comprehensive Energy Plan.

In 2008, Great Plains Energy completed the sale of Strategic Energy and received gross cash proceeds of $307.7 million. At the time of the sale, Strategic Energy had $88.9 million of cash, resulting in proceeds from the sale of Strategic Energy, net of cash sold of $218.8 million.

On July 14, 2008, Great Plains Energy closed its acquisition of GMO. Great Plains Energy paid cash consideration of $0.7 billion. At the time of the acquisition, GMO had approximately $1.0 billion of cash from the sale of its electric utility assets in Colorado, Kansas, Nebraska and Iowa to Black Hills.

Great Plains Energy's utility capital expenditures increased $35.6 million in 2007 compared to 2006 due to KCP&L's cash utility expenditures, including $27.0 million related to KCP&L's Comprehensive Energy Plan.

Cash Flows from Financing Activities
Great Plains Energy's cash flows from financing activities in 2008 reflect KCP&L's issuance of $350.0 million of 6.375% unsecured Senior Notes that mature in 2018. The proceeds were used to repay short-term borrowings. GMO repaid $169.0 million on a credit agreement that was terminated in the third quarter of 2008 and subsequently borrowed $110.0 million under its new revolving credit facility. Additionally, GMO terminated various other credit agreements and paid $12.5 million of termination fees.

Great Plains Energy's cash flows from financing activities in 2007 reflect KCP&L's repayment and issuance of Senior Notes; Great Plains Energy's issuance, at a discount, of $100.0 million of 6.875% Senior Notes that mature in 2017; an increase in short-term borrowings and the $12.3 million settlement of an equity forward contract at Great Plains Energy. KCP&L's cash flows from financing activities in 2007 reflect KCP&L's repayment of its $225.0 million of 6.00% Senior Notes at maturity, issuance, at a discount, of $250.0 million of 5.85% Senior Notes that mature in 2017, and an increase in short-term borrowings. KCP&L's short-term borrowings have increased primarily to support expenditures related to its Comprehensive Energy Plan.

Great Plains Energy's cash flows from financing activities in 2006 reflect 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 to support expenditures related to KCP&L's Comprehensive Energy Plan.

Financing Authorization
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 2008, the MPSC increased KCP&L's authorization to issue long-term debt and to enter into interest rate hedging instruments in connection with such debt to $1.4 billion through December 31, 2009. KCP&L has utilized $850.0 million of this amount with the issuance of its 6.05% unsecured senior notes maturing in 2035, its 5.85% unsecured senior notes maturing in 2017 and it 6.375% unsecured Senior Notes maturing in 2018, leaving $550.0 million of authorization remaining. In addition, in February 2009, KCP&L received authorization to issue $196.5 million in mortgage bonds to insurers of KCP&L's $196.5 million aggregate principal amount of EIRR Bonds Series 2005 and Series 2007, if and as required under the terms of the insurance agreements due to the issuance of other mortgage bonds by KCP&L. See Note 13 to the consolidated financial statements for more information on these insurance agreements.

In December 2008, FERC authorized KCP&L to have outstanding at any time up to a total of $1.1 billion in short-term debt instruments through December 2010. The authorization is 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. At December 31, 2008, there was $719.8 million available under this authorization. KCP&L is also authorized to participate in the Great Plains Energy money pool. The money pool is an internal financing arrangement in which funds deposited into the money pool could be lent on a short-term basis to KCP&L and GMO. At December 31, 2008, there were no borrowings under the money pool.

GMO has $500.0 million of FERC short-term debt authorization. At December 31, 2008, there was $326.0 million available under this authorization.

Significant Financing Activities

Great Plains Energy

Great Plains Energy has an effective shelf registration statement for the sale of unspecified amounts of securities that was filed and became effective in May 2006.

On August 14, 2008, Great Plains Energy entered into a Sales Agency Financing Agreement with BNY Mellon Capital Markets, LLC (BNYMCM). Under the terms of the agreement, Great Plains Energy may offer and sell up to 8,000,000 shares of its common stock from time to time through BNYMCM, as agent, for a period of no more than three years. The Company will pay BNYMCM a commission equal to 1% of the sales price of all shares sold under the agreement. As of December 31, 2008, 189,300 shares had been sold for $3.5 million in net proceeds through BNYMCM.

During 2007, Great Plains Energy issued $100.0 million of 6.875% unsecured Senior Notes. Great Plains Energy used the proceeds to make a $94.0 million equity contribution to KCP&L.

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.

In April 2007, Great Plains Energy elected to terminate a forward sale agreement with Merrill Lynch Financial Markets, Inc. for 1.8 million shares of Great Plains Energy common stock and settle it in cash. Based on the difference between Great Plains Energy's average stock price of $32.60 over the period used to determine the settlement and the then-applicable forward price of $25.58, Great Plains Energy paid $12.3 million to Merrill Lynch Financial Markets, Inc.

In 2007, Great Plains Energy entered into three FSS, with a total notional amount of $250.0 million, to hedge against interest rate fluctuations on future issuances of long-term debt. The three FSS were designed to effectively remove most of the interest rate uncertainty and, to the extent that swap spreads correlate with credit spreads, some degree of credit spread uncertainty with respect to the debt to be issued, thereby enabling Great Plains Energy to predict with greater assurance its future interest costs on that debt. Following a change in financing plans, Great Plains Energy assigned the three FSS to KCP&L.

KCP&L

KCP&L has an effective shelf registration statement providing for the sale of up to $900.0 million of investment grade notes and general mortgage bonds that became effective in January 2008. There is currently $550.0 million of capacity under this registration statement.

In March 2008, KCP&L issued $350.0 million of 6.375% unsecured Senior Notes, maturing in 2018. KCP&L settled three T-Locks simultaneously with the issuance of its $350.0 million 10-year long-term debt and paid $41.2 million in cash for the settlement.

In 2008, KCP&L remarketed several series of EIRR bonds that were auction rate securities, i.e. the interest rates were periodically reset through an auction process, as follows:

- secured Series 1992 EIRR bonds maturing in 2017 totaling $31.0 million at a fixed rate of 5.25% through March 31, 2013,
- secured Series 1993A EIRR bonds maturing in 2023 totaling $40.0 million at a fixed rate of 5.25% through March 31, 2013,
- unsecured Series 2007B EIRR bonds maturing in 2035 totaling $73.2 million at a fixed rate of 5.375% through March 31, 2013,
- secured Series 1993B EIRR bonds maturing in 2023 totaling $39.5 million at a fixed rate of 5.00% through March 31, 2011, and
- unsecured Series 2007A EIRR bonds maturing in 2035 into two series: Series 2007A-1 totaling $63.3 million at a fixed rate of 5.125% through March 31, 2011 and Series 2007A-2 totaling $10.0 million at a fixed rate of 5.00% through March 31, 2010.

After these remarketing activities, none of KCP&L's EIRR bonds are in auction rate mode.

In May 2008, KCP&L's Series 2008 EIRR bonds totaling $23.4 million maturing in 2038 were issued. Proceeds of the bonds will be used to pay for a portion of the costs at the Iatan Nos. 1 and 2 projects included in KCP&L's Comprehensive Energy Plan. The proceeds were deposited with a trustee, and will be used to reimburse KCP&L for qualifying expenditures. At December 31, 2008, KCP&L had received $13.4 million in cash proceeds and had a $10.0 million short-term receivable for the proceeds that were deposited with the trustee. The bonds have an initial long-term interest rate of 4.90% until June 30, 2013. At the end of the initial long-term interest rate period, the bonds are subject to mandatory tender; however, KCP&L is not obligated to pay the purchase price of the bonds on the mandatory tender date. If the bonds are not successfully remarketed, the bonds will bear interest at a daily rate equal to 10% per annum until all of the bonds are successfully remarketed.

In 2007, KCP&L's Series 2007A and 2007B unsecured EIRR Bonds totaling $146.5 million maturing in 2035 were issued. The EIRR Bonds Series 2007A and 2007B are covered by a municipal bond insurance policy issued by Financial Guaranty Insurance Company (FGIC). The insurance agreement between KCP&L and FGIC provides for reimbursement by KCP&L for any amounts that FGIC pays under the municipal bond insurance policy. The insurance policy is in effect for the term of the bonds. The policy also restricts the amount of secured debt KCP&L may issue. In the event KCP&L issues debt secured by liens not permitted by the agreement, KCP&L is required to issue and deliver to FGIC first mortgage bonds or similar securities equal in principal amount to the principal amount of the EIRR Bonds Series 2007A and 2007B then outstanding. The proceeds from the issuance of $146.5 million EIRR Bonds Series 2007A and 2007B were used for the repayment of $146.5 million of Series 1998 A, B and D EIRR bonds.

In 2007, KCP&L issued $250.0 million of 5.85% unsecured Senior Notes. The proceeds from this issuance were used to repay a short-term intercompany loan from Great Plains Energy. KCP&L used the proceeds from the intercompany loan to repay its $225.0 million unsecured 6.00% Senior Notes at maturity.

Debt Agreements
See Note 12 to the consolidated financial statements for discussion of revolving credit facilities.

Projected Utility Capital Expenditures
Great Plains Energy's cash utility capital expenditures, excluding AFUDC to finance construction, were $1,023.7 million, $511.5 million and $475.9 million in 2008, 2007 and 2006, respectively. Utility capital expenditures projected for the next three years, excluding AFUDC, are detailed in the following table.

	2009	2010	2011
Base utility construction expenditures		(millions)	
Generating facilities	$ 104.3	$ 129.5	$ 247.0
Distribution and transmission facilities	161.7	219.3	301.1
General facilities	52.6	47.1	68.8
Total base utility construction expenditures	318.6	395.9	616.9
Comprehensive Energy Plan capital expenditures			
Iatan No. 2 (KCP&L Share)	276.8	113.4	-
Environmental	43.1	-	-
Customer programs & asset management	11.1	5.1	-
Total Comprehensive Energy Plan capital expenditures	331.0	118.5	-
Nuclear fuel	20.6	28.7	22.9
Iatan No. 2 (GMO Share)	90.7	37.3	-
Other environmental	31.4	41.4	216.3
Customer programs & asset management	6.3	3.7	4.3
Total utility capital expenditures	$ 798.6	$ 625.5	$ 860.4

This utility capital expenditure plan is subject to continual review and change.

Pensions
The Company maintains defined benefit plans for substantially all active and inactive employees, including officers, of KCP&L, GMO and WCNOC and incurs significant costs in providing the plans. Funding of the plans equals or exceeds the minimum requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). In 2008, the Company contributed $29.3 million to the plans to satisfy the ERISA funding requirements and the 2007 MPSC and KCC rate orders and in 2007 contributed $32.7 million to the plans, all paid by KCP&L.

The Company expects to contribute $45.2 million to the plans in 2009 to satisfy the funding requirements of ERISA and the MPSC and KCC rate orders, of which the majority will be paid by KCP&L. This doesn't include additional voluntary contributions that may be made to address funding levels affected by recent market declines. Due to the economic downturn, The Worker, Retiree and Employer Recovery Act (WRERA) was signed into law on December 23, 2008, to provide some funding relief from the requirements of the PPA which was generally effective for plan years beginning in 2008. Among other things, WRERA relaxes the PPA transition rules for phasing in liability targets.

With the GMO acquisition on July 14, 2008, Black Hills assumed the pension obligation and a portion of the plan assets related to the current and former employees of GMO's electric and gas utility operations acquired by Black Hills under the terms of the purchase agreement. The final transfer of plan assets is expected to be completed in the first quarter of 2009 at which time the Company expects to make a voluntary contribution of approximately $12 million to sustain the funded status of the plans.

Management believes the Company has adequate access to capital resources through a combination of cash flows from operations and existing lines of credit to support the funding requirements.

Credit Ratings
At December 31, 2008, the major credit rating agencies rated Great Plains Energy's and KCP&L's securities as detailed in the following table.

	Moody's Investors Service	Standard & Poor's
Great Plains Energy		
Outlook	Negative	Stable
Corporate Credit Rating	-	BBB
Preferred Stock	Ba1	BB+
Senior Unsecured Debt	Baa2	BBB-
KCP&L		
Outlook	Negative	Stable
Senior Secured Debt [(a)]	A2	BBB
Senior Unsecured Debt	A3	BBB
Commercial Paper	P-2	A-2
GMO		
Outlook	Negative	Stable
Senior Secured Debt [(b)]	Baa2	BBB+
Senior Unsecured Debt [(b)]	Baa2	BBB

[(a)] In February 2009, Standard & Poor's upgraded to BBB+
[(b)] reflects Great Plains Energy guarantee

A securities rating is not a recommendation to buy, sell or hold securities and may be subject to revision or withdrawal at any time by the assigning rating agency. Great Plains Energy and KCP&L view maintenance of strong credit ratings as extremely important and to that end an active and ongoing dialogue is maintained with the agencies with respect to results of operations, financial position, and future prospects. While a decrease in these credit ratings would not cause any acceleration of Great Plains Energy's, KCP&L's or GMO's debt, it could increase interest charges under Great Plains Energy's 6.875% Senior Notes due 2017, GMO's 11.875% Senior Notes due 2012, GMO's 7.95% Senior Notes due 2011 and Great Plains Energy's, KCP&L's and GMO's revolving credit agreements. A decrease in credit ratings could also have an adverse impact on Great Plains Energy's, KCP&L's and GMO's access to capital, the cost of funds, the amounts of collateral required under power supply agreements and Great Plains Energy's ability to provide credit support for its subsidiaries.

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, its secured and unsecured EIRR Bonds Series 2005 totaling $35.9 million and $50.0 million, respectively, and its EIRR Bonds Series 2007A and 2007B totaling $146.5 million, KCP&L has agreed to limits on its ability to issue additional mortgage bonds based on the mortgage bond's credit ratings. See Note 13 to the consolidated financial statements.

The MPSC approval of the GMO acquisition is conditioned on the requirement that any post-acquisition financial effects of a credit downgrade of Great Plains Energy, KCP&L or GMO occurring as a result of the acquisition would be borne by shareholders and not utility customers. The Company also has agreed not to seek rate recovery of GMO interest costs in excess of equivalent investment-grade debt.

Supplemental Capital Requirements and Liquidity Information

The information in the following table is provided to summarize Great Plains Energy's cash obligations and commercial commitments.

Payment due by period	2009	2010	2011	2012	2013	After 2013	Total
Long-term debt				(millions)			
Principal	$ 70.7	$ 1.1	$ 485.4	$ 513.5	$ 12.7	$ 1,428.6	$ 2,512.0
Interest	187.5	182.7	163.1	116.5	86.3	878.9	1,615.0
Lease commitments							
Operating lease	18.3	16.7	15.9	15.6	14.2	167.3	248.0
Capital lease	0.2	0.3	0.3	0.3	0.3	5.4	6.8
Pension plans [(a)]	45.2	(a)	(a)	(a)	(a)	(a)	45.2
Purchase commitments							
Fuel	186.2	170.8	90.6	74.6	84.9	147.7	754.8
Purchased capacity	33.5	29.6	19.9	14.1	13.1	11.7	121.9
Comprehensive Energy Plan	376.2	74.3	-	-	-	-	450.5
Non-regulated natural gas transportation	5.5	5.5	5.0	2.6	2.6	8.2	29.4
Other	70.3	27.4	13.4	7.5	7.3	37.1	163.0
Total contractual commitments [(a)]	$ 993.6	$ 508.4	$ 793.6	$ 744.7	$ 221.4	$ 2,684.9	$ 5,946.6

[(a)] The Company expects to make contributions to the pension plans beyond 2009 but the amounts are not yet determined. Total contractual commitments for 2010, 2011, 2012, 2013, after 2013 and Total do not reflect expected pension plan contributions for periods beyond 2009.

Long-term debt includes current maturities. Great Plains Energy's long-term debt principal excludes $2.2 million of discounts on senior notes. Variable rate interest obligations are based on rates as of December 31, 2008. See Note 13 to the consolidated financial statements for additional information.

Lease commitments end in 2032 and include capital and operating lease obligations. 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 ($18.2 million total) of the amounts included in the table above.

The Company expects to contribute $45.2 million to the pension plans in 2009, of which the majority will be paid by KCP&L. Additional contributions to the plans are expected beyond 2009 in amounts at least sufficient to meet ERISA funding requirements; however, these amounts have not yet been determined.

Fuel commitments consist of commitments for nuclear fuel, coal, coal transportation costs and natural gas. KCP&L and GMO purchase 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 2009 through 2011, $6.9 million in 2012 and $1.6 million in 2013. Comprehensive Energy Plan represents contractual commitments for projects included in KCP&L's Comprehensive Energy Plan including jointly owned units. KCP&L expects to be reimbursed by other owners, including GMO, for their respective share of Iatan No. 2 and environmental retrofit costs included in the Comprehensive Energy Plan contractual commitments. Non-regulated natural gas transportation consists of MPS Merchant's commitments. Other represents individual commitments entered into in the ordinary course of business.

Great Plains Energy adopted the provisions of FIN No. 48, "Accounting for Uncertainty in Income Taxes," an interpretation of SFAS No. 109, "Accounting for Income Taxes" on January 1, 2007. At December 31, 2008, the total liability for unrecognized tax benefits for Great Plains Energy was $97.3 million. Great Plains Energy is

unable to determine reasonably reliable estimates of the period of cash settlement with the respective taxing authorities. See Note 22 to the consolidated financial statements for information regarding the recognition of tax benefits in the next twelve months, which is not expected to have a cash impact.

Great Plains Energy has long-term liabilities recorded on its consolidated balance sheet at December 31, 2008, 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 majority of these agreements guarantee the Company's own future performance, so a liability for the fair value of the obligation is not recorded. At December 31, 2008, Great Plains Energy has provided $1,144.6 million of credit support for certain subsidiaries as follows:

- Great Plains Energy letters of credit totaling $4.0 million to KCP&L counterparties, which expire in 2009,
- Great Plains Energy direct guarantees to GMO counterparties totaling $88.9 million, which expire in 2009,
- Great Plains Energy letters of credit totaling $30.9 million to GMO counterparties, which expire in 2009, and
- Great Plains Energy guarantees of GMO long-term debt totaling $1,020.8 million, which includes debt with maturity dates ranging from 2009-2023.

The following GMO credit facilities also are guaranteed by Great Plains Energy.

- $65 million revolving line of credit dated April 22, 2005, with Union Bank of California, expiring April 22, 2009. This facility is also secured by the accounts receivable from GMO's Missouri regulated utility operations. At December 31, 2008, there was $64.0 million outstanding under this facility.
- $400 million revolving line of credit dated September 23, 2008, with a group of banks, expiring September 23, 2011. At December 31, 2008, there was $110.0 million outstanding under this facility.

None of the guaranteed obligations are subject to default or prepayment as a result of downgrading of GMO securities, although such a downgrading has in the past, and could in the future, increase interest charges under GMO's revolving lines of credit and GMO's 11.875% Senior Notes due 2012 and 7.95% Senior Notes due 2011.

At December 31, 2008, GMO had issued letters of credit totaling $14.4 million as credit support to certain counterparties.

KCP&L is contingently liable for guaranteed energy savings under an agreement with a customer, guaranteeing an aggregate value of approximately $1.9 million over the next two years. A subcontractor would indemnify KCP&L for any payments made by KCP&L under this guarantee.

KCP&L has guarantees related to bond insurance policies for its secured 1992 series EIRR bonds totaling $31.0 million, its Series 1993A and 1993B EIRR bonds totaling $79.5 million, its EIRR Bond Series 2005 totaling $85.9 million and its EIRR Bonds Series 2007A and 2007B totaling $146.5 million. The insurance agreement between KCP&L and the issuer of the bond insurance policies provides for reimbursement by KCP&L for any amounts the insurer pays under the bond insurance policies. As the insurers' credit ratings are below KCP&L's credit ratings, the bonds are rated at KCP&L's credit ratings.

New Accounting Standards
See Note 26 to the consolidated financial statements for information regarding new accounting standards.

KANSAS CITY POWER & LIGHT COMPANY

MANAGEMENT'S NARRATIVE ANALYSIS OF RESULTS OF OPERATIONS

The following discussion of KCP&L results of operations includes KCP&L, an integrated, regulated electric utility and for 2007 and 2006 includes HSS, formerly an unregulated subsidiary of KCP&L, which was transferred from KCP&L to KLT Inc. on January 2, 2008.

The following table summarizes KCP&L's consolidated comparative results of operations.

	2008	2007	2006
		(millions)	
Operating revenues	$ 1,343.0	$ 1,292.7	$ 1,140.4
Fuel	(253.3)	(245.5)	(229.5)
Purchased power	(119.0)	(101.0)	(26.4)
Other operating expenses	(528.3)	(500.6)	(451.5)
Skill set realignment deferral (costs)	-	8.9	(9.3)
Depreciation and amortization	(204.3)	(175.6)	(152.7)
Operating income	238.1	278.9	271.0
Non-operating income and expenses	19.2	4.3	9.6
Interest charges	(72.3)	(67.2)	(61.0)
Income tax expense	(59.8)	(59.3)	(70.3)
Net income	$ 125.2	$ 156.7	$ 149.3

KCP&L Revenues and MWh Sales

	2008	% Change	2007	% Change	2006
Retail revenues			(millions)		
Residential	$ 463.0	7	$ 433.8	13	$ 384.3
Commercial	521.1	6	492.1	11	442.6
Industrial	109.9	3	106.8	7	99.8
Other retail revenues	10.6	8	9.9	12	8.8
Provision for rate refund (excess Missouri wholesale margin)	(2.9)	NM	(1.1)	NA	-
Kansas ECA under recovery	1.6	NA	-	NA	-
Total retail	1,103.3	6	1,041.5	11	935.5
Wholesale revenues	221.5	(5)	234.0	23	190.4
Other revenues	18.2	7	17.2	19	14.5
KCP&L revenues	$ 1,343.0	4	$ 1,292.7	13	$ 1,140.4

	2008	% Change	2007	% Change	2006
Retail MWh sales			(thousands)		
Residential	5,413	(3)	5,597	3	5,413
Commercial	7,704	(0)	7,737	5	7,403
Industrial	2,061	(5)	2,161	1	2,148
Other retail MWh sales	80	(14)	92	8	86
Total retail	15,258	(2)	15,587	4	15,050
Wholesale MWh sales	5,030	(11)	5,635	21	4,676
KCP&L MWh sales	20,288	(4)	21,222	8	19,726

Retail revenues increased $61.8 million in 2008 compared to 2007 primarily due to new retail rates effective January 1, 2008, partially offset by mild summer weather in 2008, with a 27% decrease in cooling degree days.

Retail revenues increased $106.0 million in 2007 compared to 2006 primarily due to new retail rates effective January 1, 2007, growth in the number of customers and higher usage per customer. In addition, favorable weather in 2007, with a 22% increase in heating degree days partially offset by a 5% decrease in cooling degree days, contributed to the increase in retail revenue.

Wholesale revenues decreased $12.5 million in 2008 compared to 2007 due to an 11% decrease in wholesale MWh sales resulting from less generation due to plant outages, partially offset by a 9% increase in the average market price power per MWh to $46.34, primarily due to higher natural gas prices.

Wholesale revenues increased $43.6 million in 2007 compared to 2006 due to a 21% increase in wholesale MWh sales resulting from increased generation due to greater plant availability in the second half of the year.

KCP&L Fuel and Purchased Power

	2008	% Change	2007	% Change	2006
Net MWhs Generated by Fuel Type			(thousands)		
Coal	14,646	(2)	14,894	(1)	15,056
Nuclear	3,994	(18)	4,873	11	4,395
Natural gas and oil	378	(31)	544	(4)	564
Wind	419	38	305	NM	106
Total Generation	19,437	(6)	20,616	2	20,121

KCP&L's coal base load equivalent availability factor for 2008 decreased to 78% from 80% in 2007 and was 83% in 2006.

KCP&L's nuclear unit, Wolf Creek, accounts for approximately 19% of its base load capacity. Wolf Creek's latest refueling outage began on March 20, 2008, and there were several increases in work scope during the outage that extended the restart until May 14, 2008. A primary driver of the work scope increases was modifications to piping systems associated with the emergency core cooling systems. As a result of the outage, the capacity and equivalent availability factor for Wolf Creek decreased to 83% in 2008, compared to 100% for 2007.

Fuel expense increased $7.8 million in 2008 compared to 2007 primarily due to higher coal and coal transportation costs and less nuclear in the fuel mix, which has a lower cost compared to other fuel types. These increases were partially offset by decreased MWhs generated primarily due to lower system requirements.

Fuel expense increased $16.0 million in 2007 compared to 2006 primarily due to higher coal and coal transportation costs and a 2% increase in MWhs generated, excluding wind generation, which has no fuel cost. This increase was partially offset by changes in the fuel mix with more nuclear and less coal and natural gas in the fuel mix.

Purchased power expense increased $18.0 million in 2008 compared to 2007 primarily due to a 26% increase in the average price per MWh as a result of higher natural gas prices. Additionally, an 8% increase in MWh purchases due to the impact of plant outages in the first half of the year increased purchased power expense. These increases were partially offset by $6.5 million in recoveries from a litigation settlement regarding a 2005 transformer failure.

Purchased power expense increased $74.6 million in 2007 compared to 2006 primarily due to a 240% increase in MWh purchases to support increased retail load, the impact of planned and unplanned outages in the first half of 2007 and increased purchases for resale to satisfy firm wholesale MWh sales commitments when it was more economical to purchase power rather than delivering MWhs generated at KCP&L's plants. This increase was slightly offset by a 10% decrease in the average price per MWh.

KCP&L Other Operating Expenses ***(including operating expenses, maintenance, general taxes and other)***
KCP&L's other operating expenses increased $27.7 million in 2008 compared to 2007 primarily due to the following:

- increased plant operations and maintenance expenses of $12.2 million due to plant outages,
- increased employee-related costs of $5.5 million,
- increased property taxes of $3.0 million due to plant additions and increased mill levies and
- increased gross receipts tax expense of $2.1 million due to the increase in revenues.

KCP&L's other operating expenses increased $49.1 million in 2007 compared to 2006 primarily due to the following:

- increased pension expenses of $18.4 million due to the increased level of pension costs in KCP&L's rates effective January 1, 2007,
- increased plant operations and maintenance expenses of $9.7 million primarily due to planned and unplanned outages in the first half of 2007 and the addition of the Spearville Wind Energy Facility in the third quarter of 2006,
- increased transmission expenses of $7.7 million primarily due to increased transmission usage charges as a result of the increased wholesale MWh sales and higher SPP fees,
- increased gross receipts tax expense of $3.6 million due to the increase in revenues,
- increased labor expense of $2.8 million primarily due to filling open positions,
- increased equity compensation expense of $1.9 million and
- increased property taxes of $1.6 million primarily due to increases in mill levies.

Partially offsetting the increase in other operating expenses was decreased incentive compensation expense of $5.7 million.

KCP&L Skill Set Realignment
In 2005 and early 2006, management undertook a process to assess, improve and reposition the skill sets of employees for implementation of KCP&L's 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 2007, KCP&L received authorization from the MPSC and KCC to establish $8.9 million in regulatory assets for these costs and amortize them over five years for the Missouri jurisdictional portion and ten years for the Kansas jurisdictional portion effective with new rates on January 1, 2008.

KCP&L Depreciation and Amortization
KCP&L's depreciation and amortization costs increased $28.7 million in 2008 compared to 2007 primarily due to additional amortization pursuant to rate case orders of $21.7 million combined with normal depreciation activity for capital additions. KCP&L's depreciation and amortization costs increased $22.9 million in 2007 compared to 2006 primarily due to additional amortization pursuant to 2006 rate case orders of $11.9 million and a $4.5 million increase due to wind generation assets placed in service in the third quarter of 2006.

KCP&L Non-operating Income and Expenses
KCP&L's non-operating income and expenses increased $14.9 million in 2008 compared to 2007 primarily due to an increase in the equity component of AFUDC resulting from a higher construction work in progress balance due to KCP&L's Comprehensive Energy Plan projects.

KCP&L Interest Charges
KCP&L's interest charges increased $5.1 million in 2008 compared to 2007 primarily due to interest on $350.0 million of 6.375% unsecured Senior Notes issued in March 2008, partially offset by an increase in the debt component of AFUDC resulting from a higher construction work in progress balance due to KCP&L's Comprehensive Energy Plan projects. KCP&L's interest charges increased $6.2 million in 2007 compared to 2006 due to an increase in short-term borrowings to support expenditures related to KCP&L's Comprehensive Energy Plan.

KCP&L Income Tax Expense
KCP&L's income tax expense increased $0.5 million in 2008 compared to 2007 primarily due to an increase of $20.3 million as a result of an increase in the composite tax rate reflecting the sale of Strategic Energy, mostly offset by decreased pre-tax income and increased wind credits. See Note 22 to the consolidated financial statements for a reconciliation of effective income tax rates for the periods.

KCP&L's income tax expense decreased $11.0 million in 2007 compared to 2006 primarily due to $4.1 million of wind credits and a $7.3 million increase in the allocation of tax benefits from holding company losses pursuant to Great Plains Energy's intercompany tax allocation agreement.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

In the ordinary course of business, Great Plains Energy and 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 risk factors.

Great Plains Energy and 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 ordinary course of business, under the direction and control of an internal risk management committee, Great Plains Energy's and KCP&L's 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. Great Plains Energy and KCP&L 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, and/or failure of underlying transactions that have been hedged to materialize.

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.

Interest Rate Risk

Great Plains Energy and 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, 2008, a hypothetical 10% increase in the interest rates associated with long-term variable rate debt would result in an increase of $0.3 million in interest expense for 2009. Additionally, interest rates impact the fair value of long-term debt. A change in interest rates would impact Great Plains Energy and KCP&L to the extent they redeemed any of their outstanding long-term debt. Great Plains Energy's and KCP&L's book values of long-term debt were above fair value by 15% and 18%, respectively, at December 31, 2008.

KCP&L had $380.2 million of commercial paper outstanding at December 31, 2008. The principal amount of the commercial paper, which will vary during the year, will drive KCP&L's commercial paper interest expense. Assuming that $380.2 million of commercial paper was outstanding for all of 2009, a hypothetical 10% increase in commercial paper rates would result in an increase of $2.0 million in interest expense for 2009.

Commodity Risk

Great Plains Energy and KCP&L 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 $3.1 million decrease in operating income for 2009 related to purchased power. In 2009, approximately 74% of KCP&L's net MWhs generated are expected to be coal-fired. KCP&L currently has almost all of its coal requirements for 2009 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 2009. 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 $0.8 million in fuel expense for 2009. At December 31, 2008, KCP&L had hedged approximately 31% and 3% of its 2009 and 2010, respectively, projected natural gas usage for generation requirements to serve retail load and firm MWh sales. At December 31, 2007, KCP&L had hedged approximately 35% and 4% of its 2008 and 2009, respectively, projected natural gas usage for generation requirements to serve retail load and firm MWh sales. KCP&L's Kansas ECA allows for the recovery of increased fuel and purchased power costs from Kansas retail customers.

In the GMO regulated electric operations in 2008, approximately 55% of the power sold was generated and the remaining 45% was purchased through long-term contracts or in the open market. GMO has a FAC that allows it to adjust retail electric rates based on 95% of the difference between actual fuel and purchased power costs and the amount of fuel and purchased power costs provided in base rates.

Several measures have been taken to mitigate commodity price risk exposure in GMO's electric utility operations. One of these measures is contracting for a diverse supply of coal to meet 82% and 60% of its 2009 and 2010, respectively, native load fuel requirements of coal-fired generation. The price risk associated with natural gas and on-peak spot market purchased power requirements is also mitigated through a hedging plan using New York Mercantile Exchange (NYMEX) futures contracts and options. This is a multi-year hedging plan. As of December 31, 2008, GMO had financial contracts in place to hedge approximately 65% and 4% of expected on-peak natural gas and natural gas equivalent purchased power price exposure for 2009 and 2010, respectively. The mark-to-market value of these contracts at December 31, 2008, was a liability of $6.9 million.

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

Market Risk – MPS Merchant

MPS Merchant is exposed to market risk, including changes in commodity prices. To manage the volatility relating to these exposures, MPS Merchant enters into various derivative transactions in accordance with the risk management policy. The trading portfolios consist of natural gas contracts that are settled by the delivery of the commodity or cash. These contracts take many forms, including futures, forwards, swaps and options. Although MPS Merchant maintains a number of transactions which are fully hedged via back-to-back deals, the business also retains two contractual obligations that are not fully hedged. MPS Merchant is exposed to intra-month natural gas price volatility, with contracts that have a fixed price set at the beginning of each month at which customers have an option to purchase gas from MPS Merchant within the month. Customers typically exercise this option when natural gas prices rise, thereby creating an exposure for MPS Merchant. A hypothetical 10% increase in the daily price of natural gas, versus the First of Month Index (FOM), could result in a $13.7 million

pre-tax decrease in MPS Merchant non-operating income in 2009. MPS Merchant manages this risk daily with monthly and daily swaps. These index-based transactions continue through the year 2017.

Transactions carried out in connection with trading activities that are derivatives under SFAS No. 133 are accounted for under the mark-to-market method of accounting. Under SFAS No. 133, MPS Merchant's energy commodity trading contracts, including physical transactions (mainly gas) and financial instruments, are recorded at fair value. As part of the valuation of the portfolio, Great Plains Energy values the credit risks associated with the financial condition of counterparties and the time value of money. Quoted market prices from published sources or comparable transactions in liquid markets are used to value the contracts. If actively quoted market prices are not available, brokers are contracted or other external sources or comparable transactions are used to obtain current values of the contracts. In addition, the market prices or fair values used in determining the value of the portfolio are best estimates utilizing information such as historical volatility, time value, counterparty credit and the potential impact on market prices of liquidating the positions in an orderly manner over a reasonable period of time under current market conditions. When market prices are not readily available or determinable, certain contracts are recorded at fair value using an alternative approach such as model pricing.

MPS Merchant is also exposed to credit risk. Credit risk is measured by the loss that would be recorded if counterparties failed to perform pursuant to the terms of the contractual obligations less the value of any collateral held. The following table provides information on MPS Merchant's credit exposure to customers at December 31, 2008.

Rating	Exposure Before Credit Collateral	Credit Collateral	Net Exposure
External rating		(millions)	
Investment grade	$ 2.4	$ -	$ 2.4
Non-investment grade	-	-	-
No external rating	41.6	2.0	39.6
Total	$ 44.0	$ 2.0	$ 42.0

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. 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.

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, 2008, 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 $6.0 million reduction in the value of the decommissioning trust funds at December 31, 2008. A hypothetical 10% decrease in equity prices would have resulted in a $3.5 million reduction in the fair value of the equity securities at December 31, 2008. 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.

ITEM 8. CONSOLIDATED FINANCIAL STATEMENTS

GREAT PLAINS ENERGY
Consolidated Statements of Income

Year Ended December 31	2008	2007	2006
Operating Revenues	(millions, except per share amounts)		
Electric revenues	$ 1,670.1	$ 1,292.7	$ 1,140.4
Operating Expenses			
Fuel	311.4	245.5	229.5
Purchased power	208.9	101.0	26.4
Utility operating expenses	377.2	295.8	260.3
Skill set realignment (deferral) costs (Note 10)	-	(8.9)	9.4
Maintenance	122.5	91.7	83.8
Depreciation and amortization	235.0	175.6	152.7
General taxes	128.1	114.4	108.9
Other	12.0	21.1	9.7
Total	1,395.1	1,036.2	880.7
Operating income	275.0	256.5	259.7
Non-operating income	31.9	8.8	15.9
Non-operating expenses	(10.8)	(5.6)	(6.6)
Interest charges	(111.3)	(91.9)	(70.1)
Income from continuing operations before income tax expense, minority interest in subsidiaries and loss from equity investments	184.8	167.8	198.9
Income tax expense	(63.8)	(44.9)	(60.3)
Minority interest in subsidiaries	(0.2)	-	-
Loss from equity investments, net of income taxes	(1.3)	(2.0)	(1.9)
Income from continuing operations	119.5	120.9	136.7
Income (loss) from discontinued operations, net of income taxes (Note 24)	35.0	38.3	(9.1)
Net income	154.5	159.2	127.6
Preferred stock dividend requirements	1.6	1.6	1.6
Earnings available for common shareholders	$ 152.9	$ 157.6	$ 126.0
Average number of basic common shares outstanding	101.1	84.9	78.0
Average number of diluted common shares outstanding	101.2	85.2	78.2
Basic earnings (loss) per common share			
Continuing operations	$ 1.16	$ 1.41	$ 1.74
Discontinued operations	0.35	0.45	(0.12)
Basic earnings per common share	$ 1.51	$ 1.86	$ 1.62
Diluted earnings (loss) per common share			
Continuing operations	$ 1.16	$ 1.40	$ 1.73
Discontinued operations	0.35	0.45	(0.12)
Diluted earnings per common share	$ 1.51	$ 1.85	$ 1.61
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.

Form 10-K

GREAT PLAINS ENERGY
Consolidated Balance Sheets

	December 31	
	2008	2007
ASSETS	(millions, except share amounts)	
Current Assets		
Cash and cash equivalents	**$ 61.1**	$ 24.0
Funds on deposit	**10.8**	-
Receivables, net	**242.3**	166.0
Fuel inventories, at average cost	**87.0**	35.9
Materials and supplies, at average cost	**99.3**	64.0
Deferred refueling outage costs	**12.4**	6.5
Refundable income taxes	**26.0**	16.0
Deferred income taxes	**28.6**	3.6
Assets held for sale (Note 5)	**16.3**	-
Assets of discontinued operations	**-**	487.1
Derivative instruments	**4.8**	0.7
Prepaid expenses	**15.2**	11.0
Total	**603.8**	814.8
Nonutility Property and Investments		
Affordable housing limited partnerships	**13.9**	17.3
Nuclear decommissioning trust fund	**96.9**	110.5
Other	**41.1**	7.5
Total	**151.9**	135.3
Utility Plant, at Original Cost		
Electric	**7,940.8**	5,450.6
Less-accumulated depreciation	**3,582.5**	2,596.9
Net utility plant in service	**4,358.3**	2,853.7
Construction work in progress	**1,659.1**	530.2
Nuclear fuel, net of amortization of $110.8 and $120.2	**63.9**	60.6
Total	**6,081.3**	3,444.5
Deferred Charges and Other Assets		
Regulatory assets	**824.8**	400.1
Goodwill	**156.0**	-
Derivative instruments	**13.0**	-
Other	**38.5**	37.4
Total	**1,032.3**	437.5
Total	**$ 7,869.3**	$ 4,832.1

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

GREAT PLAINS ENERGY
Consolidated Balance Sheets

	December 31 2008	2007
LIABILITIES AND CAPITALIZATION	(millions, except share amounts)	
Current Liabilities		
Notes payable	$ **204.0**	$ 42.0
Commercial paper	**380.2**	365.8
Current maturities of long-term debt	**70.7**	0.3
Accounts payable	**418.0**	241.4
Accrued taxes	**27.7**	19.5
Accrued interest	**72.4**	16.6
Accrued compensation and benefits	**29.7**	22.1
Pension and post-retirement liability	**4.7**	1.3
Liabilities of discontinued operations	**-**	253.4
Derivative instruments	**86.2**	44.4
Other	**43.8**	10.2
Total	**1,337.4**	1,017.0
Deferred Credits and Other Liabilities		
Deferred income taxes	**387.1**	608.0
Deferred tax credits	**105.5**	27.0
Asset retirement obligations	**124.3**	94.5
Pension and post-retirement liability	**445.6**	157.2
Regulatory liabilities	**209.4**	144.1
Other	**113.8**	74.5
Total	**1,385.7**	1,105.3
Capitalization		
Common shareholders' equity		
Common stock-150,000,000 shares authorized without par value		
119,375,923 and 86,325,136 shares issued, stated value	**2,118.4**	1,065.9
Retained earnings	**489.3**	506.9
Treasury stock-120,677 and 90,929 shares, at cost	**(3.6)**	(2.8)
Accumulated other comprehensive loss	**(53.5)**	(2.1)
Total	**2,550.6**	1,567.9
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 (Note 13)	**2,556.6**	1,102.9
Total	**5,146.2**	2,709.8
Commitments and Contingencies (Note 16)		
Total	$ **7,869.3**	$ 4,832.1

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

Form 10-K

GREAT PLAINS ENERGY
Consolidated Statements of Cash Flows

Year Ended December 31	2008	2007	2006
Cash Flows from Operating Activities		(millions)	
Net income	**$ 154.5**	$ 159.2	$ 127.6
Adjustments to reconcile income to net cash from operating activities:			
Depreciation and amortization	**238.3**	183.8	160.5
Amortization of:			
Nuclear fuel	**14.5**	16.8	14.4
Other	**(1.9)**	7.4	9.4
Deferred income taxes, net	**44.1**	23.8	(11.0)
Investment tax credit amortization	**(1.8)**	(1.5)	(1.2)
Loss from equity investments, net of income taxes	**1.3**	2.0	1.9
Fair value impacts from energy contracts - Strategic Energy	**(189.1)**	(52.8)	56.7
Fair value impacts from interest rate hedging	**9.2**	17.9	-
Loss on sale of Strategic Energy	**116.2**	-	-
Other operating activities (Note 3)	**52.6**	(24.4)	(49.4)
Net cash from operating activities	**437.9**	332.2	308.9
Cash Flows from Investing Activities			
Utility capital expenditures	**(1,023.7)**	(511.5)	(475.9)
Allowance for borrowed funds used during construction	**(31.7)**	(14.4)	(5.7)
Purchases of nonutility property	**(1.2)**	(4.5)	(4.2)
Proceeds from sale of Strategic Energy, net of cash sold	**218.8**	-	-
GMO acquisition, net cash received	**271.9**	-	-
Proceeds from sale of assets and investments	**-**	0.1	0.4
Purchases of nuclear decommissioning trust investments	**(49.1)**	(58.0)	(49.7)
Proceeds from nuclear decommissioning trust investments	**45.4**	54.3	46.0
Purchase of additional indirect interest in Strategic Energy	**-**	-	(0.7)
Hawthorn No. 5 partial litigation recoveries	**-**	-	15.8
Other investing activities	**(9.5)**	(13.0)	(1.7)
Net cash from investing activities	**(579.1)**	(547.0)	(475.7)
Cash Flows from Financing Activities			
Issuance of common stock	**15.3**	10.5	153.6
Issuance of long-term debt	**363.4**	495.6	-
Issuance fees	**(5.3)**	(5.7)	(6.2)
Repayment of long-term debt	**(169.9)**	(372.5)	(1.7)
Net change in short-term borrowings	**118.4**	251.4	118.5
Dividends paid	**(172.0)**	(144.5)	(132.6)
Credit facility termination fees	**(12.5)**	-	-
Equity forward settlement	**-**	(12.3)	-
Other financing activities	**(2.2)**	(2.4)	(6.1)
Net cash from financing activities	**135.2**	220.1	125.5
Net Change in Cash and Cash Equivalents	**(6.0)**	5.3	(41.3)
Cash and Cash Equivalents at Beginning of Year (includes $43.1 million, $45.8 million and $76.4 million of cash included in assets of discontinued operations in 2008, 2007 and 2006, respectively)	**67.1**	61.8	103.1
Cash and Cash Equivalents at End of Year (includes $43.1 million and $45.8 million of cash included in assets of discontinued operations in 2007 and 2006, respectively)	**$ 61.1**	$ 67.1	$ 61.8

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

GREAT PLAINS ENERGY

Consolidated Statements of Common Shareholders' Equity

Year Ended December 31	2008		2007		2006	
	Shares	Amount	Shares	Amount	Shares	Amount
			(millions, except share amounts)			
Common Stock						
Beginning balance	**86,325,136**	**$ 1,065.9**	80,405,035	$ 896.8	74,783,824	$ 744.5
Issuance of common stock	**32,962,723**	**1,042.0**	5,571,574	174.1	5,574,385	153.6
Issuance of restricted common stock	**88,064**	**2.3**	348,527	11.1	46,826	1.3
Common stock issuance fees		**-**		-		(5.2)
Equity compensation expense		**5.9**		2.1		2.6
Equity forward settlement		**-**		(12.3)		-
Unearned Compensation						
Issuance of restricted common stock		**(2.3)**		(11.1)		(1.4)
Forfeiture of restricted common stock		**-**		0.2		0.1
Compensation expense recognized		**5.6**		4.8		1.3
Other		**(1.0)**		0.2		-
Ending balance	**119,375,923**	**2,118.4**	86,325,136	1,065.9	80,405,035	896.8
Retained Earnings						
Beginning balance		**506.9**		493.4		498.6
Cumulative effect of a change in accounting principle (Notes 10 and 22)		**(0.1)**		(0.9)		-
Net income		**154.5**		159.2		127.6
Dividends:						
Common stock		**(170.4)**		(142.9)		(131.0)
Preferred stock - at required rates		**(1.6)**		(1.6)		(1.6)
Performance shares		**-**		(0.3)		(0.2)
Ending balance		**489.3**		506.9		493.4
Treasury Stock						
Beginning balance	**(90,929)**	**(2.8)**	(53,499)	(1.6)	(43,376)	(1.3)
Treasury shares acquired	**(39,856)**	**(1.1)**	(37,430)	(1.2)	(11,338)	(0.3)
Treasury shares reissued	**10,108**	**0.3**	-	-	1,215	-
Ending balance	**(120,677)**	**(3.6)**	(90,929)	(2.8)	(53,499)	(1.6)
Accumulated Other Comprehensive Income (Loss)						
Beginning balance		**(2.1)**		(46.7)		(7.7)
Derivative hedging activity, net of tax		**(47.5)**		43.2		(74.7)
Change in unrecognized pension expense, net of tax		**(3.9)**		1.4		-
Minimum pension obligation, net of tax		**-**		-		15.9
Adjustment to initially apply SFAS No. 158, net of tax		**-**		-		(170.2)
Regulatory adjustment		**-**		-		190.0
Ending balance		**(53.5)**		(2.1)		(46.7)
Total Common Shareholders' Equity		**$ 2,550.6**		$ 1,567.9		$ 1,341.9

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	2008	2007	2006
		(millions)	
Net income	**$ 154.5**	$ 159.2	$ 127.6
Other comprehensive income (loss)			
Gain (loss) on derivative hedging instruments	**27.0**	(8.4)	(181.5)
Income taxes	**(12.5)**	2.4	75.0
Net gain (loss) on derivative hedging instruments	**14.5**	(6.0)	(106.5)
Reclassification to expenses, net of tax (Note 20)	**(62.0)**	49.2	31.8
Derivative hedging activity, net of tax	**(47.5)**	43.2	(74.7)
Defined benefit pension plans			
Net gain (loss) arising during period	**(6.7)**	2.0	-
Less: amortization of net gain included in net periodic benefit costs	**0.3**	0.4	-
Prior service costs arising during the period	**-**	(0.3)	-
Less: amortization of prior service costs included in net periodic benefit costs	**0.1**	0.1	-
Income taxes	**2.4**	(0.8)	-
Net change in unrecognized pension expense	**(3.9)**	1.4	-
Change in minimum pension obligation	**-**	-	25.5
Income taxes	**-**	-	(9.6)
Net change in unrecognized pension expense	**-**	-	15.9
Comprehensive income	**$ 103.1**	$ 203.8	$ 68.8

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	2008	2007	2006
Operating Revenues		(millions)	
Electric revenues	**$ 1,343.0**	$ 1,292.7	$ 1,140.4
Operating Expenses			
Fuel	**253.3**	245.5	229.5
Purchased power	**119.0**	101.0	26.4
Operating expenses	**310.0**	295.8	260.3
Skill set realignment (deferral) cost (Note 10)	**-**	(8.9)	9.3
Maintenance	**99.2**	90.9	83.8
Depreciation and amortization	**204.3**	175.6	152.7
General taxes	**118.9**	113.7	108.0
Other	**0.2**	0.2	(0.6)
Total	**1,104.9**	1,013.8	869.4
Operating income	**238.1**	278.9	271.0
Non-operating income	**25.9**	8.0	15.0
Non-operating expenses	**(6.7)**	(3.7)	(5.4)
Interest charges	**(72.3)**	(67.2)	(61.0)
Income before income tax expense	**185.0**	216.0	219.6
Income tax expense	**(59.8)**	(59.3)	(70.3)
Net income	**$ 125.2**	$ 156.7	$ 149.3

The disclosures regarding KCP&L included in the accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

KANSAS CITY POWER & LIGHT COMPANY
Consolidated Balance Sheets

	December 31	
	2008	2007
ASSETS	(millions, except share amounts)	
Current Assets		
Cash and cash equivalents	**$ 5.4**	$ 3.2
Receivables, net	**161.6**	176.4
Fuel inventories, at average cost	**51.7**	35.9
Materials and supplies, at average cost	**68.3**	64.0
Deferred refueling outage costs	**12.4**	6.5
Refundable income taxes	**11.9**	16.6
Deferred income taxes	**4.9**	3.4
Derivative instruments	**0.6**	0.7
Prepaid expenses	**11.8**	10.4
Total	**328.6**	317.1
Nonutility Property and Investments		
Nuclear decommissioning trust fund	**96.9**	110.5
Other	**3.7**	6.2
Total	**100.6**	116.7
Utility Plant, at Original Cost		
Electric	**5,671.4**	5,450.6
Less-accumulated depreciation	**2,738.8**	2,596.9
Net utility plant in service	**2,932.6**	2,853.7
Construction work in progress	**1,148.5**	530.2
Nuclear fuel, net of amortization of $110.8 and $120.2	**63.9**	60.6
Total	**4,145.0**	3,444.5
Deferred Charges and Other Assets		
Regulatory assets	**609.1**	400.1
Other	**45.5**	13.6
Total	**654.6**	413.7
Total	**$ 5,228.8**	$ 4,292.0

The disclosures regarding KCP&L included in the accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

KANSAS CITY POWER & LIGHT COMPANY
Consolidated Balance Sheets

	December 31	
	2008	2007
LIABILITIES AND CAPITALIZATION	(millions, except share amounts)	
Current Liabilities		
Notes payable to Great Plains Energy	**$ -**	$ 0.6
Commercial paper	**380.2**	365.8
Accounts payable	**299.3**	243.4
Accrued taxes	**20.5**	19.0
Accrued interest	**18.1**	9.6
Accrued compensation and benefits	**29.7**	21.6
Pension and post-retirement liability	**1.6**	1.1
Derivative instruments	**80.3**	28.0
Other	**9.1**	8.7
Total	**838.8**	697.8
Deferred Credits and Other Liabilities		
Deferred income taxes	**596.2**	642.2
Deferred tax credits	**99.9**	27.0
Asset retirement obligations	**111.9**	94.5
Pension and post-retirement liability	**410.6**	149.4
Regulatory liabilities	**115.8**	144.1
Other	**56.8**	54.2
Total	**1,391.2**	1,111.4
Capitalization		
Common shareholder's equity		
Common stock-1,000 shares authorized without par value		
1 share issued, stated value	**1,315.6**	1,115.6
Retained earnings	**353.2**	371.3
Accumulated other comprehensive loss	**(46.9)**	(7.5)
Total	**1,621.9**	1,479.4
Long-term debt (Note 13)	**1,376.9**	1,003.4
Total	**2,998.8**	2,482.8
Commitments and Contingencies (Note 16)		
Total	**$ 5,228.8**	$ 4,292.0

The disclosures regarding KCP&L included in the accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

KANSAS CITY POWER & LIGHT COMPANY
Consolidated Statements of Cash Flows

Year Ended December 31	2008	2007	2006
Cash Flows from Operating Activities		(millions)	
Net income	**$ 125.2**	$ 156.7	$ 149.3
Adjustments to reconcile income to net cash from operating activities:			
Depreciation and amortization	**204.3**	175.6	152.7
Amortization of:			
Nuclear fuel	**14.5**	16.8	14.4
Other	**11.1**	4.6	6.6
Deferred income taxes, net	**(7.5)**	19.7	17.4
Investment tax credit amortization	**(1.4)**	(1.5)	(1.2)
Fair value impacts from interest rate hedging	**-**	1.4	-
Other operating activities (Note 3)	**72.8**	(18.5)	(40.0)
Net cash from operating activities	**419.0**	354.8	299.2
Cash Flows from Investing Activities			
Utility capital expenditures	**(810.5)**	(511.5)	(475.9)
Allowance for borrowed funds used during construction	**(23.6)**	(14.4)	(5.7)
Purchases of nonutility property	**-**	(0.1)	(0.1)
Proceeds from sale of assets	**-**	0.1	0.4
Purchases of nuclear decommissioning trust investments	**(49.1)**	(58.0)	(49.7)
Proceeds from nuclear decommissioning trust investments	**45.4**	54.3	46.0
Hawthorn No. 5 partial litigation recoveries	**-**	-	15.8
Other investing activities	**(8.5)**	(7.6)	(0.9)
Net cash from investing activities	**(846.3)**	(537.2)	(470.1)
Cash Flows from Financing Activities			
Issuance of long-term debt	**363.4**	396.1	-
Repayment of long-term debt	**-**	(372.0)	-
Net change in short-term borrowings	**14.4**	209.4	124.6
Dividends paid to Great Plains Energy	**(144.0)**	(140.0)	(89.0)
Equity contribution from Great Plains Energy	**200.0**	94.0	134.6
Issuance fees	**(4.3)**	(3.7)	(0.5)
Net cash from financing activities	**429.5**	183.8	169.7
Net Change in Cash and Cash Equivalents	**2.2**	1.4	(1.2)
Cash and Cash Equivalents at Beginning of Year	**3.2**	1.8	3.0
Cash and Cash Equivalents at End of Year	**$ 5.4**	$ 3.2	$ 1.8

The disclosures regarding KCP&L included in the accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

KANSAS CITY POWER & LIGHT COMPANY
Consolidated Statements of Common Shareholder's Equity

Year Ended December 31	2008		2007		2006	
	Shares	**Amount**	Shares	Amount	Shares	Amount
Common Stock			(millions, except share amounts)			
Beginning balance	**1**	**$ 1,115.6**	1	$ 1,021.6	1	$ 887.0
Equity contribution from Great Plains Energy		**200.0**		94.0		134.6
Ending balance	**1**	**1,315.6**	1	1,115.6	1	1,021.6
Retained Earnings						
Beginning balance		**371.3**		354.8		294.5
Cumulative effect of a change in accounting principle (Note 22)		**-**		(0.2)		-
Net income		**125.2**		156.7		149.3
Transfer of HSS to KLT Inc.		**0.7**		-		-
Dividends:						
Common stock held by Great Plains Energy		**(144.0)**		(140.0)		(89.0)
Ending balance		**353.2**		371.3		354.8
Accumulated Other Comprehensive Income (Loss)						
Beginning balance		**(7.5)**		6.7		(29.9)
Derivative hedging activity, net of tax		**(39.4)**		(14.2)		(0.7)
Minimum pension obligation, net of tax		**-**		-		15.9
Adjustment to initially apply SFAS No. 158, net of tax		**-**		-		(168.6)
Regulatory adjustment		**-**		-		190.0
Ending balance		**(46.9)**		(7.5)		6.7
Total Common Shareholder's Equity		**$ 1,621.9**		$ 1,479.4		$ 1,383.1

The disclosures regarding KCP&L included in the accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

Form 10-K

KANSAS CITY POWER & LIGHT COMPANY
Consolidated Statements of Comprehensive Income

Year Ended December 31	**2008**	2007	2006
		(millions)	
Net income	**$ 125.2**	$ 156.7	$ 149.3
Other comprehensive income (loss)			
Gain (loss) on derivative hedging instruments	**(65.0)**	(22.1)	(0.8)
Income taxes	**25.4**	8.3	0.3
Net gain (loss) on derivative hedging instruments	**(39.6)**	(13.8)	(0.5)
Reclassification to expenses, net of tax (Note 20)	**0.2**	(0.4)	(0.2)
Derivative hedging activity, net of tax	**(39.4)**	(14.2)	(0.7)
Change in minimum pension obligation	**-**	-	25.5
Income taxes	**-**	-	(9.6)
Net gain in minimum pension obligation	**-**	-	15.9
Comprehensive income	**$ 85.8**	$ 142.5	$ 164.5

The disclosures regarding KCP&L included in the accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

GREAT PLAINS ENERGY INCORPORATED
KANSAS CITY POWER & LIGHT COMPANY

Notes to Consolidated Financial Statements

The notes to consolidated financial statements that follow are a combined presentation for Great Plains Energy Incorporated and Kansas City Power & Light Company, both registrants under this filing. The terms "Great Plains Energy," "Company," and "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 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's wholly owned direct subsidiaries with operations or active subsidiaries are as follows:

- KCP&L is an integrated, regulated electric utility that provides electricity to customers primarily in the states of Missouri and Kansas. KCP&L has one wholly owned subsidiary, Kansas City Power & Light Receivables Company (Receivables Company).
- KCP&L Greater Missouri Operations Company (GMO) is an integrated, regulated electric utility that primarily provides electricity to customers in the state of Missouri. GMO also provides regulated steam service to certain customers in the St. Joseph, Missouri area. GMO wholly owns MPS Merchant Services, Inc. (MPS Merchant), which has certain long-term natural gas contracts remaining from its former non-regulated trading operations. Great Plains Energy acquired GMO on July 14, 2008. See Note 2 to the consolidated financial statements for additional information.
- Great Plains Energy Services Incorporated (Services) provides services at cost to Great Plains Energy and its subsidiaries. Effective December 16, 2008, Services employees were transferred to KCP&L. Services continues to obtain certain goods and third-party services for its affiliated companies.
- KLT Inc. is an intermediate holding company that primarily holds investments in affordable housing limited partnerships. KLT Inc. also wholly owns KLT Gas Inc. and Home Service Solutions Inc. (HSS), which have no active operations. KLT Telecom Inc., a wholly owned subsidiary of KLT Inc., was dissolved in December 2008.

On June 2, 2008, Great Plains Energy completed the sale of Strategic Energy, L.L.C. (Strategic Energy). Strategic Energy is accounted for as discontinued operations for all periods presented. See Note 24 for additional information. Great Plains Energy indirectly owned 100% of Strategic Energy through its wholly owned subsidiaries KLT Inc. and Innovative Energy Consultants Inc. (IEC). IEC did not own or operate any assets other than its indirect interest in Strategic Energy. IEC was merged into KLT Inc. in July 2008.

Great Plains Energy's sole reportable business segment is electric utility. Prior to 2008, Great Plains Energy's electric utility segment is the same as the previously reported KCP&L segment. See Note 23 for additional information.

Cash and Cash Equivalents

Cash equivalents consist of highly liquid investments with original maturities of three months or less at acquisition.

Funds on Deposit
Funds on deposit consist primarily of cash provided to counterparties in support of margin requirements related to commodity purchases, commodity swaps and futures contracts. Pursuant to individual contract terms with counterparties, deposit amounts required vary with changes in market prices, credit provisions and various other factors. Interest is earned on most funds on deposit. Great Plains Energy also holds funds on deposit from counterparties in the same manner. These funds are included in other current liabilities on the consolidated balance sheets.

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 – KCP&L's nonutility property and investments 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 and/or valuation models. In addition to KCP&L's investments, Great Plains Energy's nonutility property and investments includes KLT Investments Inc.'s (KLT Investments) affordable housing limited partnerships and GMO's rabbi trust assets. 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. GMO's rabbi trusts related to its Supplemental Executive Retirement Plans (SERP) are recorded at fair value, which are based on quoted market prices of the investments held by the trusts and/or valuation models. The fair values of other various investments are not readily determinable and the investments are therefore stated at cost.

Long-term debt – Fair value is based on quoted market prices, with the incremental borrowing rate for similar debt used to determine fair value if quoted market prices were not available. At December 31, 2008, the book value and fair value of Great Plains Energy's long-term debt was $2.6 billion and $2.2 billion, respectively. At December 31, 2008, the book value and fair value of KCP&L's long-term debt was $1.4 billion and $1.1 billion, respectively. Great Plains Energy's and KCP&L's book values of long-term debt approximated fair values at December 31, 2007.

Derivative instruments – The fair value of derivative instruments is estimated using market quotes, over-the-counter forward price and volatility curves and correlation among fuel prices, net of estimated credit risk.

Pension plans – For financial reporting purposes, the market value of plan assets is the fair value. KCP&L uses a five-year smoothing of assets to determine fair value for regulatory reporting purposes.

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. Great Plains Energy and KCP&L enter into derivative contracts to manage 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. Great Plains Energy and KCP&L may elect the NPNS exception, which requires the effects of the derivative to be recorded when the underlying contract settles. Great Plains Energy and KCP&L account 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. In addition, if a derivative instrument is designated as a cash flow hedge, Great Plains Energy and KCP&L document the

method of determining hedge effectiveness and measuring ineffectiveness. See Note 20 for additional information regarding derivative financial instruments and hedging activities.

Great Plains Energy and KCP&L offset fair value amounts recognized for derivative instruments under master netting arrangements, which include rights to reclaim cash collateral (a receivable), or the obligation to return cash collateral (a payable), pursuant to Financial Accounting Standards Board (FASB) Interpretation (FIN) No. 39, "Offsetting of Amounts Related to Certain Contracts." Great Plains Energy and KCP&L classify cash flows from derivative instruments in the same category as the cash flows from the items being hedged.

Investments in Affordable Housing Limited Partnerships
At December 31, 2008, KLT Investments had $13.9 million of investments in affordable housing limited partnerships. Approximately 87% of these investments were recorded at cost; the equity method was used for the remainder. 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. Tax expense is reduced in the year tax credits are generated. 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, $11.8 million exceed this 5% level but were made before May 19, 1995. Management does not anticipate making additional investments in affordable housing limited partnerships at this time.

On a quarterly basis, KLT Investments compares the cost of those properties accounted for by the cost method to the total of projected residual value of the properties and remaining tax credits to be received. Based on the latest comparison, KLT Investments reduced its investments in affordable housing limited partnerships by $0.4 million, $2.0 million and $1.2 million in 2008, 2007 and 2006, 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 KCP&L's other nonutility property includes land and buildings and improvements (43-45 year life) and is recorded at historical cost, net of accumulated depreciation. Great Plains Energy's other non-utility property also includes office furniture (24-year life).

Utility Plant
Great Plains Energy's and 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 and Accounting for Planned Major Maintenance). When property units are retired or otherwise disposed, the original cost, net of salvage, is charged to accumulated depreciation. Substantially all of KCP&L's 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. Substantially all of GMO's St. Joseph Light & Power division is pledged as collateral for GMO's mortgage bonds under the General Mortgage Indenture and Deed of Trust dated April 1, 1946, as supplemented.

As prescribed by the Federal Energy Regulatory Commission (FERC), Allowance for Funds Used During Construction (AFUDC) is charged to the cost of the plant. AFUDC is included in the rates charged to customers by KCP&L and GMO over the service life of the property. AFUDC equity funds are included as a non-cash item in non-operating income and AFUDC borrowed funds are a reduction of interest charges. The rates used to compute gross AFUDC are compounded semi-annually and averaged 7.1% in 2008, 6.3% in 2007, and 7.8% in 2006 for KCP&L and 4.9% in 2008 for GMO since its acquisition on July 14, 2008.

Great Plains Energy's and KCP&L's balances of utility plant, at original cost, with a range of estimated useful lives are listed in the following table.

Great Plains Energy

December 31	2008	2007
Utility Plant, at original cost	(millions)	
Production (23 - 60 years)	$ 4,171.2	$ 3,197.2
Transmission (27 - 76 years)	655.8	382.8
Distribution (8 - 75 years)	2,588.1	1,542.5
General (5 - 50 years)	525.7	328.1
Total [(a)]	$ 7,940.8	$ 5,450.6

[(a)] Includes $78.4 million and $40.4 million at December 31, 2008 and 2007, respectively, of land and other assets that are not depreciated.

KCP&L

December 31	2008	2007
Utility Plant, at original cost	(millions)	
Production (23 - 60 years)	$ 3,249.8	$ 3,197.2
Transmission (27 - 76 years)	404.7	382.8
Distribution (8 - 75 years)	1,638.6	1,542.5
General (5 - 50 years)	378.3	328.1
Total [(a)]	$ 5,671.4	$ 5,450.6

[(a)] Includes $56.0 million and $40.4 million at December 31, 2008 and 2007, respectively, of land and other assets that are not depreciated.

Depreciation and Amortization

Depreciation and amortization of KCP&L's and GMO'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 3.0% for each of KCP&L and GMO. 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. Great Plains Energy nonutility property annual depreciation rates for 2008, 2007 and 2006 were 7.9%, 12.0% and 11.7%, respectively. KCP&L's nonutility property annual depreciation rates for 2008, 2007 and 2006 were 6.7%, 11.6% and 11.5%, respectively.

Great Plains Energy's depreciation expense was $175.1 million, $140.9 million and $130.7 million for 2008, 2007 and 2006, respectively. KCP&L's depreciation expense was $145.4 million, $140.9 million and $130.7 million for 2008, 2007 and 2006, respectively. Great Plains Energy's and KCP&L's depreciation and amortization expense includes $47.4 million, $25.7 million and $13.8 million for 2008, 2007 and 2006, respectively, of additional amortizations to help maintain cash flow levels pursuant to the Public Service Commission of the State of Missouri (MPSC) and The State Corporation Commission of the State of Kansas (KCC) orders.

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 9 for discussion of AROs including those associated with nuclear plant decommissioning costs.

Deferred Refueling Outage Costs
KCP&L uses the deferral method to account for operations and maintenance expenses incurred in support of Wolf Creek's 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.

Accounting for Planned Major Maintenance
The FASB issued FASB Staff Position (FSP) AUG AIR-1, "Accounting for Planned Major Maintenance Activities" in September 2006. FSP AUG AIR-1 precludes the use of the previously acceptable accrue-in-advance method, which GMO currently follows as allowed by the MPSC. GMO believes that it is probable that the cost of planned major maintenance will be recovered through customer rates charged by the rate-regulated utility operations in advance of such maintenance being performed. Therefore, a regulatory liability was recorded.

Regulatory Matters
Great Plains Energy and KCP&L are subject to the provisions of SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." Pursuant to SFAS No. 71, KCP&L and GMO defer items on the balance sheet resulting from the effects of the ratemaking process, which would not be recorded if KCP&L and GMO were not regulated. See Note 7 for additional information concerning regulatory matters.

Revenue Recognition
Great Plains Energy and KCP&L 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 GMO. Unbilled revenues are recorded for kWh usage in the period following the customers' billing cycle to the end of the month. KCP&L's and GMO's estimate is based on net system kWh usage less actual billed kWhs. KCP&L's and GMO's estimated unbilled kWhs are allocated and priced by regulatory jurisdiction across the rate classes based on actual billing rates.

KCP&L and GMO collect from customers gross receipts taxes levied by state and local governments. These taxes from KCP&L's Missouri customers are recorded gross in operating revenues and general taxes on Great Plains Energy's and KCP&L's statements of income. KCP&L's gross receipts taxes collected from Missouri customers were $45.9 million, $44.7 million and $34.1 million in 2008, 2007 and 2006, respectively. These taxes from KCP&L's Kansas customers and GMO's customers are recorded net in operating revenues on Great Plains Energy's statement of income.

Great Plains Energy and KCP&L record sale and purchase activity on a net basis in wholesale revenue or purchased power when transacting with Regional Transmission Organization (RTO)/Independent System Operator (ISO) markets.

Great Plains Energy and KCP&L collect sales taxes from customers and remit to state and local governments. These taxes are presented on a net basis on Great Plains Energy's and 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 is compared with its carrying value.

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.

In accordance with FIN No. 48, "Accounting for Uncertainty in Income Taxes," an interpretation of SFAS No. 109, "Accounting for Income Taxes," Great Plains Energy and KCP&L recognize tax benefits based on a "more-likely-than-not" recognition threshold. In addition, Great Plains Energy and KCP&L recognize interest accrued related to unrecognized tax benefits in interest expense and penalties in non-operating expenses.

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. KCP&L's income tax provision includes taxes allocated based on its separate company income or loss.

Great Plains Energy and KCP&L have 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 and GMO 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 is determined by dividing income (loss) from 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 from continuing operations.

	2008	2007	2006
Income	(millions, except per share amounts)		
Income from continuing operations	$ 119.5	$ 120.9	$ 136.7
Less: preferred stock dividend requirements	1.6	1.6	1.6
Income available for common stockholders	$ 117.9	$ 119.3	$ 135.1
Common Shares Outstanding			
Average number of common shares outstanding	101.1	84.9	78.0
Add: effect of dilutive securities	0.1	0.3	0.2
Diluted average number of common shares outstanding	101.2	85.2	78.2
Basic EPS from continuing operations	$ 1.16	$ 1.41	$ 1.74
Diluted EPS from continuing operations	$ 1.16	$ 1.40	$ 1.73

The computation of diluted EPS excludes anti-dilutive shares for 2008 of 364,217 performance shares, 530,398 restricted stock shares and 455,469 stock options.

The computation of diluted EPS excludes anti-dilutive shares for 2007 of 128,716 performance shares and 381,451 restricted stock shares. In 2007, there were no anti-dilutive shares applicable to FELINE PRIDES, stock options or a forward sale agreement. FELINE PRIDES settled in the first quarter of 2007 and the forward sale agreement settled in the second quarter of 2007.

The computation of diluted EPS excludes anti-dilutive shares for 2006 of 96,601 performance shares and 116,469 restricted stock shares. Additionally, for 2006, 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.

Dividends Declared

In February 2009, the Board of Directors declared a quarterly dividend of $0.2075 per share on Great Plains Energy's common stock. The common dividend is payable March 20, 2009, to shareholders of record as of February 27, 2009. The Board of Directors also declared regular dividends on Great Plains Energy's preferred stock, payable June 1, 2009, to shareholders of record as of May 8, 2009.

2. GMO ACQUISITION

On July 14, 2008, Great Plains Energy closed its acquisition of GMO. On October 17, 2008, GMO changed its name from Aquila, Inc. to KCP&L Greater Missouri Operations Company (GMO). Prior GMO shareholders received $1.80 in cash plus 0.0856 of a share of Great Plains Energy common stock for each share of GMO common stock. The total purchase price of the acquisition was approximately $1.7 billion. Based on the market price of Great Plains Energy common stock during the period including the two trading days before through the two trading days after February 7, 2007, the date that Great Plains Energy and Aquila announced the acquisition, the fair value of the 32.2 million shares of Great Plains Energy common stock issued was approximately $1.0 billion. Great Plains Energy paid approximately $0.7 billion of cash consideration. Immediately prior to Great Plains Energy's acquisition of GMO, Black Hills Corporation (Black Hills) acquired Aquila's electric utility assets in Colorado and its gas utility assets in Colorado, Kansas, Nebraska and Iowa. Following the closing of the acquisition, Great Plains Energy wholly owns GMO, including its Missouri-based utility operations consisting of the Missouri Public Service and St. Joseph Light & Power divisions. GMO is included in Great Plains Energy's consolidated financial statements beginning as of July 14, 2008.

The transaction received the final required regulatory approval order from the MPSC on July 1, 2008. Certain parties have filed appeals and a motion to stay the order with the Cole County, Missouri, circuit court. The order remains in effect unless reversed by the courts.

The MPSC order provided for the deferral of transition costs to be amortized over a five-year period beginning with the first post-transaction rate cases to the extent that synergy savings exceed amortization. The KCC order approved the deferral of up to $10.0 million of transition cost to be amortized over a five-year period beginning with rates expected to be effective in 2010. At December 31, 2008, Great Plains Energy had $43.1 million of regulatory assets related to transition costs, which included $25.5 million at KCP&L and $17.6 million at GMO.

The acquisition was accounted for under the purchase method of accounting. As a result, the assets and liabilities of GMO were recorded at their estimated fair values as of July 14, 2008. The fair values are preliminary and are subject to adjustment as additional information is obtained, but will be finalized within one year from the acquisition date. The following table shows the preliminary allocation of the purchase price to the assets acquired and liabilities assumed at the date of the acquisition.

	July 14 2008	
Purchase Price Allocation	(millions)	
Cash	$ 677.7	
Common stock (32.2 million shares)	1,026.1	(a)
Stock options (0.5 million options)	2.7	(b)
Transaction costs	35.5	
Total purchase price	1,742.0	
Cash and cash equivalents	949.6	
Receivables	154.1	
Deferred income taxes	501.9	
Other current assets	131.4	
Utility plant, net	1,627.9	
Nonutility property and investments	131.4	
Regulatory assets	176.8	
Other long-term assets	77.4	
Total assets acquired	3,750.5	
Current liabilities	321.5	
Regulatory liabilities	115.9	
Deferred income taxes	246.4	
Long-term debt	1,334.2	
Other long-term liabilities	146.5	
Net assets acquired	1,586.0	
Preliminary goodwill	$ 156.0	

(a) The fair value is based on the average closing price of Great Plains Energy common stock of $31.88, the average during the period beginning two trading days before and ending two trading days after February 7, 2007, the announcement of the acquisition, net of issuing costs.

(b) The fair value is calculated by multiplying the stock options outstanding at July 14, 2008, by the option exchange ratio of 0.1569, calculated as defined in the merger agreement.

Great Plains Energy recorded $156.0 million of preliminary goodwill, all of which is included in the electric utility segment. None of the goodwill is tax deductible. The factors that contributed to a purchase price that resulted in goodwill were strategic considerations and significant cost savings and synergies including: expanded regulated electric utility business; adjacent regulated electric utility territories; increased GMO financial strength and flexibility; improved reliability and customer service and disposition of non-strategic gas operations. Changes to the initial allocation of the purchase price consisted of additional fair value adjustments to certain real estate properties, primarily offset by net operating loss valuation allowance adjustments.

In connection with the acquisition of GMO, Great Plains Energy recognized an intangible liability of approximately $25.9 million associated with the remaining natural gas contracts of MPS Merchant, GMO's non-regulated former wholesale energy trading operations, that do not qualify as derivatives under SFAS No. 133. Great Plains Energy recognized $0.6 million of amortization in 2008. The net carrying amount of this intangible liability was approximately $25.3 million at December 31, 2008, and is reported as a component of other liabilities on Great Plains Energy's consolidated balance sheet. The balance will be amortized into expense through March 31, 2017, based on volumes of the underlying contracts. Amortization is estimated at $4.4 million, $4.4 million, $5.4 million, $2.8 million and $2.0 million for 2009, 2010, 2011, 2012 and 2013, respectively.

The following table provides unaudited pro forma results of operations for Great Plains Energy for December 31, 2008, as if the acquisition had occurred January 1, 2008. The table also provides unaudited pro forma results of operations for Great Plains Energy for December 31, 2007, as if the acquisition had occurred January 1, 2007. Pro forma results are not necessarily indicative of the actual results that would have resulted had the acquisition actually occurred on January 1, 2008 or January 1, 2007.

	December 31	
	2008	2007
	(millions, except per share amounts)	
Operating revenues	$ 2,013.6	$ 1,944.3
Income from continuing operations	$ 121.1	$ 119.2
Net income	$ 156.1	$ 157.5
Earnings available for common shareholders	$ 154.5	$ 155.9
Basic and diluted earnings per common share from continuing operations	$ 1.18	$ 1.00
Basic and diluted earnings per common share	$ 1.53	$ 1.33

3. SUPPLEMENTAL CASH FLOW INFORMATION

Great Plains Energy Other Operating Activities

	2008	2007	2006
Cash flows affected by changes in:		(millions)	
Receivables	$ 61.9	$ (80.0)	$ (80.8)
Fuel inventories	(16.7)	(9.3)	(10.7)
Materials and supplies	(3.7)	(4.2)	(2.8)
Accounts payable	56.2	43.3	68.1
Accrued taxes	73.2	17.3	(22.5)
Accrued interest	17.8	(0.7)	0.7
Deferred refueling outage costs	(5.9)	7.4	(5.9)
Accrued plant maintenance costs	2.1	-	-
Pension and post-retirement benefit obligations	3.1	17.6	3.6
Allowance for equity funds used during construction	(24.2)	(2.5)	(5.0)
Deferred acquisition costs	(15.8)	(18.3)	(2.8)
Proceeds from the sale of SO_2 emission allowances	0.4	24.0	0.8
T-Lock settlement	(41.2)	(4.5)	-
Fuel adjustment clauses	(18.0)	-	-
Proceeds from forward starting swaps	-	3.3	-
Other	(36.6)	(17.8)	7.9
Total other operating activities	$ 52.6	$ (24.4)	$ (49.4)
Cash paid during the period:			
Interest	$ 95.0	$ 91.8	$ 67.7
Income taxes	$ 27.1	$ 33.6	$ 77.7
Non-cash investing activities:			
Liabilities assumed for capital expenditures	$ 104.7	$ 72.5	$ 38.7

KCP&L Other Operating Activities

	2008	2007	2006
Cash flows affected by changes in:		(millions)	
Receivables	$ 50.9	$ (60.0)	$ (44.7)
Fuel inventories	(16.0)	(9.3)	(10.7)
Materials and supplies	(4.3)	(4.2)	(2.8)
Accounts payable	57.3	20.6	52.4
Accrued taxes	81.3	5.9	(16.5)
Accrued interest	8.5	(2.9)	0.9
Deferred refueling outage costs	(5.9)	7.4	(5.9)
Pension and post-retirement benefit obligations	(5.1)	15.4	0.7
Allowance for equity funds used during construction	(22.5)	(2.5)	(5.0)
Proceeds from the sale of SO_2 emission allowances	0.4	24.0	0.8
T-Lock settlement	(41.2)	-	-
Kansas Energy Cost Adjustment	(1.6)	-	-
Proceeds from forward starting swaps	-	3.3	-
Other	(29.0)	(16.2)	(9.2)
Total other operating activities	$ 72.8	$ (18.5)	$ (40.0)
Cash paid during the period:			
Interest	$ 63.0	$ 68.3	$ 57.9
Income taxes	$ 23.5	$ 39.8	$ 70.9
Non-cash investing activities:			
Liabilities assumed for capital expenditures	$ 90.8	$ 72.4	$ 38.2

Significant Non-Cash Items
On July 14, 2008, Great Plains Energy closed its acquisition of GMO. The total purchase price of the acquisition was approximately $1.7 billion. The fair value of the 32.2 million shares of Great Plains Energy common stock issued was approximately $1.0 billion. Great Plains Energy paid approximately $0.7 billion of cash consideration. See Note 2 for additional information.

In May 2008, KCP&L's Series 2008 EIRR bonds totaling $23.4 million maturing in 2038 were issued. The proceeds were deposited with a trustee. At December 31, 2008, KCP&L had received $13.4 million in cash proceeds and had a $10.0 million short-term receivable for the proceeds that were deposited with the trustee.

In 2008, KCP&L recorded a $12.6 million net increase in AROs, consisting of a $14.2 million increase as a result of changes in cost estimates and timing used to compute the present value of asbestos AROs for KCP&L's generating stations, with a corresponding increase in net utility plant and a decrease of $1.6 million resulting from an update to the cost estimates to decommission Wolf Creek, with a corresponding increase in regulatory liabilities. This activity had no impact on Great Plains Energy's or KCP&L's 2008 cash flows. See Note 9 for additional information.

In February 2007, Great Plains Energy issued 5.2 million shares of common stock in satisfaction of the FELINE PRIDES stock purchase contracts and the redemption of the $163.6 million FELINE PRIDES Senior Notes.

4. RECEIVABLES

Great Plains Energy's and KCP&L's receivables are detailed in the following table.

	December 31	
	2008	2007
KCP&L	(millions)	
Customer accounts receivable - billed	$ 15.5	$ 7.6
Customer accounts receivable - unbilled	41.7	37.7
Allowance for doubtful accounts	(1.2)	(1.2)
Intercompany receivables	28.5	10.5
Other receivables	77.1	121.8
Total	$ 161.6	$ 176.4
Great Plains Energy		
Customer accounts receivable - billed	$ 61.3	$ 7.6
Customer accounts receivable - unbilled	69.9	37.7
Allowance for doubtful accounts	(3.5)	(1.2)
Other receivables	143.1	132.4
Elimination of KCP&L intercompany receivables	(28.5)	(10.5)
Total	$ 242.3	$ 166.0

Great Plains Energy's and KCP&L's other receivables at December 31, 2008 and 2007, consisted primarily of receivables from partners in jointly owned electric utility plants and wholesale sales receivables.

Sale of Accounts Receivable – KCP&L

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. In accordance with SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishment of Liabilities," the sales under these agreements qualify as a sale under which the creditors of Receivables Company are entitled to be satisfied out of the assets of Receivables Company prior to any value being returned to KCP&L or its creditors. Accounts receivable sold by Receivables Company to the outside investor under this revolving agreement totaled $70.0 million at December 31, 2008 and 2007. 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 1.3% to 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. The agreement expires July 2009, and KCP&L intends to renew the agreement.

Information regarding KCP&L's sale of accounts receivable to Receivables Company is reflected in the following tables.

2008	KCP&L	Receivables Company	Consolidated KCP&L
		(millions)	
Receivables (sold) purchased	$ (1,147.3)	$ 1,147.3	$ -
Gain (loss) on sale of accounts receivable [a]	(14.5)	14.4	(0.1)
Servicing fees	1.7	(1.7)	-
Fees to outside investor	-	(2.6)	(2.6)
Cash flows during the period			
Cash from customers transferred to Receivables Company	(1,142.1)	1,142.1	-
Cash paid to KCP&L for receivables purchased	1,127.8	(1,127.8)	-
Servicing fees	1.7	(1.7)	-
Interest on intercompany note	1.9	(1.9)	-

2007	KCP&L	Receivables Company	Consolidated KCP&L
		(millions)	
Receivables (sold) purchased	$ (1,082.6)	$ 1,082.6	$ -
Gain (loss) on sale of accounts receivable [a]	(13.3)	13.0	(0.3)
Servicing fees	3.1	(3.1)	-
Fees to outside investor	-	(4.1)	(4.1)
Cash flows during the period			
Cash from customers transferred to Receivables Company	(1,078.8)	1,078.8	-
Cash paid to KCP&L for receivables purchased	1,065.9	(1,065.9)	-
Servicing fees	3.1	(3.1)	-
Interest on intercompany note	3.1	(3.1)	-

[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.

5. ASSETS HELD FOR SALE

On July 14, 2008, Great Plains Energy closed its acquisition of GMO. GMO has several real estate properties that will not be used. As a result, these real estate properties are available for immediate sale in their present condition and management is actively marketing these properties. The carrying amounts for these assets are presented at fair value less estimated selling cost and are included in assets held for sale on Great Plains Energy's balance sheet. Of the $16.3 million of assets held for sale at December 31, 2008, $11.9 million is included in the electric utility segment and the remaining $4.4 million is included in the other category.

6. NUCLEAR PLANT

KCP&L owns 47% of Wolf Creek, its only nuclear generating unit. Wolf Creek is regulated by the Nuclear Regulatory Commission (NRC), with respect to licensing, operations and safety-related requirements.

Spent Nuclear Fuel and High-Level 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 kWh of net nuclear generation delivered and sold for the future disposal of spent nuclear fuel. These disposal costs are charged to fuel expense. On June 3, 2008, the DOE filed with the NRC an application for authority to construct a national repository for the disposal of spent nuclear fuel and high-level radioactive waste at Yucca Mountain, Nevada. On September 8, 2008, the NRC found the application sufficiently complete to undergo a technical licensing review and therefore docketed the application. The DOE has indicated that, assuming the NRC approves the application in the next three to four years, the DOE could be ready to begin accepting spent nuclear fuel by 2020, but only if Congress provides adequate funding for the project. 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, and believes it will be able to expand on-site storage as needed past 2025. If the DOE meets its revised timetable for accepting spent fuel for disposal by 2020, management expects that the DOE could begin accepting some of Wolf Creek's spent fuel by 2028. Management can make no assurance that the DOE will meet its revised timetable and will continue to monitor this activity. See Note 17 for a related legal proceeding.

Low-Level Radioactive Waste

Wolf Creek disposes of most of its low-level radioactive waste (Class A waste) at an existing third-party repository in Utah. Wolf Creek previously disposed of the remainder of its low-level radioactive waste (Class B and Class C waste, which is higher in radioactivity but much lower in volume) at a disposal site in Barnwell, South Carolina. However, effective July 1, 2008, the state of South Carolina no longer accepts low-level radioactive waste at Barnwell, except for waste from generators located in South Carolina, Connecticut, and New Jersey. Wolf Creek has storage capacity on site for about four years generation of Class B and Class C waste. Management expects that the site located in Utah will remain available to Wolf Creek for disposal of its low-level radioactive waste. Should disposal capability become unavailable, management believes Wolf Creek will be able to store its low-level radioactive waste in an on-site facility and that a temporary loss of low-level radioactive waste disposal capability would not affect Wolf Creek's continued operation.

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 August 2008 and is the basis for the current cost of decommissioning estimates in the following table. KCP&L did not request an increase in funding levels and estimated that the current annual contribution will be adequate to cover the decommissioning costs of Wolf Creek.

	Total Station	KCP&L's 47% Share
	(millions)	
Current cost of decommissioning (in 2008 dollars)	$ 594	$ 279
Future cost of decommissioning (in 2045-2053 dollars) [a]	3,335	1,568
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 through 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. 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, while there can be no assurances, management believes a rate increase would be allowed, ensuring full recovery of decommissioning costs over the remaining life of the unit.

The following table summarizes the change in Great Plains Energy's and KCP&L's decommissioning trust fund.

December 31	2008	2007
Decommissioning Trust	(millions)	
Beginning balance	$ 110.5	$ 104.1
Contributions	3.7	3.7
Earned income, net of fees	3.3	1.6
Net realized gains/(losses)	(8.2)	3.3
Net unrealized losses	(12.4)	(2.2)
Ending balance	$ 96.9	$ 110.5

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			
	2008		2007	
	Fair Value	Unrealized Gains/(Losses)	Fair Value	Unrealized Gains
	(millions)			
Equity securities	$ 34.6	$ (5.3)	$ 51.6	$ 7.6
Debt securities	59.9	1.0	55.9	0.5
Other	2.4	-	3.0	-
Total	$ 96.9	$ (4.3)	$ 110.5	$ 8.1

The weighted average maturity of debt securities held by the trust at December 31, 2008 and 2007, was approximately 7.0 years. The costs of securities sold are determined on the basis of specific identification. The following table summarizes the gains and losses from the sale of securities by the nuclear decommissioning trust fund.

	2008	2007	2006
		(millions)	
Realized Gains	$ 2.7	$ 6.1	$ 5.0
Realized Losses	(10.9)	(2.8)	(0.9)

Nuclear 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. The nuclear property insurance programs subscribed to by members of the nuclear power generating industry include industry aggregate limits for acts of terrorism and related losses, including replacement power costs. There is no industry aggregate limit for liability claims, regardless of the number of 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 plus any recoverable reinsurance are the maximum amount to be paid to members who sustain losses or damages from these types of terrorist acts. In addition, industry-wide retrospective assessment programs (discussed below) can apply once these insurance programs have been exhausted.

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.

Nuclear 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 $12.5 billion. This limit of liability consists of the maximum available commercial insurance of $0.3 billion and the remaining $12.2 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 $117.5 million ($55.2 million, KCP&L's 47% share) per incident at any commercial reactor in the country, payable at no more than $17.5 million ($8.2

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.

Nuclear Property 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 $23.3 million ($11.0 million, KCP&L's 47% share) per policy year.

7. REGULATORY MATTERS

Regulatory Proceedings

On September 5, 2008, KCP&L filed requests for annual rate increases with the MPSC and KCC and GMO filed requests for annual rate increases with the MPSC, with new rates expected to be effective in the third quarter of 2009. The following table summarizes the requests.

		Annual Revenue Increase				
Rate Jurisdiction [a]	File Date	Traditional [b]	Additional Amortization	Total [c]	Return on Equity	Rate-making Equity Ratio
			(millions)			
GMO (MPS)	9/5/2008	$ 66.0	$ -	$ 66.0	10.75%	53.82%
GMO (L&P)	9/5/2008	17.1	-	17.1	10.75%	53.82%
GMO (Steam)	9/5/2008	1.3	-	1.3	10.75%	53.82%
KCP&L (MO)	9/5/2008	86.4	15.1	101.5	10.75%	53.82%
KCP&L (KS)	9/5/2008	60.4	11.2	71.6	10.75%	55.39%
Total		$ 231.2	$ 26.3	$ 257.5		

[a] Rate Jurisdiction Areas:
GMO (MPS): Represents the area served by GMO's Missouri Public Service division
GMO (L&P): Represents the area served by GMO's St. Joseph Light & Power division
GMO (Steam): GMO steam customers in the St. Joseph, Missouri, area
KCP&L (MO): KCP&L Missouri customers (not in former Aquila service territory)
KCP&L (KS): KCP&L Kansas customers

[b] The amounts in this column reflect the revenue requirements calculated using the traditional rate case methodologies, which exclude additional amortization amounts to help maintain cash flow levels

[c] Excludes amounts recovered through KCP&L's Kansas ECA and most of GMO's FAC and QCA

In February 2009, the MPSC and KCC staffs filed their respective testimony regarding the requests for annual rate increases filed by KCP&L and GMO. The following table details the rate increases recommended by the MPSC and KCC staffs by KCP&L and GMO jurisdiction.

	Annual Revenue Increase				
Rate Jurisdiction	Traditional	Additional Amortization	Total	Return on Equity	Rate-making Equity Ratio
		(millions)			
GMO (MPS) [a]	$ 46.0	$ -	$ 46.0	9.75%	51.03%
GMO (L&P) [a]	22.8	-	22.8	9.75%	51.03%
GMO (Steam) [a]	1.0	-	1.0	9.75%	51.03%
KCP&L (MO) [a]	45.2	[b]	45.2	9.75%	50.65%
KCP&L (KS)	42.6	11.2	53.8	11.40%	50.76%
Total	$ 157.6	$ 11.2	$ 168.8		

[a] Annual revenue increase and return on equity based on the mid-point of MPSC staff's return on equity range.

[b] Amount not included in the MPSC staff's February 2009 testimony, but will be included in the second quarter 2009 true up.

KCP&L's Comprehensive Energy Plan and Collaboration Agreement

Current estimates for KCP&L's Comprehensive Energy Plan Iatan No. 1 and Iatan No. 2 projects are as follows:

- In the first quarter of 2009, KCP&L completed construction of the Iatan No. 1 environmental project and Iatan common facilities. KCP&L's share of the total projected cost excluding AFUDC is in the table below and includes KCP&L's 70% share of costs directly associated with Iatan No. 1 and KCP&L's 61% share of estimated costs of Iatan common facilities that will be used by both Iatan No. 1 and Iatan No. 2. The vast majority of the common facilities costs were previously included in the Iatan No. 2 cost estimates disclosed in the Company's quarterly reports on Form 10-Q during 2008. Great Plains Energy's total share of Iatan No. 1 is 88%, which consists of KCP&L's 70% share and GMO's 18% share. Great Plains Energy's total share of Iatan common facilities is 79%, which consists of KCP&L's 61% share and GMO's 18% share. Great Plains Energy's share of the total projected cost excluding AFUDC of the Iatan No. 1 environmental project and Iatan common facilities is in the table below.
- Iatan No. 1 has been off-line for a scheduled outage since mid-October 2008 for a unit overhaul and to tie in the environmental equipment. Iatan No. 1 was originally scheduled to be back on-line in February 2009, but, during start-up, a high level of vibration was experienced. Repairs to the turbine could delay the in-service date of Iatan No. 1, by up to two months. Management believes that a delay of that duration could still be accommodated in the current KCP&L and GMO rate cases; however, there could be a corresponding delay in the effective date of the MPSC rate orders from the current August 5, 2009, date. Management is unable to predict the length of such a delay, if any.
- KCP&L's approximate 55% share of the total projected cost of Iatan No. 2 excluding AFUDC is in the table below. The reduction in the range from the previously disclosed Iatan No. 2 cost estimates reflects removal of costs for common facilities discussed above. These costs were previously included in the Iatan No. 2 cost estimates disclosed in the Company's quarterly reports on Form 10-Q during 2008. Great Plains Energy's total share of Iatan No. 2 is 73%, which consists of KCP&L's 55% share and GMO's 18% share. Great Plains Energy's 73% share of the total projected cost excluding AFUDC of Iatan No. 2 is in the table below. The anticipated in-service date for Iatan No. 2 is the summer of 2010.

KCP&L

	Current Estimate Range	Previous Estimate Range	Change
		(millions)	
Iatan No. 1 (70% share)	$ 242 - $ 262	$ 330 - $ 350	$ (88) - $ (88)
Iatan No. 2 (55% share)	847 - 904	994 - 1,051	(147) - (147)
Iatan Common (61% share)	235 - 235	- - -	235 - 235
Total	$ 1,324 - $ 1,401	$ 1,324 - $ 1,401	$ - - $ -

Great Plains Energy

	Current Estimate Range	Previous Estimate Range	Change
		(millions)	
Iatan No. 1 (88% share)	$ 307 - $ 332	$ 415 - $ 440	$ (108) - $ (108)
Iatan No. 2 (73% share)	1,125 - 1,201	1,321 - 1,397	(196) - (196)
Iatan Common (79% share)	304 - 304	- - -	304 - 304
Total	$ 1,736 - $ 1,837	$ 1,736 - $ 1,837	$ - - $ -

In March 2007, KCP&L, the Sierra Club and the Concerned Citizens of Platte County entered into a Collaboration Agreement that resolved disputes among the parties. KCP&L agreed to pursue a set of initiatives including energy efficiency, additional wind generation, lower emission permit levels at its Iatan and LaCygne generating stations and other initiatives designed to offset CO_2 emissions. KCP&L will address these matters in its future integrated energy resource plan in collaboration with stakeholders. Full implementation of the terms of the agreement will necessitate approval from the appropriate authorities, as some of the initiatives in the agreement require either enabling legislation or regulatory approval.

In the Collaboration Agreement, KCP&L agreed to use its best efforts to install emission control technologies to reduce certain emissions from the LaCygne Station prior to the required compliance date under the Environmental Protection Agency (EPA) best available retrofit technology rule (BART), but in no event later than June 1, 2015. KCP&L further agreed to issue requests for proposal for the equipment required to comply with BART by December 31, 2008, requesting that construction commence by December 31, 2010, and has done so. KCP&L's Comprehensive Energy Plan includes a project to install the required emission control technologies at LaCygne No. 1 for completion in 2009. Demand for environmental equipment has increased substantially leading to extremely long lead times for equipment. As a result, the LaCygne No. 1 project will not be completed in 2009. Since KCP&L must also install such emission control technologies at LaCygne No. 2, management continues to evaluate the timing of the required environmental upgrades for both LaCygne Nos. 1 and 2. Management has selected an owner's engineer for the LaCygne Station environmental project and will focus on the project design in 2009.

KCP&L also agreed in the Collaboration Agreement to pursue increasing its wind generation capacity by 100MW by the end of 2010. KCP&L had entered into agreements to acquire 100MW of wind generation for approximately $215 million. In October 2008, KCP&L provided notice to terminate this contract and began discussions with the developer to explore alternatives. Subsequently, KCP&L entered into new agreements with the developer in February 2009. The developer has assigned to KCP&L its contract with the wind turbine manufacturer to purchase thirty-two turbines for a purchase price of approximately $68 million, plus approximately $17 million to be paid by KCP&L to the developer for various third party development and assignment costs. KCP&L's deposit of approximately $42 million under the original, terminated agreement will be applied to the purchase price. KCP&L and the developer also entered into an agreement for the construction of a thirty-five turbine project, with a May 31, 2010, estimated project completion date, for an approximate price of $118 million. This construction agreement contains an absolute and unconditional option for KCP&L to terminate the agreement on or before September 30, 2009, for an upfront payment of $7.5 million, which will be applied to the price if the option is not exercised by KCP&L. Also in the Collaboration Agreement, KCP&L agreed to pursue an additional 300MW of wind generation capacity by the end of 2012, subject to regulatory approval.

KCP&L Missouri 2006 Rate Case Appeal

On December 21, 2006, the MPSC issued an order approving an approximate $51 million increase in annual revenues effective January 1, 2007. Appeals of the MPSC order 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, seeking to set aside or remand the order to the MPSC. The court affirmed the MPSC's decision in December 2007 and that decision was appealed by Trigen-Kansas City Energy Corporation. Trigen-Kansas City Energy Corporation withdrew its appeal on June 3, 2008.

GMO Missouri 2007 Rate Case Appeal
Appeals of the MPSC order were filed in July and August of 2007 with the Circuit Court of Cole County, Missouri, by the Office of Public Counsel, AG Processing, Sedalia Industrial Energy Users' Association and AARP seeking to set aside or remand the order of the MPSC. In February 2009, the Circuit Court affirmed the MPSC order. This decision may be appealed. The order remains in effect unless reversed by the courts.

GMO RTO Application
GMO's application to transfer functional control of its transmission system to the Midwest Independent Transmission System Operator, Inc. (MISO) RTO was denied by the MPSC in October 2008. In December 2008, GMO submitted a request to FERC to withdraw from MISO based on this MPSC denial. GMO and MISO are negotiating an agreement regarding this exit under which GMO would pay an insignificant amount of exit fees to MISO. This agreement is awaiting FERC approval.

In November 2008, GMO requested MPSC authorization to transfer functional control of its transmission system to the Southwest Power Pool, Inc. (SPP). On February 4, 2009, the MPSC approved a Stipulation and Agreement between GMO and several parties, thereby granting GMO the authorized request.

Great Plains Energy's Acquisition of GMO
See Note 2 for a discussion of the pending appeals of the MPSC order authorizing the acquisition.

Regulatory Assets and Liabilities
Great Plains Energy and KCP&L are subject to the provisions of SFAS No. 71 and have recorded assets and liabilities on its balance sheet resulting from the effects of the ratemaking process, which would not otherwise be recorded under Generally Accepted Accounting Principles (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 or GMO's regulators that may require refunds to customers; amounts provided in current rates that are intended to recover costs that are expected to be incurred in the future for which KCP&L and GMO remain accountable; or 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 and GMO's rate case filings; decisions in other regulatory proceedings, including decisions related to other companies that establish precedent on matters applicable to KCP&L or GMO; 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 and GMO'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 and GMO'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.

Great Plains Energy's and KCP&L's regulatory assets and liabilities are detailed in the following tables.

December 31, 2008	KCP&L		GMO		Great Plains Energy
Regulatory Assets			(millions)		
Taxes recoverable through future rates	$ 71.6		$ 46.8		$ 118.4
Loss on reacquired debt	5.7	(a)	0.3	(a)	6.0
Cost of removal	9.6		-		9.6
Asset retirement obligations	21.1		12.0		33.1
SFAS No. 158 pension and post-retirement costs	355.8	(b)	-		355.8
Other pension and post-retirement costs	79.8	(c)	63.0	(c)	142.8
Environmental remediation	-		2.0	(g)	2.0
Deferred customer programs	22.6	(d)	0.4		23.0
Rate case expenses	2.9	(e)	0.6	(e)	3.5
Skill set realignment costs	7.5	(f)	-		7.5
Under-recovery of energy costs	1.6	(g)	52.0	(g)	53.6
Acquisition transition costs	25.5		17.6		43.1
St. Joseph Light & Power acquisition	-		3.6	(g)	3.6
Storm damage	-		6.4	(g)	6.4
Other	5.4	(h)	11.0	(h)	16.4
Total	$ 609.1		$ 215.7		$ 824.8
Regulatory Liabilities					
Emission allowances	$ 86.5		$ 1.0		$ 87.5
Asset retirement obligations	22.7		-		22.7
Pension	-		25.0		25.0
Cost of removal	-		58.1	(i)	58.1
Other	6.6		9.5		16.1
Total	$ 115.8		$ 93.6		$ 209.4

December 31, 2007	KCP&L and Great Plains Energy	
Regulatory Assets	(millions)	
Taxes recoverable through future rates	$ 66.5	
Loss on reacquired debt	5.9	
Change in depreciable life of Wolf Creek	45.4	(j)
Cost of removal	8.4	
Asset retirement obligations	18.5	
SFAS No. 158 pension and post-retirement costs	146.8	
Other pension and post-retirement costs	76.1	
Deferred customer programs	11.6	
Rate case expenses	3.2	
Skill set realignment costs	8.9	
Other	8.8	
Total	$ 400.1	
Regulatory Liabilities		
Emission allowances	$ 87.5	
Asset retirement obligations	39.4	
Additional Wolf Creek amortization (Missouri)	14.6	(j)
Other	2.6	
Total	$ 144.1	

(a) Amortized over the life of the related new debt issuances or the remaining lives of the old debt issuances if no new debt was issued.
(b) KCP&L's regulatory asset for SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans," pension and post-retirement costs at December 31, 2008, is more than offset by related liabilities, not included in rate base.
(c) KCP&L's regulatory asset for other pension and post-retirement costs at December 31, 2008, includes $56.3 million representing pension settlements and financial and regulatory accounting method differences not included in rate base. The pension settlements, totaling $9.9 million, are being amortized over a five-year period, which began January 1, 2008. The accounting method difference will be eliminated over the life of the pension plans. GMO's regulatory asset for other pension and post-retirement costs at December 31, 2008, includes $45.3 million representing financial and regulatory accounting method differences not included in rate base that will be eliminated over the life of the pension plans.
(d) $8.7 million not included in rate base.
(e) $2.2 million and $0.6 million at KCP&L and GMO, respectively, not included in rate base and amortized over various periods.
(f) $3.6 million not included in rate base and amortized through 2017.
(g) Not included in rate base.
(h) Certain insignificant items are not included in rate base and amortized over various periods.
(i) Estimated cumulative net provision for future removal costs.
(j) Consistent with current ratemaking treatment in Missouri and Kansas, KCP&L reclassified the regulatory assets for change in depreciable life of Wolf Creek of $45.4 million (Missouri and Kansas) and the regulatory liability for additional Wolf Creek amortization (Missouri) of $14.6 million at December 31, 2007, to accumulated depreciation in the second quarter of 2008.

8. INTANGIBLE ASSETS

Great Plains Energy's and KCP&L's intangible assets are detailed in the following table.

	December 31, 2008		December 31, 2007	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
	(millions)			
KCP&L				
Computer software [(a)]	$ 136.7	$ (95.4)	$ 111.9	$ (84.7)
Great Plains Energy				
Computer software [(a)]	$ 160.5	$ (106.0)	$ 112.4	$ (84.9)
Transmission line upgrades [(a)]	22.1	(3.3)	-	-
Organization start-up costs [(a)]	0.1	-	-	-

[(a)] Included in electric utility plant on the consolidated balance sheets.

9. 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 2008, KCP&L recorded a $1.6 million reduction to its ARO to decommission Wolf Creek, which reflects a 2008 update to the decommissioning study cost estimates.

Asbestos abatement activity has occurred on certain generating units at KCP&L's Hawthorn Station resulting in a revision in timing used in computing the original present value of the asbestos ARO. Management was able to perform an analysis to update prior cost estimates determining an increase in comparison to previous estimates used in computing the original asbestos ARO. As a result of the increased costs experienced in the project at KCP&L's Hawthorn station, management performed an analysis to update prior cost estimates for KCP&L's Montrose and LaCygne Stations, determining an increase in comparison to previous estimates. As a result of these changes, KCP&L recorded a $14.2 million increase in the ARO for asbestos abatement with a corresponding increase in asset retirement costs in utility plant since December 31, 2007.

In addition, management identified an additional asbestos ARO. The wiring used in generating stations includes asbestos insulation, which would require special handling if disturbed. Due to the inability to reasonably estimate the quantities or the amount of disturbance that will be necessary during dismantlement at the end of the life of a plant, a fair value of the obligation cannot be reasonably estimated at this time. Management will continue to monitor the obligation and will recognize a liability in the period in which sufficient information becomes available to reasonably estimate its fair value.

KCP&L also has AROs related to decommissioning and site remediation of its Spearville Wind Energy Facility and for an ash pond and landfill. GMO has AROs related to asbestos in certain plants and buildings, an ash pond and landfill, removal of storage tanks and transformers containing PCBs, as well as communication towers.

The following tables summarize the change in Great Plains Energy's and KCP&L's AROs.

Great Plains Energy

December 31	2008	2007
	(millions)	
Beginning balance	$ 94.5	$ 91.8
Additions	1.4	-
Revision in timing and/or estimates	12.6	-
GMO acquisition	11.7	-
Settlements	(3.2)	(1.1)
Accretion	7.3	3.8
Ending balance	$ 124.3	$ 94.5

KCP&L

December 31	2008	2007
	(millions)	
Beginning balance	$ 94.5	$ 91.8
Additions	1.4	-
Revision in timing and/or estimates	12.6	-
Settlements	(3.2)	(1.1)
Accretion	6.6	3.8
Ending balance	$ 111.9	$ 94.5

10. 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 active and inactive employees, including officers, of KCP&L, GMO, and WCNOC and incurs significant costs in providing the plans. Pension benefits under these plans reflect the employees' compensation, years of service and age at retirement.

Effective January 1, 2008, the Company amended the defined benefit pension plan for KCP&L management employees to allow current employees the option to remain in the existing program or to choose a new retirement program which will provide, among other things, an enhanced benefit under the employee savings plan and a lower benefit accrual rate under the defined pension benefit plan. KCP&L employees hired after September 1, 2007, have been placed in the new retirement program.

KCP&L and GMO record pension expense in accordance with rate orders from the MPSC and KCC that allow 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 pension costs for ratemaking to be recognized as a regulatory asset or liability. This difference between financial and regulatory accounting methods will be eliminated over the life of the pension plans.

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, GMO, and WCNOC. The post-retirement plan reflects the Company's amended cost-sharing policy for the bargaining plan. The change increased the accumulated post-retirement benefit obligation $18.7 million. The cost of post-retirement benefits charged to KCP&L and GMO are accrued during an employee's years of service and recovered through rates.

As a result of the GMO acquisition on July 14, 2008, the Company's 2008 pension and post-retirement expenses under SFAS No. 87 and SFAS No. 106, "Employers' Accounting for Post-retirement Benefits Other Than Pensions," increased $2.4 million and $1.1 million, respectively. The under funded status of the pension and other benefit plans transferred at the date of acquisition was $48.9 million.

Current and former employees of GMO's electric and gas utility operations that were acquired by Black Hills participated in GMO's qualified pension plan, non-qualified Supplemental Executive Retirement Plan (SERP) and other post-retirement benefit plan. Under the asset purchase agreements, Black Hills assumed the accrued pension obligations owed to the former current and former employees of the operations it acquired. After the July 2008 closing, approximately $107.5 million of qualified benefit plan assets were transferred by GMO to a comparable plan established by Black Hills in accordance with terms of the asset purchase agreements, estimated to be 95% of the amount required to be transferred under applicable Employee Retirement Income Security Act of 1974, as amended (ERISA) regulations. The determination of the final amount of plan assets to be transferred is expected to be completed by plan actuaries in the first quarter of 2009. The tables below are after reflecting the Company's best estimate of the total transfer.

The Company adopted the recognition requirements of SFAS No. 158 on December 31, 2006. The Company adopted the measurement date provision of SFAS No. 158, effective December 31, 2008. The measurement date provision requires plan assets and liabilities to be measured as of the date of the employer's fiscal year-end. In prior years, the plan measurement date for the majority of the Company's plans was September 30. In lieu of remeasuring plan assets and obligations as of January 1, 2008, the Company elected to calculate the net periodic benefit cost for the fifteen-month period from September 30, 2007, to December 31, 2008, using the September 30, 2007, measurement date. The adoption of the measurement date provision resulted in KCP&L recording an adjustment of $14.1 million to a regulatory asset in accordance with regulatory treatment. In addition, $0.1 million related to non-regulated entities was recorded as an adjustment to retained earnings.

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. In 2007, contributions of $6.8 million and $7.2 million were made to the pension plan and post-retirement benefit plans, respectively, after the measurement date. For financial reporting purposes, the market value of plan assets is the fair value. KCP&L uses a five-year smoothing of assets to determine fair value for regulatory reporting purposes. 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	
	2008	2007	2008	2007
Change in projected benefit obligation (PBO)		(millions)		
PBO at beginning of year	$ 512.9	$ 508.8	$ 73.7	$ 51.5
Service cost	20.8	18.4	1.7	1.2
Interest cost	37.6	29.8	5.7	3.9
Contribution by participants	-	-	3.0	2.0
Amendments	-	(0.8)	18.7	19.5
Actuarial loss (gain)	42.9	(9.6)	1.2	(1.7)
Benefits paid	(37.1)	(35.9)	(7.0)	(3.6)
Early measurement adjustment	1.0	-	0.3	-
GMO acquisition	194.4	-	38.1	-
Special termination benefits	-	2.2	-	0.9
PBO at end of plan year	$ 772.5	$ 512.9	$ 135.4	$ 73.7
Change in plan assets				
Fair value of plan assets at beginning of year	$ 400.1	$ 364.5	$ 14.0	$ 13.4
Actual return on plan assets	(145.6)	44.1	(3.8)	(3.2)
Contributions by employer and participants	28.7	27.0	11.0	6.7
Benefits paid	(36.6)	(35.5)	(5.7)	(2.9)
Early measurement adjustment	4.0	-	7.9	-
GMO acquisition	168.1	-	15.5	-
Fair value of plan assets at end of plan year	$ 418.7	$ 400.1	$ 38.9	$ 14.0
Funded status at end of year	$ (353.8)	$ (112.8)	$ (96.5)	$ (59.7)
Amounts recognized in the consolidated balance sheets				
Current pension and other post-retirement liability	$ (3.9)	$ (0.5)	$ (0.8)	$ (0.8)
Noncurrent pension liability and other post-retirement liability	(349.9)	(112.3)	(95.7)	(58.9)
Contributions and changes after measurement date	-	6.8	-	7.2
Net amount recognized before regulatory treatment	(353.8)	(106.0)	(96.5)	(52.5)
Accumulated OCI or regulatory asset	420.2	185.4	59.1	37.8
Net amount recognized at December 31	$ 66.4	$ 79.4	$ (37.4)	$ (14.7)
Amounts in accumulated OCI or regulatory asset not yet recognized as a component of net periodic cost:				
Actuarial loss	$ 273.3	$ 86.1	$ 19.1	$ 13.8
Prior service cost	17.9	23.1	33.4	18.1
Transition obligation	0.2	0.2	4.4	5.8
Other	128.8	76.0	2.2	0.1
Net amount recognized at December 31	$ 420.2	$ 185.4	$ 59.1	$ 37.8

Great Plains Energy

Year to Date December 31	Pension Benefits 2008	2007	2006	Other Benefits 2008	2007	2006
Components of net periodic benefit costs			(millions)			
Service cost	$ 20.8	$ 18.4	$ 18.8	$ 1.7	$ 1.2	$ 0.9
Interest cost	37.6	29.8	30.9	5.7	3.9	3.0
Expected return on plan assets	(38.6)	(29.5)	(32.7)	(1.0)	(0.7)	(0.6)
Prior service cost	4.2	4.3	4.3	2.7	2.1	0.2
Recognized net actuarial loss	32.3	35.3	31.8	0.6	0.5	0.9
Transition obligation	0.1	0.1	0.1	1.2	1.2	1.2
Special termination benefits	-	1.5	-	-	0.2	-
Settlement charges	-	-	23.1	-	-	-
Net periodic benefit costs before regulatory adjustment	56.4	59.9	76.3	10.9	8.4	5.6
Regulatory adjustment	(3.5)	(9.1)	(52.3)	-	(0.1)	-
Net periodic benefit costs	52.9	50.8	24.0	10.9	8.3	5.6
Other changes in plan assets and benefit obligations recognized in OCI or regulatory assets [a]						
Current year net loss (gain)	227.1	(23.4)	-	6.0	2.7	-
Amortization of loss	(39.9)	(35.3)	-	(0.7)	(0.5)	-
Prior service cost (credit)	-	(0.9)	-	18.7	19.6	-
Amortization of prior service cost	(5.2)	(4.3)	-	(3.4)	(2.1)	-
Amortization of transition obligation	-	(0.1)	-	(1.4)	(1.2)	-
Other regulatory activity	52.8	9.1	-	2.1	0.1	-
Total recognized in OCI or regulatory asset	234.8	(54.9)	-	21.3	18.6	-
Total recognized in net periodic benefit costs and OCI or regulatory asset	$287.7	$ (4.1)	$ 24.0	$ 32.2	$ 26.9	$ 5.6

[a] Includes the effect of SFAS No. 158 remeasurement adjustment

KCP&L

Year to Date December 31	Pension Benefits 2008	2007	2006	Other Benefits 2008	2007	2006
Components of net periodic benefit costs			(millions)			
Service cost	$ 19.7	$ 18.0	$ 18.6	$ 1.7	$ 1.1	$ 0.9
Interest cost	35.6	29.2	30.5	5.6	3.8	2.9
Expected return on plan assets	(36.5)	(28.9)	(32.2)	(1.0)	(0.6)	(0.6)
Prior service cost	4.0	4.2	4.3	2.7	2.0	0.2
Recognized net actuarial loss	30.6	34.5	31.4	0.6	0.5	0.9
Transition obligation	0.1	0.1	0.1	1.2	1.2	1.1
Special termination benefits	-	1.5	-	-	0.1	-
Settlement charges	-	-	22.7	-	-	-
Net periodic benefit costs before regulatory adjustment	53.5	58.6	75.4	10.8	8.1	5.4
Regulatory adjustment	(4.5)	(9.1)	(52.3)	-	(0.1)	-
Net periodic benefit costs	49.0	49.5	23.1	10.8	8.0	5.4
Other changes in plan assets and benefit obligations recognized in OCI or regulatory assets [a]						
Current year net loss (gain)	215.0	(23.0)	-	5.8	2.7	-
Amortization of loss	(39.8)	(34.5)	-	(0.7)	(0.5)	-
Prior service cost (credit)	-	(0.8)	-	18.7	19.2	-
Amortization of prior service cost	(5.2)	(4.2)	-	(3.4)	(2.0)	-
Amortization of transition obligation	(0.1)	(0.1)	-	(1.4)	(1.2)	-
Other regulatory activity	8.6	9.1	-	2.1	0.1	-
Total recognized in OCI or regulatory asset	178.5	(53.5)	-	21.1	18.3	-
Total recognized in net periodic benefit costs and OCI or regulatory asset	$227.5	$ (4.0)	$ 23.1	$ 31.9	$ 26.3	$ 5.4

[a] Includes the effect of SFAS No. 158 remeasurement adjustment

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 2009 are $4.2 million, $36.5 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 2009 are $4.2 million, $0.2 million and $1.2 million, respectively. For financial reporting purposes, net actuarial gains and losses are recognized on a rolling five-year average basis. For regulatory reporting purposes, net actuarial gains and losses are amortized over ten years.

The accumulated benefit obligation (ABO) for all defined benefit pension plans was $675.7 million and $423.8 million at December 31, 2008 and 2007, 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.

	2008	2007
Pension plans with the ABO in excess of plan assets	(millions)	
Projected benefit obligation	$ 772.5	$ 327.5
Accumulated benefit obligation	675.7	266.4
Fair value of plan assets	418.7	220.1
Pension plans with plan assets in excess of the ABO		
Projected benefit obligation	$ -	$ 185.4
Accumulated benefit obligation	-	157.4
Fair value of plan assets	-	180.0

The GMO SERP is reflected as an unfunded ABO of $22.4 million. The Company has segregated approximately $26.2 million of assets for this plan as of December 31, 2008, and expects to fund future benefit payments from these assets.

The expected long-term rate of return on plan assets represents the Company's estimate of the long-term return on plan assets and is based on historical and projected rates of return for current and planned asset classes in the plans' investment portfolios. 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 portfolios 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**	
	2008	**2007**	**2008**	**2007**
Discount rate	6.11%	6.23%	6.10%	6.23%
Rate of compensation increase	4.27%	4.22%	4.25%	4.25%

Weighted average assumptions used to determine net costs for years ended at December 31	**Pension Benefits**		**Other Benefits**	
	2008	**2007**	**2008**	**2007**
Discount rate	6.23%	5.87%	6.23%	5.89%
Expected long-term return on plan assets	8.25%	8.25%	4.00% *	4.00% *
Rate of compensation increase	4.22%	3.81%	4.25%	3.90%

* after tax

Pension plan assets are managed in accordance with "prudent investor" guidelines contained in the ERISA requirements. The investment strategy supports the objective of the fund, which is to earn the highest possible return on plan assets within a reasonable and prudent level of risk. Investments are diversified across classes and within each class to minimize risks. At December 31, 2008 and 2007, respectively, the fair value of plan assets was $418.7 million, and $400.1 million, not including a $6.8 million subsequent contribution in 2007.

The asset allocation for the Company's pension plans at December 31, 2008 and 2007, and the target allocation for 2009 are reported in the following table. The portfolios are periodically rebalanced to generally meet target allocation percentages.

Asset Category	Target Allocation	Plan Assets at December 31 2008	2007
Equity securities	60%	59%	57%
Debt securities	33%	32%	31%
Real estate	6%	9%	6%
Other	1%	0%	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 2008 and 2009 is 8% and 7.5%, respectively, with the rate declining through 2014 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, 2008, are detailed in the following table. The results reflect the increase in the Medicare Part D employer subsidy which is assumed to increase with the medical trend and employer caps on post-65 plans.

	Increase	Decrease
	(millions)	
Effect on total service and interest component	$ 0.3	$ (0.3)
Effect on post-retirement benefit obligation	1.4	(1.5)

The Company expects to contribute $45.2 million to the plans in 2009 to meet ERISA funding requirements and regulatory orders, the majority 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 and MPSC and KCC rate orders plus additional amounts as considered appropriate; therefore, actual contributions may differ from expected contributions. The Company also expects to contribute $15.4 million to other post-retirement benefit plans in 2009, the majority of which will be paid by KCP&L. The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid through 2018.

	Pension Benefits	Other Benefits
	(millions)	
2009	$ 58.7	$ 13.0
2010	53.8	13.9
2011	54.8	14.8
2012	60.0	15.8
2013	60.5	16.6
2014-2018	331.3	97.7

Employee Savings Plans
Great Plains Energy has defined contribution savings plans (401(k)) that cover substantially all employees. Great Plains Energy matches employee contributions, subject to limits. The annual cost of the plans was approximately $6.9 million, $5.0 million and $4.8 million in 2008, 2007 and 2006, respectively. KCP&L's annual cost of the plans was approximately $5.8 million, $4.3 million and $4.1 million in 2008, 2007 and 2006, respectively.

Skill Set Realignment (Deferral) Cost
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 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. In 2007, KCP&L received authorization from the MPSC and KCC to defer $8.9 million in regulatory assets for these costs and amortize them over five years for the Missouri jurisdictional portion and ten years for the Kansas jurisdictional portion effective with new rates on January 1, 2008.

11. EQUITY COMPENSATION

Great Plains Energy's Long-Term Incentive Plan is an equity compensation plan approved by Great Plains Energy's shareholders. The Long-Term Incentive Plan permits the grant of restricted stock, stock options, limited stock appreciation rights, director shares, director deferred share units and performance shares to directors, officers and other employees of Great Plains Energy and KCP&L. The maximum number of shares of Great Plains Energy common stock that can be issued under the plan is 5.0 million. Common stock shares delivered by Great Plains Energy 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 securities laws. Great Plains Energy 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, and does not expect to repurchase common shares during 2009, to satisfy performance share payments, stock option exercises and director deferred share unit conversion.

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.

	2008	2007	2006
Great Plains Energy		(millions)	
Compensation expense	$ 9.0	$ 6.4	$ 3.9
Income tax benefits	2.7	2.1	1.2
KCP&L			
Compensation expense	5.5	4.3	2.4
Income tax benefits	2.0	1.4	0.8

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 Great Plains Energy's Board of Directors. The number of performance shares ultimately paid can vary from the number of shares initially granted depending on Great Plains Energy's performance, based on 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 related to performance shares, is recognized over the stated period.

Performance share activity for 2008 is summarized in the following table. Performance adjustment represents the number of shares of common stock related to performance shares ultimately issued that can vary from the number of performance shares initially granted depending on Great Plains Energy's performance, based on external measures, over stated performance periods.

	Performance Shares	Grant Date Fair Value*
Beginning balance	309,689	$ 30.34
Performance adjustment	(71,616)	
Granted	129,296	26.22
Issued	(49,709)	31.28
Forfeited	(3,149)	32.87
Ending balance	314,511	28.47

* weighted-average

At December 31, 2008, the remaining weighted-average contractual term was 1.1 years. The weighted-average grant-date fair value of shares granted was $26.22, $32.00 and $28.20 in 2008, 2007 and 2006, respectively. At December 31, 2008, there was $3.2 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 of common stock related to performance shares issued was $1.6 million, $1.3 million and $0.3 million during 2008, 2007 and 2006, respectively.

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 related to restricted stock, is recognized over the stated vesting period. Restricted stock activity for 2008 is summarized in the following table.

	Nonvested Restricted stock	Grant Date Fair Value*
Beginning balance	446,882	$ 31.38
Granted and issued	88,064	26.09
Vested	(71,602)	30.15
Forfeited	(4,548)	32.87
Ending balance	458,796	30.54

* weighted-average

At December 31, 2008, the remaining weighted-average contractual term was 0.9 years. The weighted-average grant-date fair value of shares granted was $26.09, $31.93 and $28.22 during 2008, 2007 and 2006, respectively. At December 31, 2008, there was $5.3 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 $2.2 million, $1.1 million and $0.8 million in 2008, 2007 and 2006, respectively.

Stock Options

Granted Under Long-Term Incentive Plan

Stock options were granted under the plan during 2001-2003 at market value of the shares on the grant date. The options vested three years after the grant date and expire in ten years if not exercised. The fair value for the stock options was estimated at the date of grant using the Black-Scholes option-pricing model. Compensation expense and accrued dividends related to stock options were recognized over the stated vesting period.

GMO Acquisition

Prior GMO stock options were converted to Great Plains Energy stock options upon acquisition.

Stock option activity under all plans for 2008 is summarized in the following table. All stock options are fully vested at December 31, 2008.

Stock Options	Shares	Exercise Price*
Beginning balance	109,472	$ 25.52
GMO acquisition	465,901	96.04
Exercised	(10,249)	20.61
Forfeited or expired	(44,295)	173.72
Outstanding and exercisable at December 31	520,829	76.10

* weighted-average

The weighted-average grant-date fair value of options exercised for 2008 was $20.61 per share. The aggregate intrinsic value and cash received for options exercised in 2008 was insignificant. The following table summarizes all outstanding and exercisable stock options as of December 31, 2008.

	Outstanding and Exercisable Options		
Exercise Price Range	Number of Shares	Weighted Average Remaining Contractual Life in Years	Weighted Average Exercise Price
$9.21 - $11.64	65,360	1.0	$ 11.54
$23.91 - $27.73	255,739	3.0	24.60
$121.90 - $181.11	161,560	0.8	149.26
$221.82 - $251.86	38,170	2.3	221.97
Total	520,829	2.0	

At December 31, 2008, the aggregate intrinsic value of in the money outstanding and exercisable options was $0.5 million.

Director Deferred Share Units

Non-employee directors receive shares of Great Plains Energy's common stock as part of their annual retainer. Each director may elect to defer receipt of their shares until the end of January in the year after they leave Great Plains Energy's Board of Directors. Prior to 2008, there were no shares of Great Plains Energy common stock issued to non-employee directors under Great Plains Energy's Long-Term Incentive Plan. At December 31, 2008, there were 7,588 shares of director deferred share units outstanding at a weighted-average grant-date fair value of $27.94 per share. The total fair value of shares of director deferred share units issued was $0.2 million for 2008.

12. SHORT-TERM BORROWINGS AND SHORT-TERM BANK LINES OF CREDIT

Great Plains Energy's $400 Million Revolving Credit Facility
Great Plains Energy's $400 million revolving credit facility with a group of banks expires in May 2011. 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, 2008, Great Plains Energy was in compliance with this covenant. At December 31, 2008, Great Plains Energy had $30.0 million of outstanding cash borrowings with a weighted-average interest rate of 1.22% and had issued letters of credit totaling $34.9 million under the credit facility. At December 31, 2007, Great Plains Energy had $42.0 million of outstanding cash borrowings with a weighted-average interest rate of 5.44% and had issued letters of credit totaling $98.6 million under the credit facility.

KCP&L's $600 Million Revolving Credit Facility
KCP&L's $600 million revolving credit facility with a group of banks to provide support for its issuance of commercial paper and other general corporate purposes expires in May 2011. 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, 2008, KCP&L was in compliance with this covenant. At December 31, 2008, KCP&L had $380.2 million of commercial paper outstanding, at a weighted-average interest rate of 5.34%, $11.9 million of letters of credit outstanding and no outstanding cash borrowings under the facility. At December 31, 2007, KCP&L had $365.8 million of commercial paper outstanding, at a weighted-average interest rate of 5.92%, $11.9 million of letters of credit outstanding and no outstanding cash borrowings under the facility.

GMO's $400 Million Revolving Credit Facility
In September 2008, GMO entered into a new $400 million revolving credit facility with a group of banks that expires in September 2011. A default by GMO 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, GMO 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, 2008, GMO was in compliance with this covenant. At December 31, 2008, GMO had $110.0 million of outstanding cash borrowings with a weighted-average interest rate of 1.22%, and had issued letters of credit totaling $1.2 million under the credit facility.

GMO's $65 Million Revolving Credit Facility
GMO's $65 million revolving credit facility expires in April 2009. Borrowings under this facility are secured by the accounts receivable generated by GMO's regulated utility operations. A default by GMO on other indebtedness totaling more than $40.0 million is a default under the facility. Under the terms of this agreement, GMO is required to maintain a consolidated indebtedness to consolidated capitalization ratio, as defined in the agreement not greater than 70% from October 1, 2008, until the termination of the agreement. GMO is required to maintain a ratio of EBITDA to interest expense for the period October 1, 2008, to the termination of the agreement, greater than 1.6 to 1.0. At December 31, 2008, GMO was in compliance with these covenants. At December 31, 2008, GMO had $64.0 million of outstanding cash borrowings with a weighted-average interest rate of 2.16%.

13. LONG-TERM DEBT

Great Plains Energy's and KCP&L's long-term debt is detailed in the following table.

	Year Due	December 31 2008	2007
		(millions)	
KCP&L			
General Mortgage Bonds			
4.90%* EIRR bonds	2012-2035	$ 158.8	$ 158.8
Senior Notes			
6.50%	2011	150.0	150.0
5.85%	2017	250.0	250.0
6.375%	2018	350.0	-
6.05%	2035	250.0	250.0
Unamortized discount		(1.8)	(1.9)
EIRR bonds			
4.65% Series 2005	2035	50.0	50.0
5.125% Series 2007A-1	2035	63.3	-
5.00% Series 2007A-2	2035	10.0	-
4.75% Series 2007A		-	73.3
5.375% Series 2007B	2035	73.2	73.2
4.90% Series 2008	2038	23.4	-
Total KCP&L		1,376.9	1,003.4
GMO			
First Mortgage Bonds			
9.44% Series	2009-2021	14.6	-
Pollution Control Bonds			
5.85% SJLP Pollution Control	2013	5.6	-
0.924% Wamego Series 1996	2026	7.3	-
2.721% State Environmental 1993	2028	5.0	-
Senior Notes			
7.625% Series	2009	68.5	-
7.95% Series	2011	137.3	-
7.75% Series	2011	197.0	-
11.875% Series	2012	500.0	-
8.27% Series	2021	80.9	-
Fair Value Adjustment		117.5	-
Medium Term Notes			
7.16% Series	2013	6.0	-
7.33% Series	2023	3.0	-
7.17% Series	2023	7.0	-
Other	2009	1.1	-
Current maturities		(70.7)	-
Total GMO		1,080.1	-
Other Great Plains Energy			
6.875% Senior Notes	2017	100.0	100.0
Unamortized discount		(0.4)	(0.5)
7.74% Affordable Housing Notes		-	0.3
Current maturities		-	(0.3)
Total Great Plains Energy excluding current maturities		$ 2,556.6	$ 1,102.9

* Weighted-average interest rates at December 31, 2008.

Amortization of Debt Expense
Great Plains Energy's and KCP&L's amortization of debt expense is detailed in the following table.

	2008	2007	2006
		(millions)	
KCP&L	$ 1.6	$ 1.6	$ 1.9
Other Great Plains Energy	1.0	1.0	0.7
Total Great Plains Energy	$ 2.6	$ 2.6	$ 2.6

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 of KCP&L's utility plant. Mortgage bonds totaling $158.8 million securing Environmental Improvement Revenue Refunding (EIRR) bonds were outstanding at December 31, 2008 and 2007.

In 2008, KCP&L remarketed the following series of EIRR bonds that were auction rate securities, i.e. the interest rates were periodically reset through an auction process:

- secured Series 1992 EIRR bonds maturing in 2017 totaling $31.0 million at a fixed rate of 5.25% through March 31, 2013,
- secured Series 1993A EIRR bonds maturing in 2023 totaling $40.0 million at a fixed rate of 5.25% through March 31, 2013, and
- secured Series 1993B EIRR bonds maturing in 2023 totaling $39.5 million at a fixed rate of 5.00% through March 31, 2011.

KCP&L Senior Notes
KCP&L had $1.0 billion and $650.0 million, respectively, of outstanding unsecured senior notes at December 31, 2008 and 2007. 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 is 5.78%. During 2007, KCP&L issued $250.0 million of 5.85% unsecured Senior Notes, maturing in 2017. As a result of amortizing the gain recognized in OCI on KCP&L's 2006 Forward Starting Swaps (FSS), the effective interest rate on KCP&L's 5.85% Senior Notes is 5.72%.

In March 2008, KCP&L issued $350.0 million of 6.375% unsecured Senior Notes, maturing in 2018. As a result of amortizing the loss recognized in OCI on KCP&L's 2007 T-Locks, the effective interest rate on KCP&L's $350.0 million of 6.375% Senior Notes is 7.49%.

KCP&L EIRR Bonds
KCP&L had $219.9 million and $196.5 million of unsecured EIRR bonds outstanding at December 31, 2008 and 2007, respectively.

In 2008, KCP&L remarketed the following auction rate EIRR bonds:

- unsecured Series 2007B EIRR bonds maturing in 2035 totaling $73.2 million at a fixed rate of 5.375% through March 31, 2013, and

- unsecured Series 2007A EIRR bonds maturing in 2035 into two series: Series 2007A-1 totaling $63.3 million at a fixed rate of 5.125% through March 31, 2011 and Series 2007A-2 totaling $10.0 million at a fixed rate of 5.00% through March 31, 2010.

After these remarketing activities and those described under KCP&L General Mortgage Bonds, none of KCP&L's EIRR bonds remain in auction rate mode.

In May 2008, KCP&L's Series 2008 EIRR bonds totaling $23.4 million maturing in 2038 were issued. Proceeds of the bonds will be used to pay for a portion of the costs at the Iatan Nos. 1 and 2 projects included in KCP&L's Comprehensive Energy Plan. The proceeds were deposited with a trustee, and will be used to reimburse KCP&L for qualifying expenditures. At December 31, 2008, KCP&L had received $13.4 million in cash proceeds and had a $10.0 million short-term receivable for the proceeds that were deposited with the trustee. The bonds have an initial long-term interest rate of 4.90% until June 30, 2013. At the end of the initial long-term interest rate period, the bonds are subject to mandatory tender; however, KCP&L is not obligated to pay the purchase price of the bonds on the mandatory tender date. If the bonds are not successfully remarketed, the bonds will bear interest at a daily rate equal to 10% per annum until all the bonds are successfully remarketed.

KCP&L Municipal Bond Insurance Policies

KCP&L's EIRR Bonds Series 2007A-1, 2007A-2 and 2007B totaling $146.5 million are covered by a municipal bond insurance policy issued by Financial Guaranty Insurance Company (FGIC). The insurance agreement between KCP&L and FGIC provides for reimbursement by KCP&L for any amounts that FGIC pays under the municipal bond insurance policy. The insurance policy is in effect for the term of the bonds. The policy also restricts the amount of secured debt KCP&L may issue. In the event KCP&L issues debt secured by liens not permitted by the agreement or resulting in the aggregate amount of outstanding general mortgage bonds exceeding 10% of total capitalization, KCP&L is required to issue and deliver collateral to FGIC, in the form of first mortgage bonds or similar securities, equal in principal amount to the principal amount of the EIRR Bonds Series 2007A-1, 2007A-2 and 2007B then outstanding.

KCP&L's secured 1992 Series EIRR bonds totaling $31.0 million, secured Series 1993A and 1993B EIRR bonds totaling $79.5 million, and secured and unsecured EIRR Bonds Series 2005 totaling $35.9 million and $50.0 million, respectively, are covered by a municipal bond insurance policy between KCP&L and Syncora Guarantee Inc. (formerly XL Capital Assurance, Inc.) (Syncora). The insurance agreements between KCP&L and Syncora provide for reimbursement by KCP&L for any amounts that Syncora 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, 2008, 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 collateral to Syncora in the form of $50.0 million of general mortgage bonds for KCP&L's obligations under the insurance agreement in the event KCP&L issues general mortgage bonds (other than refunding 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, Syncora may take any available legal or equitable action against KCP&L, including seeking specific performance of the covenants.

GMO First Mortgage Bonds
GMO has issued mortgage bonds under the General Mortgage Indenture and Deed of Trust dated April 1, 1946, as supplemented. The Indenture creates a mortgage lien on substantially all of GMO's St. Joseph Light & Power division utility plant. Mortgage bonds totaling $14.6 million were outstanding at December 31, 2008.

GMO Senior Notes
The fair value adjustment for GMO represents the $133.3 million adjustment, net of current period amortization of $15.8 million, to record GMO's debt related to the 11.875% series and 7.75% series Senior Notes, that are not reflected in electric retail rates as of the acquisition date, at estimated fair value. The increase in the fair value of the debt will be amortized as a reduction to interest expense over the remaining life of the individual debt issues. Amortization for 2009, 2010, 2011 and 2012 is estimated at $32.8 million, $34.6 million, $33.8 million and $16.3 million, respectively.

Other Great Plains Energy Long-Term Debt
During 2007, Great Plains Energy issued $100.0 million of 6.875% unsecured Senior Notes, maturing in 2017. As a result of amortizing the loss recognized in OCI on Great Plains Energy's 2007 T-Locks, the effective interest rate on Great Plains Energy's 6.875% Senior Notes is 7.33%.

Scheduled Maturities
Great Plains Energy's and KCP&L's long-term debt maturities for the next five years are detailed in the following table.

	2009	2010	2011	2012	2013
			(millions)		
KCP&L	$ -	$ -	$ 150.0	$ 12.4	$ -
Great Plains Energy	70.7	1.1	485.4	513.5	12.7

14. COMMON SHAREHOLDERS' EQUITY

Great Plains Energy has an effective shelf registration statement for the sale of unspecified amounts of securities with the Securities and Exchange Commission (SEC) that was filed and became effective in May 2006.

On August 14, 2008, Great Plains Energy entered into a Sales Agency Financing Agreement with BNY Mellon Capital Markets, LLC (BNYMCM). Under the terms of the agreement, Great Plains Energy may offer and sell up to 8,000,000 shares of its common stock from time to time through BNYMCM, as agent, for a period of no more than three years. The Company will pay BNYMCM a commission equal to 1% of the sales price of all shares sold under the agreement. As of December 31, 2008, 189,300 shares had been sold for $3.5 million in net proceeds through BNYMCM.

Treasury shares are held for future distribution upon issuance of shares in conjunction with the Company's Long-Term Incentive Plan.

Great Plains Energy has 4.0 million shares of common stock registered with the SEC for its Dividend Reinvestment and Direct Stock Purchase Plan. The plan allows for the purchase of common shares by reinvesting dividends or making optional cash payments. Great Plains Energy can issue new shares or purchase shares on the open market for the Plan. At December 31, 2008, 0.3 million shares remained available for future issuances.

Great Plains Energy has 12.3 million shares of common stock registered with the SEC for a defined contribution savings plan. Shares issued under the plans may be either newly issued shares or shares purchased in the open market. At December 31, 2008, 2.6 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 the Federal Power Act, KCP&L can only pay dividends out of retained or current earnings. 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, of total capitalization.

Great Plains Energy made capital contributions to KCP&L of $200.0 million and $94.0 million in 2008 and 2007, respectively. These contributions were made to fund Comprehensive Energy Plan projects. At December 31, 2008, KCP&L's capital contributions from Great Plains Energy totaled $828.6 million and are reflected in common stock on the KCP&L balance sheet.

15. PREFERRED STOCK

At December 31, 2008, 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 390,000 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 ranging from 101% to 103.7% of par value. If Great Plains Energy voluntarily files for dissolution or liquidation, the Cumulative Preferred Stock holders are entitled to receive the redemption prices. If a proceeding for dissolution or liquidation is filed against Great Plains Energy, the Cumulative Preferred Stock holders are entitled to receive the $100 par value per share plus accrued and unpaid dividends.

16. 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 and GMO's operations. The generation, transmission and distribution of electricity produces and requires proper management and disposal of certain hazardous products and wastes that are subject to these laws and regulations. In addition to imposing extensive and 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 KCP&L and Great Plains Energy. KCP&L and GMO seek to use current environmental technology.

It is possible that federal or relevant state or local legislation could be enacted to address global climate change. Such legislation could mandate measures to measure, control or reduce the emission of greenhouse gases, such as CO_2, which are created in the combustion of fossil fuels. In addition, there could be national and/or additional state or local mandates to produce a minimum percentage of electricity from renewable forms of energy, such as wind. While the Company believes future legislation and/or regulation addressing these matters is likely, the timing, requirements and impact of such potential legislation including the cost to obtain and install new equipment to achieve compliance, cannot be reasonably estimated at this time, but such legislation could have the potential for a significant financial and operational impact on KCP&L and GMO. KCP&L and GMO 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.

The following tables contain current estimates of Great Plains Energy's and KCP&L's capital expenditures (exclusive of AFUDC and property taxes) to comply with the current version of the Clean Air Interstate Rule (CAIR), and BART, including accelerated environmental upgrade expenditures outlined in KCP&L's Comprehensive Energy Plan. As discussed below, CAIR has been remanded to the EPA, but remains in effect until the EPA issues rules consistent with the court's order or until the court takes further action. It is not possible to project what rules the EPA may issue as a result of this remand, when the rules may be issued, or the costs associated with such rules. The actual cost of compliance with any future rules, and with BART, may be significantly different from the cost estimates provided in the following tables. The allocation between states is based on location of the facilities and has no bearing as to recovery in jurisdictional rates.

Great Plains Energy

Clean Air Estimated Environmental Expenditures [a]	**Missouri**	**Kansas**	**Total**
		(millions)	
CAIR	$417 - 443	$ -	$417 - 443
Incremental BART	245 - 424	654 - 797	899 - 1,221
Less: expenditures through December 31, 2008	(412)	-	(412)
Estimated remaining required environmental expenditures	$250 - 455	$654 - 797	$904 - 1,252

KCP&L

Clean Air Estimated Environmental Expenditures [b]	**Missouri**	**Kansas**	**Total**
		(millions)	
CAIR	$330 - 350	$ -	$330 - 350
Incremental BART	148 - 311	625 - 764	773 - 1,075
Less: expenditures through December 31, 2008	(257)	-	(257)
Estimated remaining required environmental expenditures	$221 - 404	$625 - 764	$846 - 1,168

[a] The amounts include KCP&L's and GMO's portion of the cost of projects at jointly-owned units.

[b] The amounts include KCP&L's portion of the cost of projects at jointly-owned units.

The potential capital costs of the Collaboration Agreement provisions relating to NO_x, sulfuric acid mist, SO_2 and particulate emission limits at Iatan and LaCygne generating stations are within the overall estimated capital cost ranges disclosed above. However, the tables do not reflect potential costs relating to other laws, including potential laws regarding the control of mercury emissions (discussed below), and also do not reflect costs relating to additional wind generation, energy efficiency and other CO_2 emission offsets contemplated by the Collaboration Agreement. Costs relating to the additional wind generation and energy efficiency investments that are subject to regulatory approval cannot be reasonably estimated at this time. The tables do not reflect the non-capital costs KCP&L and GMO incur on an ongoing basis to comply with environmental laws, which may in the future increase due to the implementation of the Comprehensive Energy Plan and KCP&L's and GMO's ongoing compliance with current or future environmental laws. For instance, the potential costs relating to the additional offset of approximately 711,000 tons of CO_2 emissions by the end of 2012 under the Collaboration Agreement cannot be reasonably estimated at this time. KCP&L continues to evaluate the available operational and capital resource alternatives, and will select the most cost-effective mix of actions to achieve this additional offset. KCP&L expects to seek recovery of the costs associated with the Collaboration Agreement through rate increases; however, there can be no assurance that such rate increases would be granted.

Clean Air Interstate Rule

The 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 is set to 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 are scheduled to become effective January 1, 2015. KCP&L's and GMO's fossil fuel-fired plants located in Missouri are subject to CAIR, while their fossil fuel-fired plants in Kansas are not.

On July 11, 2008, the D.C. Circuit Court of Appeals vacated CAIR in its entirety and remanded the matter to the EPA to promulgate a new rule consistent with its opinion. The EPA and others sought rehearing of the Court's decision. On December 23, 2008, the Court denied all petitions for rehearing and issued an order remanding CAIR to the EPA to revise the rule consistent with its July 2008 order. The CAIR thus remains in effect pending future EPA or court action.

EPA's future revisions to CAIR could result in a rule that requires greater emission reductions, imposes an earlier compliance deadline, changes or eliminates the NO_x fuel factor adjustment, includes additional states (including Kansas), does not allow for emissions reductions to be obtained through interstate allowance trading, or the use of the Acid Rain Program SO_2 allowances, or imposes other requirements not yet known, any of which could significantly increase compliance costs, including the capital expenditures noted in the preceding tables. Great Plains Energy and KCP&L cannot predict the outcome of the EPA's revisions to CAIR, but such revisions could have a significant effect on Great Plains Energy's results of operations, financial position and cash flows.

KCP&L and GMO expect to meet the emissions reductions required by CAIR at their Missouri plants through a combination of pollution control capital projects and the purchase of emission allowances as needed. Some of the control technology for SO_2 and NO_x could also aid in the control of mercury. CAIR currently establishes a market-based cap-and-trade program with an emission allowance allocation. Facilities demonstrate compliance with CAIR by holding sufficient allowances for each ton of SO_2 and NO_x emitted in any given year. KCP&L and GMO are currently allowed to utilize unused SO_2 emission allowances that they have either accumulated during previous years of the Acid Rain Program or purchased to meet the more stringent CAIR requirements. At December 31, 2008, KCP&L had accumulated unused SO_2 emission allowances sufficient to support over 94,000 tons of SO_2 emissions (enough to support expected requirements under the current CAIR for the foreseeable future) 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. At December 31, 2008, GMO had accumulated unused SO_2 emission allowances sufficient to support just over 32,000 tons of SO_2 emissions (enough to support expected requirements under the current CAIR through 2011), which it has received under the Acid Rain Program or purchased, which are recorded in inventory at average cost.

Analysis of the current CAIR rule indicates that NO_x and SO_2 control may be required for KCP&L's Montrose Station and GMO's Sibley and Lake Road Stations in Missouri, in addition to the environmental upgrades at Iatan No. 1 included in the Comprehensive Energy Plan. NO_x and SO_2 control for KCP&L's Montrose Station and GMO's Sibley and Lake Road Stations may be achieved under CAIR through a combination of pollution control equipment and the use or purchase of emission allowances as needed. As required by the Collaboration Agreement, an interim status report was completed in 2008 to update progress on underlying studies. An assessment of the potential future use of Montrose Station, including without limitation, retiring, re-powering and upgrading the units will be completed in 2009.

Best Available Retrofit Technology Rule

The EPA BART rule 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 KCP&L's LaCygne Nos. 1 and 2 in Kansas, KCP&L's Iatan No. 1, in which GMO has an interest, and KCP&L's Montrose No. 3 in Missouri, GMO's Sibley Unit No. 3 and Lake Road Unit No. 6 in Missouri and Westar's Jeffrey Unit Nos. 1 and 2 in Kansas, in which GMO has an 8% interest. Initially, in Missouri, compliance with CAIR will be compliance with BART for individual sources. Depending on how and when the EPA revises CAIR in response to the court's order, the timing of installation of environmental control equipment and the availability of SO_2 emission allowances, the estimated required environmental expenditures presented in the table above could shift from CAIR to incremental BART for Missouri. Neither Missouri nor Kansas has received EPA approval for their BART plans. In the Collaboration Agreement, KCP&L agreed to seek a consent agreement, which it has done, with the Kansas Department of Health and Environment (KDHE) incorporating limits for stack particulate matter emissions, as

well as limits for NO_x and SO_2 emissions at its LaCygne Station that will be below the presumptive limits under BART. KCP&L further agreed to use its best efforts to install emission control technologies to reduce those emissions from the LaCygne Station prior to the required compliance date under BART, but in no event later than June 1, 2015. KCP&L further agreed to issue requests for proposal for equipment required to comply with BART by December 31, 2008, requesting that construction commence by December 31, 2010, and has done so.

New Source Review

The Clean Air Act requires companies to obtain permits and, if necessary, install control equipment to reduce emissions when making a major modification or a change in operation if either is expected to cause a significant net increase in regulated emissions. In May 2008, KCP&L received a subpoena from a federal grand jury seeking documents relating to capital projects at Iatan No. 1. KCP&L expects to complete the delivery of responsive documents by early March 2009. KCP&L believes that it is in compliance in all material respects with all relevant laws and regulations; however, the ultimate outcome of these grand jury activities or possible civil or administrative proceedings regarding capital projects at Iatan No. 1 and other coal units cannot presently be determined, nor can the liability that could potentially result from a negative outcome presently be reasonably estimated. There is no assurance these costs, if any, could be recovered in rates.

In January 2004, Westar Energy, Inc. (Westar) received notification from the EPA alleging that it had violated new source review requirements and Kansas environmental regulations by making modifications to the Jeffrey Energy Center without obtaining the proper permits. The Jeffrey Energy Center is a coal-fired plant located in Kansas that is 92% owned by Westar and operated exclusively by Westar. GMO has an 8% interest in the Jeffrey Energy Center and is generally responsible for its 8% share of the facility's operating costs and capital expenditures. On February 4, 2009, the Attorney General of the United States filed a complaint against Westar alleging that it violated the Clean Air Act and related federal and state regulations by making major modifications to the Jeffrey Energy Center beginning in 1994 without first obtaining appropriate permits authorizing this construction and without installing and operating best available control technology to control emissions. At this time (although no settlement has been reached), it is possible that Westar could be required to make significant capital and other expenditures to install and operate new emission control systems at the Jeffrey Energy Center, surrender emission allowances, interrupt or shut-down operations at the Jeffrey Energy Center, apply for new or modified permits, audit Jeffrey Energy Center operations, otherwise mitigate any harm to public health and the environment resulting from the alleged violations, and pay a civil penalty of up to $37,500 per day for each violation.

The ultimate outcome of any of the above matters cannot presently be determined, nor can the costs and other liabilities that could potentially result from a negative outcome presently be reasonably estimated. There is no assurance these costs, if any, could be recovered in rates and failure to recover such costs could have a significant adverse effect on Great Plains Energy's or KCP&L's results of operations, financial position and cash flows.

Mercury Emissions

The EPA Clean Air Mercury Rule (CAMR) regulated mercury emissions from coal-fired power plants located in 48 states, including Kansas and Missouri, under the Clean Air Act. In February 2008, a court vacated and remanded CAMR back to the EPA and the rule is effectively void. In May 2008, petitions for rehearing of the matter by the full court were denied. Petitions for review by the Supreme Court were filed by the EPA and an industry group. In February 2009, the Supreme Court denied the industry group's petition for review and the EPA withdrew is petition for review. It is likely that the EPA will develop maximum achievable control technology (MACT) standards for mercury emissions. These MACT standards, if adopted, could impact both KCP&L's and GMO's new and existing facilities. In January 2009, the EPA issued a memorandum stating that new electric steam generating units (EGUs) that began construction while the CAMR was effective are subject to a new source MACT determination on a case-by-case basis. This is an outcome of the D.C. Court of Appeals' vacatur of both the CAMR and contemporaneously promulgated rule removing EGUs from MACT requirements. Iatan No. 2 is an affected EGU. It is currently not known how this memorandum will impact the permitting requirements for Iatan Station, but it is possible a MACT determination may be required and may ultimately

impose additional emission control equipment and permit limits. The estimated required environmental expenditures presented in the tables above do not reflect any amounts for compliance with the vacated CAMR or possible MACT standards because management cannot predict the outcome of further judicial, administrative or regulatory actions or their financial or operational effects on Great Plains Energy and KCP&L. However, such actions could have a significant effect on Great Plains Energy's and KCP&L's results of operations, financial position and cash flows.

Greenhouse Gases

Many bills concerning the reduction of emissions of greenhouse gases, including CO_2, are being debated at the federal and state levels, and some initial steps toward definitive regulation have been taken, all with various compliance dates and reduction strategies. At the federal level, it is anticipated that due to the outcome of the 2008 election, additional greenhouse gas bills will be introduced in Congress and legislation ultimately enacted, but when and to what extent such legislation will regulate CO_2 cannot be determined at this time. Even if there are no new Congressional mandates, the EPA is considering several issues which may lead to increased regulation of greenhouse gases under the existing Clean Air Act. First, the U.S. Supreme Court has determined that the EPA has statutory authority to regulate CO_2 from new motor vehicles if the EPA forms a judgment that such emissions contribute to climate change. If the EPA forms such a judgment, as currently anticipated, it may ultimately regulate other sources of CO_2, which may include KCP&L and GMO facilities. In July 2008, the EPA issued an advance notice of proposed rulemaking seeking public comment on the ramifications of regulating greenhouse gas emissions under the Clean Air Act. In December 2008, the EPA issued an interpretive memo declaring that CO_2 is not currently subject to regulation under the Federal Prevention of Significant Deterioration (PSD) permit program; although, this will not prevent PSD regulation of CO_2 if the EPA promulgates regulations establishing Clear Air Act emission limitations or standards for CO_2. In addition, the EPA announced in February 2009 that it plans to reconsider the interpretive memo and publish a related notice of rulemaking in the near future. The EPA's reconsideration of the memo may result in a differing interpretation of the Clean Air Act and PSD requirements. At the state level, the governor of Kansas supports mandatory renewable energy portfolio standards, and bills that would establish such standards have been introduced in the 2009 Kansas Legislature. The KDHE has indicated that it intends to engage industries and stakeholders to establish goals for reducing CO_2 emissions and strategies to achieve those goals. In the November 2008 Missouri general election, voters passed an initiative requiring at least 2% of the electricity generated by Missouri investor-owned utilities (including KCP&L and GMO) to come from renewable resources, such as wind, solar, biomass and hydropower by 2011 and that 15% come from such sources by 2021. Additionally, in November 2007, governors from six Midwestern states, including Kansas and Missouri, signed the Midwestern Greenhouse Gas Reduction Accord, which has established the goal of reducing member states' greenhouse gas emissions to 15% to 20% below 2005 levels by 2020, and 60% to 80% below 2005 levels by 2050. Approximately 2% of KCP&L's 2009 generation is expected to come from wind generation.

Greenhouse gas regulation has the potential for a significant financial and operational impact on KCP&L and GMO in connection with achieving compliance with limits that may be established. However, the financial and operational consequences to Great Plains Energy and KCP&L cannot be determined until final legislation is passed or regulations enacted. Management will continue to monitor the progress of relevant bills and regulations. As previously discussed, KCP&L has entered into a Collaboration Agreement that includes various provisions regarding wind generation, energy efficiency and other CO_2 offsets.

Ozone

In June 2007, monitor data indicated that the Kansas City area violated the primary eight-hour ozone national ambient air quality standard (NAAQS). Missouri and Kansas have implemented the responses established in the maintenance plans for control of ozone. The responses in both states do not require additional controls at KCP&L's and GMO's generation facilities beyond the currently proposed controls for CAIR and BART. The EPA has various options over and above the implementation of the maintenance plans for control of ozone to address a confirmed violation. These options include, but are not limited to, designating the area "non-attainment" and requiring a new regulatory plan to reduce emissions or leaving the designation unchanged, but

still requiring a new regulatory plan. At this time, management is unable to predict how the EPA will respond or how that response will impact KCP&L's and GMO's operations. However, the EPA's response could have a significant effect on Great Plains Energy's and KCP&L's results of operations, financial position and cash flows.

On March 12, 2008, the EPA significantly strengthened its NAAQS for ground-level ozone. The EPA is revising the primary eight-hour ozone standard, designed to protect public health, to a level of 0.075 parts per million (ppm). The EPA is also strengthening the secondary eight-hour ozone standard to the level of 0.075 ppm making it identical to the revised primary standard. The previous primary and secondary standards, set in 1997, were effectively 0.084 ppm.

By March 2009, states are required to make recommendations for areas to be designated attainment and nonattainment. The Missouri Department of Natural Resources (MDNR) and KDHE have issued draft determinations that the Kansas City area is a nonattainment area. By March 2010, the EPA will make final designations of attainment and nonattainment areas. By 2013, states must submit state implementation plans outlining how states will reduce ozone to meet the standards in nonattainment areas. Although the impact on KCP&L's and GMO's operations will not be known until after the final nonattainment designations and the state implementation plans are submitted, it could have a significant effect on Great Plains Energy's and KCP&L's results of operations, financial position and cash flows.

Sulfuric Acid Mist BACT Analysis – Iatan Station
As a requirement of the Iatan Station air permit and the Collaboration Agreement, KCP&L submitted a best available control technology (BACT) analysis for sulfuric acid mist to MDNR in June 2007. MDNR conducted its own BACT analysis and determined the final emission limit in October 2008. Management believes the final emission limit is achievable based on emission guarantees associated with the currently proposed emission control equipment for Iatan Nos. 1 and 2.

Water Use Regulations
The Clean Water Act (Act) establishes standards for cooling water intake structures. The EPA had previously issued regulations pursuant to Section 316(b) of the Act regarding cooling water intake structures. Subsequent to an appellate court ruling, the EPA suspended the regulations and is engaged in further rulemaking on this matter. In April 2008, the Supreme Court agreed to hear an appeal on the issue of whether the Act authorized the EPA to compare costs with benefits in determining the best technology available for minimizing adverse environmental impact at cooling water intake structures. At this time, management is unable to predict the outcome of this proceeding, how the EPA will respond or how that response will impact KCP&L's and GMO's operations.

KCP&L holds a permit from the MDNR 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 have a significant impact on KCP&L. The outcome could also affect the terms of water permit renewals at KCP&L's Iatan and Montrose Stations and at GMO's Sibley and Lake Road Stations.

Environmental Remediation
Some federal and state laws hold current and previous owners or operators of real property, and any person who arranges for the disposal or treatment of hazardous substances at a property, liable for the costs of cleaning up contamination at or migrating from such real property, even if they did not know of and were not responsible for such contamination. Certain such laws also authorize the EPA and other agencies to issue orders compelling potentially responsible parties to clean up sites that are determined to present an actual or potential threat to human health or the environment. GMO is named as a potentially responsible party at two disposal sites for polychlorinated biphenyls (PCBs), and retains some environmental liability for several operations and investments it no longer owns. In addition, GMO also owns, or has acquired liabilities from companies that once owned or operated former manufactured gas plant (MGP) sites, which are subject to the supervision of the EPA and various state environmental agencies.

At December 31, 2008 and 2007, KCP&L had $0.3 million accrued for environmental remediation expenses. The accrual covers ground water monitoring at a former MGP site. At December 31, 2008, Great Plains Energy had $0.5 million accrued for environmental remediation expenses, which includes the $0.3 million at KCP&L, and additional potential remediation and ground water monitoring costs relating to two GMO sites. The amounts accrued were established on an undiscounted basis and Great Plains Energy and KCP&L do not currently have an estimated time frame over which the accrued amounts may be paid.

In addition to the $0.5 million accrual above, at December 31, 2008, Great Plains Energy had $2.0 million accrued for the future investigation and remediation of certain additional GMO identified MGP sites, PCB sites and retained liabilities. This estimate was based upon review of the potential costs associated with conducting investigative and remedial actions at identified sites, as well as the likelihood of whether such actions will be necessary. There are also additional costs that are considered to be less likely but still "reasonably possible" to be incurred at these sites. Based upon the results of studies at these sites and knowledge and review of potential remedial actions, it is reasonably possible that these additional costs could exceed the estimate by approximately $1.3 million. This estimate could change materially after further investigation, and could also be affected by the actions of environmental agencies and the financial viability of other potentially responsible parties.

GMO has pursued recovery from insurance carriers and other potentially responsible parties. As a result of a settlement with an insurance carrier, approximately $2.1 million in insurance proceeds less an annual deductible is available to GMO to recover qualified MGP remediation expenses. GMO would seek recovery of additional remediation costs and expenses through rate increases; however, there can be no assurance that such rate increases would be granted.

Contractual Commitments
Great Plains Energy's and KCP&L's expenses related to lease commitments are detailed in the following table.

	2008	2007	2006
		(millions)	
KCP&L	$ 18.1	$ 17.3	$ 17.6
Great Plains Energy [(a)]	20.7	18.6	18.9

[(a)] Includes insignificant amounts related to discontinued operations.

Great Plains Energy's and KCP&L's contractual commitments at December 31, 2008, excluding pensions and long-term debt, are detailed in the following tables.

Great Plains Energy

	2009	2010	2011	2012	2013	After 2013	Total
Lease commitments				(millions)			
Operating lease	$ 18.3	$ 16.7	$ 15.9	$ 15.6	$ 14.2	$ 167.3	$ 248.0
Capital lease	0.2	0.3	0.3	0.3	0.3	5.4	6.8
Purchase commitments							
Fuel	186.2	170.8	90.6	74.6	84.9	147.7	754.8
Purchased capacity	33.5	29.6	19.9	14.1	13.1	11.7	121.9
Comprehensive Energy Plan	376.2	74.3	-	-	-	-	450.5
Non-regulated natural gas transportation	5.5	5.5	5.0	2.6	2.6	8.2	29.4
Other	70.3	27.4	13.4	7.5	7.3	37.1	163.0
Total contractual commitments	$ 690.2	$ 324.6	$ 145.1	$ 114.7	$ 122.4	$ 377.4	$ 1,774.4

KCP&L

	2009	2010	2011	2012	2013	After 2013	Total
Lease commitments				(millions)			
Operating lease	$ 14.0	$ 13.1	$ 12.3	$ 12.0	$ 12.0	$ 155.8	$ 219.2
Capital lease	0.2	0.2	0.2	0.2	0.2	3.4	4.4
Purchase commitments							
Fuel	126.7	127.8	72.0	57.4	67.7	147.7	599.3
Purchased capacity	8.6	6.3	4.7	4.7	3.7	7.2	35.2
Comprehensive Energy Plan	376.2	74.3	-	-	-	-	450.5
Other	64.1	24.4	10.4	4.5	4.3	21.8	129.5
Total contractual commitments	$ 589.8	$ 246.1	$ 99.6	$ 78.8	$ 87.9	$ 335.9	$ 1,438.1

Great Plains Energy has sublease income of $4.9 million for the years 2009-2013 and $0.5 million in total thereafter. Lease commitments end in 2032. Operating lease commitments include rail cars 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 ($18.2 million total) of the amounts included in the table above.

Fuel commitments consist of commitments for nuclear fuel, coal, coal transportation and natural gas. KCP&L and GMO purchase 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 2009 through 2011, $6.9 million in 2012 and $1.6 million in 2013. Comprehensive Energy Plan represents contractual commitments for projects included in KCP&L's Comprehensive Energy Plan including jointly owned units. KCP&L expects to be reimbursed by other owners, including GMO, for their respective share of Iatan No. 2 and environmental retrofit costs included in the Comprehensive Energy Plan contractual commitments. Non-regulated natural gas transportation consists of MPS Merchant's commitments. Other represents individual commitments entered into in the ordinary course of business.

17. LEGAL PROCEEDINGS

Kansas City Power & Light Company v. Union Pacific Railroad Company

In October 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 Powder River Basin (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.

On May 16, 2008, the STB found that the rates Union Pacific charged on coal movement from the PRB to KCP&L's Montrose Station exceeded the maximum reasonable rate of 180% of variable costs. Consequently, the STB prescribed a maximum reasonable rate of 180% of variable costs until the end of 2015. Additionally, the STB ordered reparations to be paid, with interest, for coal deliveries made from January 1, 2006 through the date a new rate is established. In the third quarter of 2008, KCP&L received approximately $3 million for reparations and interest for 2006 coal deliveries, which was recorded as a regulatory liability to be refunded to retail customers. Reparations for subsequent periods cannot be calculated at this time because actual costs for the period have not been finalized. Union Pacific did not appeal the decision.

KCP&L Hawthorn No. 5 Litigation

KCP&L received reimbursement for the 1999 Hawthorn No. 5 boiler explosion 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 Fire Insurance Company of Pittsburgh, Pennsylvania, (National Union) and KCP&L was added as a defendant in June 2006. The case was subsequently transferred to the U.S. District Court for the Western District of Missouri. Travelers sought recovery of $10 million that KCP&L recovered through subrogation litigation. On July 24, 2008, the Court held that Travelers is not entitled to any recovery from KCP&L. Travelers has the right to appeal this decision, although no appeal has been filed at this time.

KCP&L 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 nuclear fuel for disposal in January 1998, as the government was required to do by the Nuclear Waste Policy Act of 1982. Approximately sixty-five other similar cases were filed with that court, a few of which have settled. To date, the court has rendered final decisions in several of the cases, 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 appellate court has already 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.

Weinstein v. KLT Telecom

Richard D. Weinstein (Weinstein) filed suit against KLT Telecom Inc. (KLT Telecom) in September 2003 in the Circuit Court of St. Louis County, Missouri. 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 March 2008, the parties settled this matter for an amount less than the $15 million reserve recorded in 2001 and Great Plains Energy released the remaining reserve resulting in $3.4 million of after-tax income.

GMO Price Reporting Litigation

In response to complaints of manipulation of the California energy market, in 2002 FERC issued an order requiring net sellers of power in the California markets from October 2, 2000, through June 20, 2001, at prices above a FERC determined competitive market clearing price to make refunds to net purchasers of power in the California market during that time period. Because MPS Merchant was a net purchaser of power during the refund period it has received approximately $8.1 million in refunds. MPS Merchant estimates that it is entitled to an additional $14 million in refunds under the standards FERC has used in this case. However, various parties appealed the FERC order to the United States Court of Appeals for the Ninth Circuit seeking review of a number of issues, including changing the refund period to include periods prior to October 2, 2000. MPS Merchant was a net seller of power during the period prior to October 2, 2000. If FERC ultimately includes that period, MPS Merchant could be found to owe refunds. On August 2, 2006, the U.S. Court of Appeals for the Ninth Circuit issued an order finding, among other things, that FERC did not provide a sufficient justification for refusing to exercise its remedial authority under the Federal Power Act to determine whether market participants violated FERC-approved tariffs during the period prior to October 2, 2000, and imposing a remedy for any such violations. The court remanded the matter to FERC to determine whether tariff violations occurred and, if so, the appropriate remedy. In March 2008, FERC issued an order declining to order refunds for the period prior to October 2, 2000. That order has been appealed to the U.S. Court of Appeals for the Ninth Circuit. In addition, FERC initiated a docket, generally referred to as the Pacific Northwest refund proceeding, to determine if any refunds were warranted related to the potential impact of the California market issues on buyers in the Pacific Northwest between December 25, 2000, and June 20, 2001. The City of Seattle has claimed that MPS Merchant owes the city a $4.1 million refund. The ultimate outcome of these matters cannot be predicted.

On October 6, 2006, the MPSC filed suit in the Circuit Court of Jackson County, Missouri against 18 companies, including GMO and MPS Merchant alleging that the companies manipulated natural gas prices through the misreporting of natural gas trade data and, therefore, violated Missouri antitrust laws. The suit does not specify alleged damages and was filed on behalf of all local distribution gas companies in Missouri who bought and sold natural gas from June 2000 to October 2002. The defendants' motions to dismiss the case were granted in January 2009. The MPSC has appealed the dismissal to the Missouri Court of Appeals for the Western District of Missouri.

GMO South Harper Peaking Facility

GMO constructed a 315 MW natural gas power plant and related substation in an unincorporated area of Cass County, Missouri. Cass County and local residents filed suit claiming that county approval was required to construct the project. In April 2008, GMO entered into an agreement with Cass County pursuant to which it filed and Cass County approved a land use application for the South Harper facilities. GMO entered into a final settlement agreement with the members of StopAquila.org, an unincorporated association of approximately 100 individuals who opposed the facilities, and has settled all seven of the original private lawsuits filed by Cass County residents alleging that the facilities constitute a public and private nuisance. In August 2008, a law took effect that grants the MPSC the authority to retroactively approve the development and construction of the South Harper facilities. GMO has filed an application with the MPSC and reached a stipulation and agreement with the parties. The stipulation and agreement is pending MPSC decision.

GMO Coal Supply Litigation

In the spring of 2005, one of GMO's coal suppliers, C.W. Mining, terminated a long-term, fixed price coal supply agreement allegedly because of a force majeure event. GMO incurred significant costs procuring replacement coal and disputed that the supplier was entitled to terminate the contract. GMO filed a lawsuit against the supplier in federal court in Salt Lake City and the trial was held in February 2007. On October 29, 2007, the United States District Court for the District of Utah, Central Division held that C.W. Mining's performance under the coal

contract was not excused by a force majeure event and awarded GMO $24.8 million in damages. In order to preserve and recover on its claim, on January 8, 2008, GMO participated in the filing of an involuntary Chapter 11 bankruptcy petition against C.W. Mining in the United States Bankruptcy Court in Salt Lake City, Utah. In September 2008, the Bankruptcy Court granted GMO's motions for partial summary judgment, effectively putting C.W. Mining into bankruptcy. In July 2008, parties affiliated with C.W. Mining filed suit against GMO, alleging that GMO's efforts to collect on its judgment constituted conversion, abuse of process, intentional interference with economic relations and civil conspiracy, asserting $217 million in damages and requesting punitive damages. In October 2008, the plaintiffs dismissed this suit without prejudice. The underlying judgment was affirmed by the 10th Circuit Court of Appeals on November 7, 2008. On November 11, 2008, GMO's Motion to Appoint a Trustee was granted.

Everest Minority Shareholder Litigation

Minority shareholders of a former subsidiary of GMO brought suit against GMO in Circuit Court in St. Charles County, Missouri, asserting that they are entitled to put their shares to GMO for approximately $5 million because the subsidiary failed to obtain 30,000 customers by the end of 2004. Under the put agreement, if there was a dispute regarding the customer count, it was to be resolved by an audit firm. GMO has paid $2.3 million to the minority shareholders under related market-based put provisions. The audit firm issued a report stating that the customer count was met. Discovery in this case is continuing.

18. GUARANTEES

In the ordinary 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. 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. At December 31, 2008, Great Plains Energy has provided $1,144.6 million of credit support for certain subsidiaries as follows:

- Great Plains Energy letters of credit totaling $4.0 million to KCP&L counterparties, which expire in 2009,
- Great Plains Energy direct guarantees to GMO counterparties totaling $88.9 million, which expire in 2009,
- Great Plains Energy letters of credit totaling $30.9 million to GMO counterparties, which expire in 2009, and
- Great Plains Energy guarantee of GMO long-term debt totaling $1,020.8 million, which includes debt with maturity dates ranging from 2009-2023.

At December 31, 2008, KCP&L had guaranteed, with a maximum potential of $1.9 million, energy savings under an agreement with a customer that expires over the next two 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."

19. RELATED PARTY TRANSACTIONS AND RELATIONSHIPS

KCP&L and GMO receive various support and administrative services from Services. These services are billed at cost, based on payroll and other expenses, incurred by Services for the benefit of KCP&L and GMO. These costs totaled $13.0 million, $14.9 million and $18.5 million for 2008, 2007 and 2006, respectively, for KCP&L and $2.4 million in 2008 for GMO. These costs consisted primarily of employee compensation, benefits and fees associated with various professional services. In December 2008, employees and assets of Services were transferred to KCP&L. KCP&L employees manage GMO's business and operate its facilities at cost. These costs totaled $41.0 million since the July 14, 2008, acquisition of GMO. Additionally, KCP&L and GMO engage in wholesale electricity transactions with each other. At December 31, 2007, KCP&L's balance sheet reflects a note payable from HSS to Great Plains Energy of $0.6 million. The following table summarizes KCP&L's related party receivables and payables.

	December 31	
	2008	2007
	(millions)	
Receivable from GMO	$ 23.7	$ -
Receivable (payable) from/to Great Plains Energy	(1.2)	10.5
Payable to MPS Merchant	(3.4)	-
Receivable (payable) from/to Services	4.8	(1.8)
Deferred credits - other - payable to Services	-	(1.5)

20. 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 an internal risk management committee. 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 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. 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 of derivative instruments are recognized currently in net income unless specific hedge accounting criteria are met, except GMO utility operations hedges that are recorded to a regulatory asset or liability consistent with MPSC regulatory orders, as discussed below.

Interest Rate Risk Management

Forward Starting Swaps

In July 2007, Great Plains Energy entered into three FSS, with a total notional amount of $250.0 million, to hedge against interest rate fluctuations on future issuances of long-term debt. The FSS were designed to effectively remove most of the interest rate uncertainty and, to the extent that swap spreads correlate with credit spreads, some degree of credit spread uncertainty with respect to the debt to be issued, thereby enabling Great Plains Energy to predict with greater assurance its future interest costs on that debt. The FSS were originally for anticipated financing related to the GMO acquisition and treated as an economic hedge. Due to a change in financing plans, during the second quarter of 2008, Great Plains Energy redesignated the FSS from an economic hedge (non-hedging derivative) to a cash flow hedge. Prior to the redesignation, the change in the fair value of the FSS increased interest expense by $9.2 million year to date June 30, 2008. Subsequent to the redesignation,

the FSS are accounted for as cash flow hedges and the fair value is recorded as a current asset or liability with an offsetting entry to OCI, to the extent the hedges are effective, until the forecasted transaction occurs. No ineffectiveness has been recorded on the FSS since June 30, 2008. Due to another change in financing plans, Great Plains Energy assigned the FSS to KCP&L. 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.

Treasury Locks

In 2007, Great Plains Energy entered into three T-Locks, with a notional amount of $350.0 million, to hedge against interest rate fluctuations on the U.S. Treasury rate component on future issuances of long-term debt. Following a change in financing plans, Great Plains Energy assigned the T-Locks to KCP&L. In the first quarter of 2008, KCP&L issued $350.0 million 10-year long-term debt and the T-Locks settled simultaneously with the issuance of this long-term fixed rate debt. The T-Locks were accounted for as cash flow hedges and KCP&L's interest expense for 2008 includes a loss of $0.7 million due to ineffectiveness of the cash flow hedge. A pre-tax loss of $39.1 million was recorded to OCI and is being reclassified to interest expense over the life of the 10-year debt. In 2008, $3.3 million of the loss has been reclassified from OCI to interest expense. At December 31, 2008, KCP&L had $35.8 million recorded in accumulated OCI for the T-Locks.

In 2006, Great Plains Energy entered into a T-Lock to hedge against interest rate fluctuations on an anticipated $100.0 million 10-year long-term debt issuance. In the first quarter of 2007, Great Plains Energy allowed the T-Lock to expire while the terms of the debt offering were re-evaluated and the resulting $0.1 million loss was recorded to interest expense as cash flow ineffectiveness.

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. At December 31, 2008, KCP&L has hedged 31% and 3%, respectively, of its 2009 and 2010 projected natural gas usage for retail load and firm MWh sales, primarily by utilizing futures contracts and financial instruments. 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 uses derivative instruments to mitigate its exposure to market price fluctuations on a portion of the projected fuel oil purchases to meet the startup requirements for Iatan No. 2. At December 31, 2008, KCP&L has hedged 15% of the projected fuel oil purchases for the startup of Iatan No. 2 utilizing futures 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.

GMO's price risk policy is to use derivative instruments to mitigate price exposure to natural gas price volatility in the market. This program extends multiple years and the mark-to-market value of the portfolio relates to financial contracts that will settle against actual purchases of natural gas and purchased power in 2008 through 2010. At December 31, 2008, GMO had financial contracts in place to hedge approximately 65% and 4% of the expected on-peak natural gas and natural gas equivalent purchased power price exposure for 2009 and 2010, respectively. In connection with GMO's 2005 Missouri electric rate case, it was agreed that these contracts would be recognized into the cost of sales when they settle. The settlement cost is a component of the energy cost included in GMO's Missouri fuel adjustment clause. A regulatory asset has been recorded to reflect the change in the timing of recognition authorized by the MPSC. To the extent that recovery of actual costs incurred is allowed, amounts will not impact earnings, but will impact cash flows due to the timing of the recovery mechanism.

MPS Merchant manages the daily delivery of its remaining contractual commitments to reduce its exposure to changes in market prices. Within the trading portfolio, MPS Merchant takes certain positions to hedge physical sale or purchase contracts. MPS Merchant records trading energy contracts, both physical and financial, at fair

value in accordance with SFAS No. 133. Changes in fair value are recorded in the consolidated statements of income in non-operating income and on the consolidated balance sheets in derivative assets or liabilities.

The notional and recorded fair values of the companies' open positions for derivative instruments are summarized in the following table. The fair values of these derivatives are recorded on the consolidated balance sheets.

	December 31			
	2008		2007	
	Notional Contract Amount	Fair Value	Notional Contract Amount	Fair Value
	(millions)			
Great Plains Energy				
Swap contracts				
Cash flow hedges	$ 0.7	$ (0.2)	$ 5.5	$ 0.7
Non-hedging derivatives	46.2	(7.4)	-	-
Forward contracts				
Cash flow hedges	4.5	0.6	1.4	-
Non-hedging derivatives	317.3	7.8	-	-
Option contracts				
Non-hedging derivatives	28.2	0.2	-	-
Anticipated debt issuance				
Forward starting swap	250.0	(80.1)	-	-
Treasury lock	-	-	350.0	(28.0)
Non-hedging derivatives	-	-	250.0	(16.4)
KCP&L				
Swap contracts				
Cash flow hedges	0.7	(0.2)	5.5	0.7
Forward contracts				
Cash flow hedges	4.5	0.6	1.4	-
Anticipated debt issuance				
Forward starting swap	250.0	(80.1)	-	-
Treasury lock	-	-	350.0	(28.0)

The amounts recorded in accumulated OCI related to the cash flow hedges are summarized in the following table.

	Great Plains Energy December 31		KCP&L December 31	
	2008	2007	2008	2007
	(millions)			
Current assets	$ 13.7	$ 14.6	$ 13.7	$ 14.6
Current liabilities	(94.6)	(31.0)	(90.5)	(26.6)
Deferred income taxes	31.5	6.2	29.9	4.5
Assets of discontinued operations	-	31.0	-	-
Liabilities of discontinued operations	-	(16.9)	-	-
Deferred income taxes, included in assets and liabilities of discontinued operations	-	(5.8)	-	-
Total	$ (49.4)	$ (1.9)	$ (46.9)	$ (7.5)

Great Plains Energy's accumulated OCI in the table above at December 31, 2008, includes $3.9 million that is expected to be reclassified to expenses over the next twelve months. KCP&L's accumulated OCI includes $3.2 million that is expected to be reclassified to expense over the next twelve months.

The amounts reclassified to expenses are summarized in the following table.

	2008	2007	2006
Great Plains Energy		(millions)	
Fuel expense	$ (2.3)	$ -	$ -
Interest expense	2.8	(0.4)	(0.4)
Income taxes	(0.2)	0.1	0.2
Income (loss) from discontinued operations			
Purchased power expense	(106.1)	83.7	54.6
Income taxes	43.8	(34.2)	(22.6)
OCI	$ (62.0)	$ 49.2	$ 31.8
KCP&L			
Fuel expense	$ (2.3)	$ -	$ -
Interest expense	2.5	(0.6)	(0.4)
Income taxes	-	0.2	0.2
OCI	$ 0.2	$ (0.4)	$ (0.2)

21. FAIR VALUE MEASUREMENTS

Great Plains Energy and KCP&L adopted SFAS No. 157, "Fair Value Measurements" effective January 1, 2008. This statement defines fair value, establishes a framework for measuring fair value in 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.

SFAS No. 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. SFAS No. 157 establishes a fair value hierarchy, which prioritizes the inputs to valuation techniques used to measure fair value into three broad categories, giving the highest priority to quoted prices in active markets for identical assets or liabilities and lowest priority to unobservable inputs. A definition of the various levels, as well as discussion of the various Company measurements within the levels is as follows:

Level 1 – Unadjusted quoted prices for identical assets or liabilities in active markets that the Company has access to at the measurement date. Assets categorized within this level consist of Great Plains Energy's various exchange traded derivative instruments and equity and certain U.S. Treasury securities that are actively traded within KCP&L's decommissioning trust fund and GMO's SERP rabbi trust fund.

Level 2 – Market-based inputs for assets or liabilities that are observable (either directly or indirectly) or inputs that are not observable but are corroborated by market data. Assets and liabilities categorized within this level consist of KCP&L's and Great Plains Energy's various non-exchange traded derivative instruments traded in over-the-counter markets and debt securities and certain U.S. Agency securities within KCP&L's decommissioning trust fund GMO's SERP rabbi trust fund.

Level 3 – Unobservable inputs, reflecting the Company's own assumptions about the assumptions market participants would use in pricing the asset or liability. Assets categorized within this level consist of Great Plains Energy's various non-exchange traded derivative instruments traded in over-the-counter markets and mortgage-backed securities within KCP&L's decommissioning trust fund for which sufficiently observable market data is not available to corroborate the valuation inputs.

The following table includes Great Plains Energy's and KCP&L's balances of financial assets and liabilities measured at fair value on a recurring basis at December 31, 2008.

Description	December 31 2008	FIN No. 39 Netting[c]	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
			(millions)		
KCP&L					
Assets					
Derivative instruments [a]	$ 0.6	$ -	$ -	$ 0.6	$ -
Nuclear decommissioning trust [b]	95.2	-	52.9	35.5	6.8
Total	95.8	-	52.9	36.1	6.8
Liabilities					
Derivative instruments [a]	80.3	-	-	80.3	-
Total	$ 80.3	$ -	$ -	$ 80.3	$ -
Other Great Plains Energy					
Assets					
Derivative instruments [a]	$ 17.2	$ (0.7)	$ 3.2	$ 10.9	$ 3.8
SERP rabbi trust [b]	6.7	-	0.2	6.5	-
Total	23.9	(0.7)	3.4	17.4	3.8
Liabilities					
Derivative instruments [a]	5.9	(11.4)	10.1	7.2	-
Total	$ 5.9	$ (11.4)	$ 10.1	$ 7.2	$ -
Great Plains Energy					
Assets					
Derivative instruments [a]	$ 17.8	$ (0.7)	$ 3.2	$ 11.5	$ 3.8
Nuclear decommissioning trust [b]	95.2	-	52.9	35.5	6.8
SERP rabbi trust [b]	6.7	-	0.2	6.5	-
Total	119.7	(0.7)	56.3	53.5	10.6
Liabilities					
Derivative instruments [a]	86.2	(11.4)	10.1	87.5	-
Total	$ 86.2	$ (11.4)	$ 10.1	$ 87.5	$ -

(a) The fair value of derivative instruments is estimated using market quotes, net of estimated credit risk. Upon adoption of SFAS No. 157, the Company's own credit risk has been incorporated into the valuation of derivative liabilities. This had no impact to Great Plains Energy or KCP&L.

(b) Fair value is based on quoted market prices of the investments held by the fund and/or valuation models. The total does not include cash and cash equivalents, which are not subject to the fair value requirements of SFAS No. 157.

(c) Represents the difference between derivative contracts in an asset or liability position presented on a net basis by counterparty on the consolidated balance sheet where a master netting agreement exists between the Company and the counterparty. At December 31, 2008, Great Plains Energy netted $10.7 million of cash collateral posted with counterparties.

The following tables reconcile the beginning and ending balances for all level 3 assets and liabilities, net measured at fair value on a recurring basis for 2008.

Fair Value Measurements Using Significant Unobservable Inputs (Level 3)			
	KCP&L	Other Great Plains Energy	Great Plains Energy
Description	Nuclear Decommissioning Trust	Derivative Instruments	Total
		(millions)	
Balance January 1, 2008	$ 6.5	$ 22.4	$ 28.9
GMO acquisition July 14, 2008	-	6.6	6.6
Total realized/unrealized gains or (losses)			
Included in regulatory liability	(1.0)	-	(1.0)
Included in non-operating income	-	(1.8)	(1.8)
Purchase, issuances, and settlements	(2.5)	(1.0)	(3.5)
Transfers in and/or out of Level 3	3.8	(16.4)	(12.6)
Discontinued operations	-	(6.0)	(6.0)
Balance December 31, 2008	$ 6.8	$ 3.8	$ 10.6
Total unrealized gains and (losses) included in non-operating income relating to assets and liabilities still on the consolidated balance sheet at December 31, 2008	$ -	$ (2.3)	$ (2.3)

KCP&L's level 3 activity consists of mortgage-backed securities held by KCP&L's decommissioning trust fund. Other Great Plains Energy's level 3 activity consists almost entirely of forward physical derivative instruments held by MPS Merchant.

SFAS No. 157 is not yet effective for the Company's nonfinancial assets and liabilities measured at fair value on a nonrecurring basis, such as AROs, reporting units and long-lived asset groups measured at fair value for impairment testing, nonfinancial assets and liabilities measured at fair value in a business combination and not measured at fair value in subsequent periods. The effective date for these measurements has been delayed by FSP SFAS No. 157-2, "Effective Date of FASB Statement No. 157," to January 1, 2009, and interim periods within that fiscal year. Management has evaluated the impact of adoption to those nonfinancial assets and liabilities delayed by FSP SFAS No. 157-2 and has determined there is no significant impact on Great Plains Energy's and KCP&L's fair value measurement processes.

In January 2008, the FASB proposed FSP SFAS No. 157-c, "Measuring Liabilities under FASB Statement No. 157" to amend the standard to clarify the principles on fair value measurement of liabilities. Management is currently evaluating the impact of the proposed FSP with a final FSP expected in the first quarter of 2009.

In October 2008, the FASB issued FSP SFAS No. 157-3, "Determining the Fair Value of a Financial Asset When the Market for That Asset is Not Active," to clarify the application of fair value measurement in an inactive market and was effective upon issuance. Management has evaluated the FSP and determined there is no significant impact to the Company's fair value measurement processes.

22. TAXES

Components of income tax expense (benefit) are detailed in the following tables.

Great Plains Energy	2008	2007	2006
Current income taxes		(millions)	
Federal	$ (21.0)	$ 44.3	$ 59.2
State	1.1	6.5	0.9
Total	(19.9)	50.8	60.1
Deferred income taxes			
Federal	3.3	22.5	(7.2)
State	40.8	1.3	(3.8)
Total	44.1	23.8	(11.0)
Noncurrent income taxes [a]			
Federal	(0.6)	(0.7)	-
State	(1.0)	(0.9)	-
Total	(1.6)	(1.6)	-
Investment tax credit			
Deferral	74.2	-	-
Amortization	(1.8)	(1.5)	(1.2)
Total	72.4	(1.5)	(1.2)
Total income tax expense	95.0	71.5	47.9
Less: taxes on discontinued operations			
Current tax expense	25.8	5.4	16.3
Deferred tax expense (benefit)	4.5	21.4	(28.7)
Noncurrent income tax expense (benefit)	0.9	(0.2)	-
Income tax expense on continuing operations	$ 63.8	$ 44.9	$ 60.3

KCP&L	2008	2007	2006
Current income taxes		(millions)	
Federal	$ (8.0)	$ 38.7	$ 49.3
State	4.5	4.4	4.8
Total	(3.5)	43.1	54.1
Deferred income taxes			
Federal	(38.4)	17.7	15.6
State	30.9	2.0	1.8
Total	(7.5)	19.7	17.4
Noncurrent income taxes [a]			
Federal	(1.7)	(1.7)	-
State	(0.3)	(0.3)	-
Total	(2.0)	(2.0)	-
Investment tax credit			
Deferral	74.2	-	-
Amortization	(1.4)	(1.5)	(1.2)
Total	72.8	(1.5)	(1.2)
Total	$ 59.8	$ 59.3	$ 70.3

[a] For 2008 and 2007, this includes amounts recognized under FIN No. 48. Tax contingency reserves for 2006 are included in current income tax expense.

Income Tax Expense (Benefit) 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	**2008**	**2007**	**2006**	**2008**	**2007**	**2006**
		(millions)				
Federal statutory income tax	$ 64.2	$ 58.0	$ 68.9	35.0 %	35.0 %	35.0 %
Differences between book and tax depreciation not normalized	(5.4)	2.0	(0.3)	(2.9)	1.2	(0.2)
Amortization of investment tax credits	(1.8)	(1.5)	(1.2)	(1.0)	(0.9)	(0.6)
Federal income tax credits	(10.2)	(7.9)	(9.3)	(5.6)	(4.8)	(4.7)
State income taxes	3.2	(0.1)	2.3	1.8	(0.1)	1.2
Rate change on deferred taxes	19.3	-	-	10.5	-	-
Changes in uncertain tax positions, net [a]	0.1	0.6	0.8	0.1	0.3	0.4
GMO transaction costs	(1.9)	(3.7)	-	(1.0)	(2.2)	-
Other	(3.7)	(2.5)	(0.9)	(2.1)	(1.5)	(0.5)
Total	$ 63.8	$ 44.9	$ 60.3	34.8 %	27.0 %	30.6 %

	Income Tax Expense			Income Tax Rate		
KCP&L	**2008**	**2007**	**2006**	**2008**	**2007**	**2006**
		(millions)				
Federal statutory income tax	$ 64.7	$ 75.6	$ 76.9	35.0 %	35.0 %	35.0 %
Differences between book and tax depreciation not normalized	(5.2)	2.0	(0.3)	(2.8)	0.9	(0.2)
Amortization of investment tax credits	(1.4)	(1.5)	(1.2)	(0.8)	(0.7)	(0.6)
Federal income tax credits	(9.8)	(6.4)	(4.6)	(5.3)	(2.9)	(2.1)
State income taxes	3.8	4.7	5.5	2.1	2.2	2.5
Changes in uncertain tax positions, net [a]	(0.6)	(0.3)	0.6	(0.3)	(0.1)	0.3
Parent company tax benefits [b]	(6.7)	(12.0)	(4.7)	(3.6)	(5.6)	(2.1)
Rate change on deferred taxes	20.3	-	-	11.0	-	-
Other	(5.3)	(2.8)	(1.9)	(3.0)	(1.4)	(0.8)
Total	$ 59.8	$ 59.3	$ 70.3	32.3 %	27.4 %	32.0 %

[a] For 2008 and 2007, this includes amounts recognized under FIN No. 48.

[b] The tax sharing between Great Plains Energy and its subsidiaries was modified on July 14, 2008. As part of the new agreement, parent company tax benefits are no longer allocated to KCP&L or other subsidiaries.

SFAS No. 109, "Accounting for Income Taxes," requires companies to adjust deferred tax assets and liabilities to reflect tax rates that are anticipated to be in effect when timing differences reverse. Due to the sale of Strategic Energy during the second quarter of 2008, the composite tax rate for the companies is expected to increase as a result of the change in composition of states that Great Plains Energy conducts business. Therefore, deferred tax assets and liabilities have been adjusted to reflect the expected increase in the composite tax rate. The impact of the increase in the composite tax rate on deferred tax assets and liabilities resulted in tax expense for Great Plains Energy and KCP&L of $19.3 million and $20.3 million, respectively, at December 31, 2008.

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.

December 31	Great Plains Energy 2008	Great Plains Energy 2007	KCP&L 2008	KCP&L 2007
	(millions)			
Current deferred income taxes				
Net operating loss carryforward	$ 26.2	$ -	$ -	$ -
Other	5.9	3.6	4.9	3.4
Net current deferred income tax asset before valuation allowance	32.1	3.6	4.9	3.4
Valuation allowance	(3.5)	-	-	-
Net current deferred income tax asset	28.6	3.6	4.9	3.4
Noncurrent deferred income taxes				
Plant related	(775.2)	(573.7)	(599.3)	(573.7)
Income taxes on future regulatory recoveries	(122.5)	(66.5)	(71.6)	(66.5)
Derivative instruments	44.1	12.3	40.0	4.5
Pension and postretirement benefits	(6.9)	(23.3)	(9.9)	(25.8)
SO_2 emission allowance sales	32.4	33.4	34.6	33.4
Fuel clause adjustments	(20.4)	-	(0.6)	-
Transition costs	(18.2)	-	(11.4)	-
Tax credit carryforwards	140.3	19.2	36.4	-
Long-term debt fair value adjustment	45.3	-	-	-
Capital loss carryforwards	49.7	-	-	-
Net operating loss carryforward	315.2	0.4	-	-
Other	1.4	(9.4)	(14.4)	(14.1)
Net noncurrent deferred tax liability before valuation allowance	(314.8)	(607.6)	(596.2)	(642.2)
Valuation allowance	(72.3)	(0.4)	-	-
Net noncurrent deferred tax liability	(387.1)	(608.0)	(596.2)	(642.2)
Net deferred income tax liability	$ (358.5)	$ (604.4)	$ (591.3)	$ (638.8)

December 31	Great Plains Energy 2008	Great Plains Energy 2007	KCP&L 2008	KCP&L 2007
	(millions)			
Gross deferred income tax assets	$ 955.9	$ 222.3	$ 460.3	$ 183.0
Gross deferred income tax liabilities	(1,314.4)	(826.7)	(1,051.6)	(821.8)
Net deferred income tax liability	$ (358.5)	$ (604.4)	$ (591.3)	$ (638.8)

Tax Credit Carryforwards

At December 31, 2008, Great Plains Energy and KCP&L had $37.3 million and $36.4 million, respectively, of federal general business income tax credit carryforwards. These credits relate primarily to Advanced Coal Investment Tax Credits and expire in years 2021 to 2028. Approximately $0.5 million of these credits are related to Low Income Housing credits that were acquired from GMO. Due to federal limitations on the utilization of income tax attributes acquired in the GMO acquisition, management expects these credits to expire unutilized and has provided a valuation allowance against $0.5 million of the federal income tax benefit as discussed below.

At December 31, 2008, Great Plains Energy had $87.4 million of federal alternative minimum tax credit carryforwards that were acquired from GMO. These credits do not expire and can be used to reduce taxes paid in the future.

At December 31, 2008 and 2007, Great Plains Energy had $15.9 million and $19.2 million, respectively, of state income tax credit carryforwards. The state income tax credits relate primarily to the affordable housing investment portfolio, and the carryforwards expire in years 2010 to 2013. Management expects these credits will be fully utilized within the carryforward period.

Capital Loss Carryforwards

At December 31, 2008, after implementation of FIN No. 48, Great Plains Energy had approximately $49.7 million of tax benefits related to capital loss carryforwards that were acquired from GMO. The benefits from the capital loss carryforwards expire in 2009. These capital losses were treated as ordinary losses on filed income tax returns. The tax benefits from the ordinary losses on the returns as filed are included in unrecognized tax benefits for net operating loss carryforwards discussed below. If the unrecognized tax benefits from the net operating loss carryforwards are recognized, then the entire amount of recognized tax benefits from capital loss carryforwards will be reduced to zero. Management has provided a full valuation allowance for the $49.7 million of tax benefits related to capital loss carryforwards. Thus, any changes to unrecognized tax benefits impacting capital loss carryforwards will have an offsetting impact on the related valuation allowance.

Net Operating Loss Carryforwards

At December 31, 2008, after implementation of FIN No. 48, Great Plains Energy had $295.2 million of tax benefits related to federal net operating loss (NOL) carryforwards that were acquired from GMO. The tax benefits for NOLs originating in 1999 are $0.4 million, $86.1 million originating in 2003, $104.7 million originating in 2004, $74.1 million originating in 2005, and $82.3 originating in 2006. Great Plains Energy estimates that $52.4 million of federal tax liability related to 2008 will offset tax benefits from the 2003 NOL. The federal NOL carryforwards expire in years 2019 to 2026. Management expects to utilize all of these NOL carryforwards before they expire.

In addition, after implementation of FIN No. 48, Great Plains Energy also had deferred tax benefits of $46.2 million related to state NOLs as of December 31, 2008, $44.8 million of which were acquired from GMO. Management does not expect to utilize $25.6 million of NOLs in tax jurisdictions where the Company does not expect to operate in the future. Therefore, a valuation allowance has been provided against $25.6 million of state tax benefits, as discussed below.

If unrecognized tax benefits from federal and state NOLs are recognized, management expects that a valuation allowance will be needed for a portion of the tax benefits due to federal and state limitations on the utilization of income tax attributes acquired from GMO. It is reasonably possible that this valuation allowance will be recorded in 2009 and is expected to be recorded to the statement of operations in accordance with guidance in SFAS No. 141(revised 2007) "Business Combinations". The estimated valuation allowance adjustment is $56.0 million.

Valuation Allowances

Great Plains Energy is required to assess the ultimate realization of deferred tax assets using a "more likely than not" assessment threshold. This assessment takes into consideration tax planning strategies within Great Plains Energy's control. As a result of this assessment, Great Plains Energy has established a full valuation allowance against tax benefits from capital loss carryforwards, a partial valuation allowance for state tax NOL carryforwards, and a partial valuation allowance for tax credit carryforwards.

During 2008, $0.9 million of tax expense was recorded in continuing operations primarily related to a portion of the valuation allowance against state NOL carryforwards. The remaining valuation allowances against capital loss carryforwards, state NOL carryforwards, and general business credits were acquired from GMO and were recorded as a part of the purchase accounting entries impacting goodwill.

Uncertain Tax Positions

Great Plains Energy and KCP&L recognize tax benefits in accordance with FIN No. 48. FIN No. 48 establishes a "more-likely-than-not" recognition threshold that must be met before tax benefits can be recognized in the financial statements. Upon adoption of FIN No. 48 on January 1, 2007, Great Plains Energy recognized a $18.8 million increase in the liability for unrecognized tax benefits. This increase was offset by a $0.9 million decrease to the January 1, 2007, balance of retained earnings, a $17.9 million decrease in deferred taxes, a $4.0 million decrease in accrued taxes and a $4.0 million increase in accrued interest. KCP&L recognized a $19.8 million increase in the liability for unrecognized tax benefits that was offset by a $0.2 million decrease to the January 1, 2007, balance of retained earnings, a $15.7 million decrease in deferred taxes and a $3.9 million decrease in accrued taxes.

At December 31, 2008 and 2007, Great Plains Energy had $97.3 million and $21.9 million, respectively, of liabilities related to unrecognized tax benefits. Of this amount, $80.2 million at December 31, 2008, and $3.6 million at December 31, 2007, is expected to impact the effective tax rate if recognized. The $75.4 million increase in unrecognized tax benefits is primarily due to an increase of $77.0 million for unrecognized tax benefits acquired in the acquisition of GMO offset by a decrease of $8.5 million for unrecognized tax benefits due to the Joint Committee on Taxation approval on July 31, 2008, of the audit for the 2000-2003 tax years.

At December 31, 2008 and 2007, KCP&L had $17.6 million and $19.6 million, respectively, of liabilities related to unrecognized tax benefits. Of this amount, $1.2 million at December 31, 2008, and $1.3 million at December 31, 2007, is expected to impact the effective tax rate if recognized. The $2.0 million decrease in unrecognized tax benefits is primarily due to a decrease of $7.5 million of unrecognized tax benefits due to the Joint Committee on Taxation approval of the audit for the 2000-2003 tax years.

The following table reflects activity for Great Plains Energy and KCP&L related to the liability for unrecognized tax benefits.

	Great Plains Energy		KCP&L	
	2008	2007	2008	2007
	(millions)			
Balance at January 1	$ 21.9	$ 23.5	$ 19.6	$ 21.6
Additions for current year tax positions	5.3	4.1	3.8	2.9
Additions for prior year tax positions	2.6	0.1	2.6	0.1
Additions for GMO prior year tax positions	77.0	-	-	-
Reductions for prior year tax positions	(0.8)	(5.0)	(0.7)	(4.9)
Settlements	(8.5)	-	(7.5)	-
Statute expirations	(0.2)	(0.8)	(0.2)	(0.1)
Balance at December 31	$ 97.3	$ 21.9	$ 17.6	$ 19.6

With the adoption of FIN No. 48, Great Plains Energy and KCP&L elected to recognize interest accrued related to unrecognized tax benefits in interest expense and penalties in non-operating expenses. In 2008, Great Plains Energy and KCP&L recognized a reduction of $6.6 million and $1.7 million, respectively, of interest expense related to unrecognized tax benefits. The reduction in interest expense for both Great Plains Energy and KCP&L is related to the Joint Committee on Taxation approval of the audit for the 2000-2003 tax years. In 2007, Great Plains Energy and KCP&L recognized an increase of interest expense of $2.0 million and $1.0 million, respectively. At December 31, 2008 and 2007, accrued interest related to unrecognized tax benefits for Great Plains Energy was $2.6 million and $8.4 million, respectively. KCP&L had accrued interest related to unrecognized tax benefits of $1.7 million and $3.4 million at December 31, 2008 and 2007, respectively. Amounts accrued for penalties with respect to unrecognized tax benefits are insignificant.

In January 2009, the Company agreed to IRS audit adjustments for the Great Plains Energy and subsidiaries 2004 tax year and the GMO and subsidiaries 2003 and 2004 tax years. As a result of the Great Plains Energy agreement, the amount of unrecognized tax benefits that will be recognized in the first quarter of 2009 is $2.1 million for Great Plains Energy and KCP&L. The IRS audit adjustments and agreement for GMO 2003 and 2004 tax years must be approved by the Joint Committee on Taxation. The Joint Committee on Taxation is expected to make a decision on its approval before the statute of limitations for 2003 to 2004 is scheduled to expire on December 31, 2009. If the agreement is approved, Great Plains Energy expects to recognize $74.5 million of unrecognized tax benefits offset by a $56.0 million increase in the valuation allowance for NOLs, and a $2.5 million decrease in deferred income tax assets, which is estimated to result in a $16.0 million increase in net income. The Company also estimates that it is reasonably possible that $5.2 million for Great Plains Energy and $3.8 million for KCP&L of unrecognized tax benefits will reverse in the next twelve months due statute expirations or settlement agreements with tax authorities.

Great Plains Energy files a consolidated federal income tax return as well as unitary and combined income tax returns in several state jurisdictions with Kansas and Missouri being the most significant. The Company also files separate company returns in Canada and certain other states. The IRS audit agreement for GMO for the 2003 and 2004 tax year remains subject to Joint Committee on Taxation approval and the IRS has commenced an audit of Great Plains Energy in its subsidiaries for the 2006 tax year. This audit is expected to be completed by the end of 2009.

Advanced Coal Credit

On April 28, 2008, KCP&L was notified that its application filed in 2007 for $125.0 million in advanced coal investment tax credits (ITC) was approved by the IRS. The credit is based on the amount of expenses incurred on the construction of Iatan No. 2. Additionally, in order to meet the advanced clean coal standards and avoid forfeiture and/or the recapture of tax credits in the future, KCP&L must meet or exceed certain environmental performance standards for at least five years once the plant is placed in service. As a result, Great Plains Energy and KCP&L recognized federal tax benefits related to costs incurred to date on the plant of $74.2 million at December 31, 2008. However, tax laws require the companies to reduce income tax expense for ratemaking and financial statement purposes ratably over the life of the plant. Therefore, Great Plains Energy and KCP&L concurrently recognized deferred ITC expense of $74.2 million for 2008. Great Plains Energy and KCP&L will recognize the tax benefits of the ITC over the life of the plant once it is placed in service.

23. SEGMENTS AND RELATED INFORMATION

Great Plains Energy

Great Plains Energy has one reportable segment based on its method of internal reporting, which generally segregates reportable segments based on products and services, management responsibility and regulation. The one reportable business segment is electric utility, consisting of KCP&L and GMO's regulated utility operations. For periods prior to 2008, the electric utility segment is the same as the previously reported KCP&L segment. Other includes GMO activity other than its regulated utility operations, HSS, Services, KLT Inc. (including Strategic Energy discontinued operations), 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 the reportable segment. For segment reporting, the segment's income taxes include the effects of allocating holding company tax benefits prior to July 14, 2008. GMO is only included from the date of acquisition, July 14, 2008, through December 31, 2008. Segment performance is evaluated based on net income.

The following tables reflect summarized financial information concerning Great Plains Energy's reportable segment.

2008	Electric Utility	Other	Great Plains Energy
		(millions)	
Operating revenues	$ 1,670.1	$ -	$ 1,670.1
Depreciation and amortization	(235.0)	-	(235.0)
Interest charges	(96.9)	(14.4)	(111.3)
Income taxes	(70.9)	7.1	(63.8)
Loss from equity investments	-	(1.3)	(1.3)
Discontinued operations	-	35.0	35.0
Net income	143.1	11.4	154.5

2007	Electric Utility	Other	Great Plains Energy
		(millions)	
Operating revenues	$ 1,292.7	$ -	$ 1,292.7
Depreciation and amortization	(175.6)	-	(175.6)
Interest charges	(67.2)	(24.7)	(91.9)
Income taxes	(59.3)	14.4	(44.9)
Loss from equity investments	-	(2.0)	(2.0)
Discontinued operations	-	38.3	38.3
Net income	156.8	2.4	159.2

2006	Electric Utility	Other	Great Plains Energy
		(millions)	
Operating revenues	$ 1,140.4	$ -	$ 1,140.4
Depreciation and amortization	(152.7)	-	(152.7)
Interest charges	(60.9)	(9.2)	(70.1)
Income taxes	(71.6)	11.3	(60.3)
Loss from equity investments	-	(1.9)	(1.9)
Discontinued operations	-	(9.1)	(9.1)
Net income (loss)	149.6	(22.0)	127.6

	Electric Utility	Other	Eliminations	Great Plains Energy
2008		(millions)		
Assets	$ 8,161.9	$ 141.7	$ (434.3)	$ 7,869.3
Capital expenditures [a]	1,023.7	1.2	-	1,024.9
2007				
Assets [b]	$ 4,290.7	$ 551.2	$ (9.8)	$ 4,832.1
Capital expenditures [a]	511.5	4.4	-	515.9
2006				
Assets [b]	$ 3,858.0	$ 501.5	$ (0.6)	$ 4,358.9
Capital expenditures [a]	476.0	4.1	-	480.1

[a] Includes capital expenditures from discontinued operations of $0.8 million, $3.7 million and $3.9 million for 2008, 2007 and 2006, respectively.

[b] Other includes assets of discontinued operations.

KCP&L

For 2008, KCP&L has one reportable segment, KCP&L, which is the same as the KCP&L registrant financial statements for 2008. The following tables reflect summarized financial information concerning KCP&L's reportable segment for 2007 and 2006. For the periods prior to the January 2, 2008, transfer of HSS to KLT Inc., other included HSS and intercompany eliminations. Intercompany eliminations include insignificant amounts of intercompany financing-related activities.

2007	KCP&L	Other	Consolidated KCP&L
		(millions)	
Operating revenues	$ 1,292.7	$ -	$ 1,292.7
Depreciation and amortization	(175.6)	-	(175.6)
Interest charges	(67.2)	-	(67.2)
Income taxes	(59.3)	-	(59.3)
Net income (loss)	156.8	(0.1)	156.7

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

	KCP&L	Other	Consolidated KCP&L
2007		(millions)	
Assets	$ 4,290.7	$ 1.3	$ 4,292.0
Capital expenditures	511.5	-	511.5
2006			
Assets	$ 3,858.0	$ 1.5	$ 3,859.5
Capital expenditures	476.0	-	476.0

24. DISCONTINUED OPERATIONS

Strategic Energy

In 2007, Great Plains Energy retained Merrill Lynch & Co. as financial advisor to assist in a review of strategic and structural alternatives for its Strategic Energy subsidiary. In April 2008, the Board of Directors approved management's recommendation to sell Strategic Energy and Great Plains Energy entered into an agreement with Direct Energy Services, LLC (Direct Energy), a subsidiary of Centrica plc, under which Direct Energy acquired all of Great Plains Energy's interest in Strategic Energy. On June 2, 2008, Great Plains Energy completed the sale of Strategic Energy. Great Plains Energy received gross cash proceeds of $307.7 million, including the base purchase price of $300.0 million plus a working capital adjustment of $7.7 million. In accordance with SFAS No. 144, Strategic Energy is reported as discontinued operations for the periods presented.

Under the terms of the purchase agreement with Direct Energy, Great Plains Energy indemnifies Direct Energy for various matters, including: breaches of representations, warranties and covenants; funds advanced by Strategic Energy to certain of its channel partners if such funds become uncollectible before December 2, 2009, (approximately $8 million, excluding commission offsets); and losses associated with litigation and other certain claims to the extent such losses exceed $7.5 million in the aggregate. Great Plains Energy has reserved $2.0 million with respect to the indemnification obligations.

The following table summarizes the income (loss) from Strategic Energy's discontinued operations.

	2008	2007	2006
		(millions)	
Revenues	$ 667.4	$ 1,974.4	$ 1,534.9
Income (loss) from operations before income taxes [a]	$ 182.4	$ 64.9	$ (21.5)
Income (loss) on disposal before income taxes	(116.2)	-	-
Total income (loss) on discontinued operations before income taxes	66.2	64.9	(21.5)
Income taxes	(31.2)	(26.6)	12.4
Income (loss) from discontinued operations, net of income taxes	$ 35.0	$ 38.3	$ (9.1)

[a] For 2008, amount includes $189.1 million, of unrealized net gains related to derivative contracts.

The following table provides additional information regarding the net cash proceeds and loss on sale of Strategic Energy.

Sale of Strategic Energy			
		(millions)	
Net cash proceeds			$ 273.1
Income taxes on sale			34.6
Gross cash proceeds			307.7
Net assets of discontinued operations at December 31, 2007	$ 233.7		
Intercompany liabilities not in discontinued operations	(3.0)		
Income taxes on parent included in discontinued operations	6.2		
Book value of investment in Strategic Energy at December 31, 2007		$ 236.9	
Increase (decrease) to book value:			
Net income [a]		187.8	
Change in OCI		(14.2)	
Equity contribution from parent		14.4	
Distributions to parent		(3.0)	
Book value of investment in Strategic Energy at June 2, 2008			421.9
Reserve for indemnification obligations			2.0
Loss on disposal before income taxes			$ (116.2)

[a] Amount includes $189.1 million of unrealized net gains related to derivatives contracts.

Strategic Energy's assets and liabilities of discontinued operations are summarized in the following table.

	December 31 2007
Assets	(millions)
Cash	$ 43.1
Restricted cash	0.7
Receivables, net	261.4
Deferred income taxes	16.2
Derivative instruments	52.7
Nonutility property	6.8
Goodwill	88.1
Other	18.1
Total assets of discontinued operations	$ 487.1
Liabilities	
Accounts payable	$ 165.1
Accrued taxes	10.8
Derivative instruments	38.2
Deferred income taxes	16.8
Other	22.5
Total liabilities of discontinued operations	$ 253.4
Net assets of discontinued operations	$ 233.7

25. JOINTLY OWNED ELECTRIC UTILITY PLANTS

Great Plains Energy's and KCP&L's share of jointly owned electric utility plants at December 31, 2008, is detailed in the following table.

Great Plains Energy

	Wolf Creek Unit	LaCygne Units	Iatan No. 1 Unit	Iatan No. 2 Unit	Iatan Common	Jeffrey Energy Center
			(millions, except MW amounts)			
Great Plains Energy's share	47%	50%	88%	73%	79%	8%
Utility plant in service	$ 1,405.1	$ 397.1	$ 348.5	$ -	$ -	$ 110.8
Accumulated depreciation	732.9	273.8	253.1	-	-	72.6
Nuclear fuel, net	63.9	-	-	-	-	-
Construction work in progress	25.9	11.5	294.3	738.2	217.5	38.5
2009 accredited capacity-MWs	545	709	621	NA	NA	174

KCP&L

	Wolf Creek Unit	LaCygne Units	Iatan No. 1 Unit	Iatan No. 2 Unit	Iatan Common
		(millions, except MW amounts)			
KCP&L's share	47%	50%	70%	55%	61%
Utility plant in service	$ 1,405.1	$ 397.1	$ 279.3	$ -	$ -
Accumulated depreciation	732.9	273.8	203.2	-	-
Nuclear fuel, net	63.9	-	-	-	-
Construction work in progress	25.9	11.5	225.4	567.3	175.5
2009 accredited capacity-MWs	545	709	494	NA	NA

Each owner must fund its own portion of the plant's operating expenses and capital expenditures. KCP&L's and GMO's share of direct expenses is included in the appropriate operating expense classifications in Great Plains Energy's and KCP&L's financial statements.

26. NEW ACCOUNTING STANDARDS

SFAS No. 141(R)

In December 2007, the FASB issued SFAS No. 141(R). This statement significantly changes how business combinations are accounted for in current practice. Changes to current practice include, among other things, requiring all assets acquired and liabilities assumed in a business combination to be measured at fair value in accordance with SFAS No. 157 as of the acquisition date, an acquirer to expense transaction costs and equity securities issued as consideration in a business combination be recorded at fair value as of the acquisition date. The provisions of this statement are effective for Great Plains Energy and KCP&L prospectively for business combinations occurring on or after January 1, 2009, except it requires the prospective application of the provisions related to income taxes to business combinations occurring in 2008. Among the SFAS No. 141(R) provisions related to income taxes that are effective for the GMO acquisition, any adjustments to GMO's deferred tax assets and uncertain tax position balances that occur after the measurement period, which is limited to a maximum of one year from the acquisition date, will be recorded as a component of income tax expense as required by the standard. Management does not expect any other significant impacts on the acquisition of GMO as a result of this standard.

27. QUARTERLY OPERATING RESULTS (UNAUDITED)

Great Plains Energy	Quarter 1st	2nd	3rd	4th
2008	(millions, except per share amounts)			
Operating revenue	$ 297.6	$ 335.0	$ 593.6	$ 443.9
Operating income	19.1	51.6	169.6	34.7
Income (loss) from continuing operations	(5.4)	13.2	104.7	7.0
Net income (loss)	47.5	(5.0)	105.0	7.0
Basic and diluted earnings (loss) per common share from continuing operations	(0.07)	0.15	0.92	0.06
Basic and diluted earnings (loss) per common share	0.55	(0.06)	0.92	0.06
2007				
Operating revenue	$ 255.7	$ 319.1	$ 416.0	$ 301.9
Operating income	9.7	65.1	121.7	60.0
Income (loss) from continuing operations	(3.7)	32.4	66.0	26.2
Net income	23.4	25.6	62.1	48.1
Basic and diluted earnings (loss) per common share from continuing operations	(0.05)	0.37	0.77	0.30
Basic and diluted earnings per common share	0.28	0.29	0.72	0.56

KCP&L	Quarter 1st	2nd	3rd	4th
2008	(millions)			
Operating revenue	$ 297.6	$ 335.0	$ 423.7	$ 286.7
Operating income	29.4	52.5	127.9	28.3
Net income	17.0	7.9	83.9	16.4
2007				
Operating revenue	$ 255.7	$ 319.1	$ 416.0	$ 301.9
Operating income	13.1	70.1	127.0	68.7
Net income	2.0	36.5	76.6	41.6

Quarterly data is subject to seasonal fluctuations with peak periods occurring in the summer months.

Due to the June 2008 sale of Strategic Energy discussed in Note 24, Strategic Energy is reported as discontinued operations in accordance with SFAS No. 144. The following table provides information to reconcile Great Plains Energy's 1st quarter 2008 operating results above to the amount originally reported.

1st Quarter 2008	Previously Reported	Adjustment	As Adjusted
	(millions, except per share amounts)		
Operating revenue	$ 825.4	$ (527.8)	$ 297.6
Operating income	108.4	(89.3)	19.1
Income (loss) from continuing operations	47.5	(52.9)	(5.4)
Net income	47.5	-	47.5
Basic and diluted earnings (loss) per common share from continuing operations	0.55	(0.62)	(0.07)
Basic and diluted earnings per common share	0.55	-	0.55

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, 2008 and 2007, and the related consolidated statements of income, comprehensive income, common shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2008. 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 these 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 the Company as of December 31, 2008 and 2007, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2008, 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 10 to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standard (SFAS) No, 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans — an amendment of FASB Statements No. 87,88,106, and 132(R)* on December 31, 2006. As discussed in Note 22 to the consolidated financial statements, the Company adopted Financial Accounting Standards Board Interpretation (FIN) No. 48 *Accounting for Uncertainty in Income Taxes — an interpretation of FASB Statement No. 109* on January 1, 2007.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2008, 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, 2009, expressed an unqualified opinion on the Company's internal control over financial reporting (which report did not include an assessment on the internal control over financial reporting at KCP&L Greater Missouri Operations).

/s/DELOITTE & TOUCHE LLP

Kansas City, Missouri
February 27, 2009

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, 2008 and 2007, 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, 2008. Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement 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 the Company as of December 31, 2008 and 2007, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2008, 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 10 to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standard (SFAS) No, 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans — an amendment of FASB Statements No. 87,88,106, and 132(R)* on December 31, 2006. As discussed in Note 22 to the consolidated financial statements, the Company adopted Financial Accounting Standards Board Interpretation (FIN) No. 48 *Accounting for Uncertainty in Income Taxes — an interpretation of FASB Statement No. 109* on January 1, 2007.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2008, 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, 2009, expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/DELOITTE & TOUCHE LLP

Kansas City, Missouri
February 27, 2009

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 carried out evaluations of its 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 Great Plains Energy's management, including the chief executive officer and chief financial officer, and Great Plains Energy's disclosure committee. Based upon these evaluations, the chief executive officer and chief financial officer of Great Plains Energy have concluded as of the end of the period covered by this report that the disclosure controls and procedures of Great Plains Energy were effective at a reasonable assurance level.

Changes in Internal Control Over Financial Reporting

There has been no change in Great Plains Energy's internal control over financial reporting that occurred during the quarterly period ended December 31, 2008, 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.

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, 2008. Management used for this evaluation the framework in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations (COSO) of the Treadway Commission. Great Plains Energy excluded from its evaluation GMO's internal control over financial reporting, which was acquired on July 14, 2008. GMO's total assets, revenues and net income constituted 33%, 20% and 8%, respectively, of Great Plains Energy's consolidated financial statement amounts as of and for the year ended December 31, 2008. Great Plains Energy will include GMO in its evaluation of the design and effectiveness of internal control over financial reporting as of December 31, 2009.

Management has concluded that, as of December 31, 2008, 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 report on Great Plain's Energy's internal control over financial reporting, 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 the internal control over financial reporting of Great Plains Energy Incorporated and subsidiaries (the "Company") as of December 31, 2008, 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, included in the accompanying *Management's Report on Internal Control Over Financial Reporting.* Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

As described in *Management's Report on Internal Control Over Financial Reporting*, management excluded from its assessment the internal control over financial reporting at KCP&L Greater Missouri Operations (GMO), which was acquired on July 14, 2008. GMO's total assets, revenues and net income constituted 33%, 20%, and 8%, respectively, of the Great Plains Energy consolidated financial statement amounts as of and for the year ended December 31, 2008. Accordingly, our audit did not include the internal control over financial reporting at GMO.

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, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, 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, 2008, of the Company and our report dated February 27, 2009, 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, 2009

ITEM 9A (T). CONTROLS AND PROCEDURES

Disclosure Controls and Procedures
KCP&L carried out evaluations of its 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 KCP&L's management, including the chief executive officer and chief financial officer, and KCP&L's disclosure committee. Based upon these evaluations, the chief executive officer and chief financial officer of KCP&L have concluded as of the end of the period covered by this report that the disclosure controls and procedures of KCP&L were effective at a reasonable assurance level.

Changes in Internal Control Over Financial Reporting
There has been no change in KCP&L's internal control over financial reporting that occurred during the quarterly period ended December 31, 2008, 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.

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, 2008. 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, 2008, 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 report on KCP&L's internal control over financial reporting, 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 the internal control over financial reporting of Kansas City Power & Light Company and subsidiaries (the "Company") as of December 31, 2008, 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, included in the accompanying *Management's Report on Internal Control Over Financial Reporting.* Our responsibility is to express an opinion on 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, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, 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, 2008 of the Company and our report dated February 27, 2009 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 27, 2009

ITEM 9B. OTHER INFORMATION

None.

Form 10-K

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 2009 Proxy Statement (Proxy Statement), which will be filed with the SEC no later than April 30, 2009:

- Information regarding the directors of Great Plains Energy required by this item is contained in the Proxy Statement sections 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 "Security Ownership of Certain Beneficial Owners, Directors and Officers - Section 16(a) Beneficial Ownership Reporting Compliance."
- Information regarding the Code of Ethics and 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 Ethical Business Conduct (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 contained in the sections titled "Executive Compensation," "Director Compensation," "Compensation Discussion and Analysis", "Compensation Committee Report" and "Director Independence – Compensation Committee Interlocks and insider Participation" 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 Plans
The information required by this item regarding Great Plains Energy's equity compensation plans 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 section titled "Director Independence" and "Related Party 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 "Ratification of Appointment of Independent Auditors" 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 2008 and 2007 and for other services rendered during 2008 and 2007 on behalf of KCP&L and its subsidiaries, as well as all out-of-pocket costs incurred in connection with these services:

Fee Category	2008	2007
Audit Fees	$ 1,086,087	$ 1,020,636
Audit-Related Fees	97,372	59,000
Tax Fees	32,561	36,689
All Other Fees	-	-
Total Fees	$ 1,216,020	$ 1,116,325

Audit Fees: Consists of fees billed for professional services rendered for the audits of the annual consolidated financial statements of KCP&L 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 SEC, including comfort letters, consents and assistance with and review of documents filed with the SEC; 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.

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 registered public accounting firm 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 registered public accounting firm. 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. 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 reports at each regular meeting 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.

Form 10-K

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

Financial Statements

Financial Statement Schedules

Exhibits

Great Plains Energy Documents

Exhibit Number		Description of Document
2.1.1	*	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).
2.1.2	*	Mutual Notice of Extension among Aquila, Inc., Great Plains Energy Incorporated, Gregory Acquisition Corp., and Black Hills Corporation dated as of January 31, 2008 (Exhibit 2.1.2 to Form 10-K for the year ended December 31, 2007).
2.1.3	*	Mutual Notice of Extension among Aquila, Inc., Great Plains Energy Incorporated, Gregory Acquisition Corp., and Black Hills Corporation dated as of April 29, 2008 (Exhibit 10.1 to Form 8-K dated April 7, 2008).
3.1.1	*	Articles of Incorporation of Great Plains Energy Incorporated dated as of February 26, 2001 and corrected as of October 13, 2006 (Exhibit 3.1 to Form 10-Q for the quarter ended September 30, 2006).
3.1.2	*	By-laws of Great Plains Energy Incorporated, as amended December 2, 2008 (Exhibit 3.1 to Form 8-K dated December 8, 2008).
4.1.1	*	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).
4.1.2	*	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).
4.1.3	*	Second Supplemental Indenture dated as of September 25, 2007, between Great Plains Energy Incorporated and The Bank of New York Trust Company, N.A., as trustee (Exhibit 4.1 to Form 8-K dated September 25, 2007).
4.1.4	*	Indenture, dated as of August 24, 2001, between Aquila, Inc. and BankOne Trust Company, N.A., as Trustee (Exhibit 4(d) to Registration Statement on Form S-3 (File No. 333-68400) filed by Aquila, Inc. on August 27, 2001).
4.1.5	*	Second Supplemental Indenture, dated as of July 3, 2002, between Aquila, Inc. and BankOne Trust Company, N.A., as Trustee related to 11.875% Senior Notes due July 1, 2012. (Exhibit 4(c) to Form S-4 (File No. 333-100204) filed by Aquila, Inc. on September 30, 2002).
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 as amended May 1, 2007 (Exhibit 10.1 to Form 8-K filed May 4, 2007).
10.1.3	* +	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).
10.1.4	* +	Great Plains Energy Incorporated Long-Term Incentive Plan Awards Standards and Performance Criteria Effective as of May 6, 2008 (Exhibit 10.1.25 to Form 10-Q for the quarter ended June 30, 2008).

10.1.5	* +	Form of 2005 three-year 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).
10.1.6	* +	Form of 2006 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).
10.1.7	* +	Form of Restricted Stock Agreement Pursuant to the Great Plains Energy Incorporated Long-Term Incentive Plan Effective May 7, 2002 (Exhibit 10.1.6 to Form 10-K for the year ended December 31, 2006).
10.1.8	* +	Form of 2008 Restricted Stock Agreement (Exhibit 10.1.20 to Form 10-Q for the quarter ended June 30, 2008).
10.1.9	* +	Form of 2005 three-year Performance Share Agreement Pursuant to the Great Plains Energy Incorporated Long-Term Incentive Plan Effective May 7, 2002 (Exhibit 10.1.a to Form 10-Q for the quarter ended March 31, 2005).
10.1.10	* +	Form of 2006 three-year 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).
10.1.11	* +	Form of 2007 three-year Performance Share Agreement Pursuant to the Great Plains Energy Incorporated Long-Term Incentive Plan Effective May 7, 2002 for Great Plains Energy and KCP&L officers (Exhibit 10.1.10 to Form 10-K for the year ended December 31, 2006).
10.1.12	* +	Form of 2007 three-year Performance Share Agreement Pursuant to the Great Plains Energy Incorporated Long-Term Incentive Plan Effective May 7, 2002 for Strategic Energy officers (Exhibit 10.1.11 to Form 10-K for the year ended December 31, 2006).
10.1.13	* +	Form of 2008 three-year Performance Share Agreement (Exhibit 10.1.21 to Form 10-Q for the quarter ended June 30, 2008).
10.1.14	* +	Form of Amendment to 2003 Stock Option Grants (Exhibit 10.1.9 to Form 10-Q for the quarter ended September 30, 2007).
10.1.15	* +	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).
10.1.16	* +	Strategic Energy, L.L.C. Executive Committee Long-Term Incentive Plan dated as of January 1, 2007, (Exhibit 10.1.6 to Form 10-Q for the quarter ended June 30, 2007).
10.1.17	* +	Aquila, Inc. 2002 Omnibus Incentive Compensation Plan (Exhibit 10.3 to Form 10-Q for the quarter ended September 30, 2002, filed by Aquila, Inc.).
10.1.18	* +	Great Plains Energy Incorporated Kansas City Power & Light Company Annual Incentive Plan amended effective as of January 1, 2007, and 2008 objectives adopted as of May 6, 2008 (Exhibit 10.1.22 to Form 10-Q for the quarter ended June 30, 2008).
10.1.19	* +	Strategic Energy, L.L.C. Executive Committee Annual Incentive Plan dated as of January 1, 2007 (Exhibit 10.3 to Form 8-K filed May 4, 2007).
10.1.20	* +	Form of Indemnification Agreement with each officer and director (Exhibit 10-f to Form 10-K for year ended December 31, 1995).
10.1.21	* +	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).

10.1.22	* +	Form of Indemnification Agreement with each director and officer (Exhibit 10.1 to Form 8-K dated December 8, 2008).
10.1.23	* +	Form of Indemnification Agreement with officers and directors (Exhibit 10.1.p to Form 10-K for the year ended December 31, 2005).
10.1.24	* +	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).
10.1.25	* +	Form of Change in Control Severance Agreement with William H. Downey (Exhibit 10.1.b to Form 10-Q for the quarter ended September 30, 2006).
10.1.26	* +	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).
10.1.27	* +	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).
10.1.28	* +	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).
10.1.29	+	Great Plains Energy Incorporated Supplemental Executive Retirement Plan (As Amended and Restated for I.R.C. §409A), as amended February 10, 2009.
10.1.30	* +	Great Plains Energy Incorporated Nonqualified Deferred Compensation Plan (As Amended and Restated for I.R.C. §409A) (Exhibit 10.1.10 to Form 10-Q for the quarter ended September 30, 2007)
10.1.31	+	Description of Compensation Arrangements with Directors and Certain Executive Officers.
10.1.32	* +	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).
10.1.33	* +	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).
10.1.34	* +	Letter regarding enhanced supplemental retirement and severance benefit for William H. Downey, dated August 5, 2008) (Exhibit 10.1.23 to Form 10-Q for the quarter ended June 30, 2008).
10.1.35	+	Employment offer letters to Michael J. Chesser dated September 10 and September 16, 2003.
10.1.36	*	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).
10.1.37	*	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).
10.1.38	*	Letter Agreement dated as of June 29, 2007 to Asset Purchase Agreement and Partnership Interests Purchase Agreement by and among Aquila, Inc., Black Hills Corporation, Great Plains Energy Incorporated, and Gregory Acquisition Corp., dated February 6, 2007 (Exhibit 10.1.1 to Form 10-Q for the quarter ended June 30, 2007).

10.1.39 * Letter Agreement dated as of August 31, 2007, to Asset Purchase Agreement and Partnership Interests Purchase Agreement by and among Aquila, Inc., Black Hills Corporation, Great Plains Energy Incorporated and Gregory Acquisition Corp (Exhibit 10.1.4 to Form 10-Q for the quarter ended September 30, 2007).

10.1.40 * Letter Agreement dated as of September 28, 2007, to Asset Purchase Agreement and Partnership Interests Purchase Agreement by and among Aquila, Inc., Black Hills Corporation, Great Plains Energy Incorporated and Gregory Acquisition Corp (Exhibit 10.1.5 to Form 10-Q for the quarter ended September 30, 2007).

10.1.41 * Letter Agreement dated as of October 3, 2007, to Agreement and Plan of Merger, Asset Purchase Agreement and Partnership Interests Purchase Agreement by and among Aquila, Inc., Black Hills Corporation, Great Plains Energy Incorporated and Gregory Acquisition Corp (Exhibit 10.1.6 to Form 10-Q for the quarter ended September 30, 2007).

10.1.42 * Letter Agreement dated as of November 30, 2007, to Asset Purchase Agreement and Partnership Interests Purchase Agreement by and among Aquila, Inc., Black Hills Corporation, Great Plains Energy Incorporated and Gregory Acquisition Corp. (Exhibit 10.1.40 to Form 10-K for the year ended December 31, 2007).

10.1.43 * Letter Agreement dated as of January 30, 2008, to Asset Purchase Agreement and Partnership Interests Purchase Agreement by and among Aquila, Inc., Black Hills Corporation, Great Plains Energy Incorporated and Gregory Acquisition Corp. (Exhibit 10.1.41 to Form 10-K for the year ended December 31, 2007).

10.1.44 * Letter Agreement dated as of February 28, 2008, to Asset Purchase Agreement and Partnership Interests Purchase Agreement by and among Aquila, Inc., Black Hills Corporation, Great Plains Energy Incorporated and Gregory Acquisition Corp. (Exhibit 10.1.3 to Form 10-Q for the quarter ended March 31, 2008).

10.1.45 * Letter Agreement dated as of March 28, 2008, to Asset Purchase Agreement and Partnership Interests Purchase Agreement by and among Aquila, Inc., Black Hills Corporation, Great Plains Energy Incorporated and Gregory Acquisition Corp. (Exhibit 10.1.4 to Form 10-Q for the quarter ended March 31, 2008).

10.1.46 * Letter Agreement dated as of April 28, 2008, to Asset Purchase Agreement and Partnership Interests Purchase Agreement by and among Aquila, Inc., Black Hills Corporation, Great Plains Energy Incorporated and Gregory Acquisition Corp. (Exhibit 10.1.5 to Form 10-Q for the quarter ended March 31, 2008).

10.1.47 * Letter Agreement dated as of May 29, 2008, to Asset Purchase Agreement and Partnership Interests Purchase Agreement by and among Aquila, Inc., Black Hills Corporation, Great Plains Energy Incorporated and Gregory Acquisition Corp. (Exhibit 10.1.5 to Form 10-Q for the quarter ended June 30, 2008).

10.1.48 * Letter Agreement dated as of June 19, 2008, to Asset Purchase Agreement and Partnership Interests Purchase Agreement by and among Aquila, Inc., Black Hills Corporation, Great Plains Energy Incorporated and Gregory Acquisition Corp. (Exhibit 10.1.6 to Form 10-Q for the quarter ended June 30, 2008).

10.1.49 * Letter Agreement dated as of June 27, 2008, to Asset Purchase Agreement and Partnership Interests Purchase Agreement by and among Aquila, Inc., Black Hills Corporation, Great Plains Energy Incorporated and Gregory Acquisition Corp. (Exhibit 10.1.7 to Form 10-Q for the quarter ended June 30, 2008).

10.1.50	*	Joint Motion and Settlement Agreement dated as of February 26, 2008, among Great Plains Energy Incorporated, Kansas City Power & Light Company, the Kansas Corporation Commission Staff, the Citizens' Utility Ratepayers Board, Aquila, Inc. d/b/a Aquila Networks, Black Hills Corporation, and Black Hills/Kansas Gas Utility Company, LLC (Exhibit 10.1.7 to Form 10-Q for the quarter ended March 31, 2008).
10.1.51	*	Purchase Agreement, dated as of April 1, 2008, by and among Custom Energy Holdings, L.L.C., Direct Energy Services, LLC and Great Plains Energy Incorporated (Exhibit 10.1 to Form 8-K filed April 2, 2008).
10.1.52	*	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).
10.1.53	*	Notice of Election to Transfer Unused Commitment between the Great Plains Energy Incorporated and Kansas City Power & Light Company Credit Agreements dated as of May 11, 2006, with Bank of America, N.A., as Administrative Agent, JPMorgan Chase Bank, N.A., as Syndication Agent, BNP Paribas, The Bank of Tokyo-Mitsubishi UFJ, Limited, Chicago Branch and Wachovia Bank N.A., as Co-Documentation Agents, The Bank of New York, KeyBank National Association, The Bank of Nova Scotia, UMB Bank, N.A., and Commerce Bank, N.A. (Exhibit 10.1.2 to Form 10-Q for the quarter ended June 30, 2007).
10.1.54	*	First Amendment to Credit Agreement dated as of May 16, 2008, among Great Plains Energy Incorporated, the Lenders party thereto and Bank of America, N.A., as Administrative Agent (Exhibit 10.1 to Form 8-K filed on May 22, 2008)
10.1.55	*	Second Amendment to Credit Agreement dated as of May 16, 2008, among Great Plains Energy Incorporated, the Lenders party thereto and Bank of America, N.A., as Administrative Agent (Exhibit 10.2 to Form 8-K filed on May 22, 2008).
10.1.56	*	Third Amendment to Credit Agreement dated as of June 13, 2008, among Great Plains Energy Incorporated, the Lenders party thereto and Bank of America, N.A., as Administrative Agent (Exhibit 10.1 to Form 8-K filed on June 19, 2008).
10.1.57	*	Financing Agreement dated as of April 22, 2005, among Aquila, Inc., the lenders from time to time party thereto, and Union Bank of California, N.A., as agent (Exhibit 10.1 to Form 8-K filed by Aquila, Inc. on April 26, 2005).
10.1.58	*	Amendment No. 2 to Financing Agreement dated December 9, 2006, by and between Aquila, Inc., the lenders from time to time party thereto, and Union Bank of California, N.A., as agent (Exhibit 10.1 to Form 8-K filed by Aquila, Inc. on December 11, 2006).
10.1.59	*	Amendment to Financing Agreement dated June 10, 2008, by and among Aquila, Inc., the lenders from time to time party thereto, and Union Bank of California, N.A., as agent (Exhibit 10.1.3 to Form 10-Q for the quarter ended September 30, 2008).
10.1.60		Amendment to Financing Agreement dated October 28, 2008, by and among KCP&L Greater Missouri Operations Company, the lenders from time to time party thereto, and Union Bank of California, N.A., as agent

10.1.61	*	Guaranty dated as of July 14, 2008, between Great Plains Energy Incorporated and Union Bank of California, N.A., related to Financing Agreement dated as of April 22, 2005, as amended, among Aquila, Inc., the lenders from time to time party thereto, and Union Bank of California, N.A. as Agent. (Exhibit 10.1 to Form 8-K filed July 18, 2008).
10.1.62	*	Guaranty dated as of July 15, 2008, issued by Great Plains Energy Incorporated in favor of Union Bank of California, N.A., as successor trustee, and the holders of the Aquila, Inc., 11.875% Senior Notes due July 1, 2012. (Exhibit 10.3 to Form 8-K filed July 18, 2008).
10.1.63	*	Guaranty dated as of July 15, 2008, issued by Great Plains Energy Incorporated in favor of Union Bank of California, N.A., as successor trustee, and the holders of the Aquila, Inc., 7.75% Senior Notes due June 15, 2011. (Exhibit 10.4 to Form 8-K filed July 18, 2008).
10.1.64	*	Guaranty dated as of July 15, 2008, issued by Great Plains Energy Incorporated in favor of Union Bank of California, N.A., as successor trustee, and the holders of the Aquila, Inc., 7.95% Senior Notes due February 1, 2011. (Exhibit 10.5 to Form 8-K filed July 18, 2008).
10.1.65	*	Guaranty dated as of July 15, 2008, issued by Great Plains Energy Incorporated in favor of Union Bank of California, N.A., as successor trustee, and the holders of the Aquila, Inc., 8.27% Senior Notes due November 15, 2021. (Exhibit 10.6 to Form 8-K filed July 18, 2008).
10.1.66	*	Guaranty dated as of July 15, 2008, issued by Great Plains Energy Incorporated in favor of Union Bank of California, N.A., as successor trustee, and the holders of the Aquila, Inc., 7.625% Senior Notes due November 15, 2009. (Exhibit 10.7 to Form 8-K filed July 18, 2008).
10.1.67	*	Credit Agreement dated as of September 23, 2008, among Aquila, Inc., as the Borrower, Great Plains Energy Incorporated, as the Guarantor, certain lenders, Bank of America, N.A., as Administrative Agent, Union Bank of California, N.A., as Syndication Agent and BNP Paribas, JPMorgan Chase Bank, N.A. and The Royal Bank of Scotland plc as Co-Documentation Agents, Banc of America Securities LLC and Union Bank of California, N.A., as Joint Lead Arrangers and Joint Book Managers. (Exhibit 10.1 to Form 8-K filed on September 23, 2008).
10.1.68	*	Sales Agency Financing Agreement dated August 14, 2008 between Great Plains Energy Incorporated and BNY Mellon Capital Markets, LLC. (Exhibit 1.1 to Form 8-K filed August 14, 2008).
12.1		Computation of Ratio of Earnings to Fixed Charges.
21.1		List of Subsidiaries of Great Plains Energy Incorporated.
23.1		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
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 April 1, 2008 (Exhibit 3.2. to Form 8-K dated April 7, 2008).
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).

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4.2.11	*	Indenture dated as of May 1, 2007, between Kansas City Power & Light Company and The Bank of New York Trust Company, N.A., as trustee (Exhibit 4.1 to Form 8-K dated June 4, 2007).
4.2.12	*	Supplemental Indenture No. 1 dated as of June 4, 2007 between Kansas City Power & Light Company and The Bank of New York Trust Company, N.A., as trustee (Exhibit 4.2 to Form 8-K dated June 4, 2007).
4.2.13	*	Supplemental Indenture No. 2 dated as of March 11, 2008, between Kansas City Power & Light Company and The Bank of New York Trust Company, N.A., as trustee (Exhibit 4.2 to Form 8-K dated March 11, 2008).
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	*	Insurance Agreement dated as of September 19, 2007, by and between Financial Guaranty Insurance Company and Kansas City Power & Light Company (Exhibit 10.2.2 1 to Form 10Q for the quarter ended September 30, 2007).
10.2.6	*	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).
10.2.7	*	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).
10.2.8	*	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).

10.2.9 * Notice of Election to Transfer Unused Commitment between the Great Plains Energy Incorporated and Kansas City Power & Light Company Credit Agreements dated as of May 11, 2006, with Bank of America, N.A., as Administrative Agent, JPMorgan Chase Bank, N.A., as Syndication Agent, BNP Paribas, The Bank of Tokyo-Mitsubishi UFJ, Limited, Chicago Branch and Wachovia Bank N.A., as Co-Documentation Agents, The Bank of New York, KeyBank National Association, The Bank of Nova Scotia, UMB Bank, N.A., and Commerce Bank, N.A. (Exhibit 10.1.2 to Quarterly Report on Form 10-Q for the quarter ended June 30, 2007).

10.2.10 * 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).

10.2.11 * 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).

10.2.12 * Joint Motion and Settlement Agreement dated as of February 26, 2008, among Great Plains Energy Incorporated, Kansas City Power & Light Company, the Kansas Corporation Commission Staff, the Citizens' Utility Ratepayers Board, Aquila, Inc. d/b/a Aquila Networks, Black Hills Corporation, and Black Hills/Kansas Gas Utility Company, LLC (Exhibit 10.1.7 to Form 10-Q for the quarter ended March 31, 2008).

10.2.13 * 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).

10.2.14 * 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).

10.2.15 * Amendment No. 1 dated as of April 2, 2007, among Kansas City Power & Light Receivables Company, Kansas City Power & Light Company, The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch and Victory Receivables Corporation to the Receivables Sale Agreement dated as of July 1, 2005 (Exhibit 10.2.2 to Form 10-Q for the quarter ended March 31, 2007).

10.2.16 * Amendment No. 2 dated as of July 11, 2008, among Kansas City Power & Light Receivables Company, Kansas City Power & Light Company, The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch and Victory Receivables Corporation to the Receivables Sale Agreement dated as of July 1, 2005 (Exhibit 10.2.2 to For 10-Q for the quarter ended June 30, 2008).

10.2.17 * Collaboration Agreement dated as of March 19, 2007, among Kansas City Power & Light Company, Sierra Club and Concerned Citizens of Platte County, Inc (Exhibit 10.1 to Form 8-K filed on March 20, 2007).

10.2.18 * Joint Operating Agreement between Kansas City Power & Light Company and Aquila, Inc., dated as of October 10, 2008 (Exhibit 10.2.1 to Form 10-Q for the quarter ended September 30, 2008).

10.2.19	* +	Great Plains Energy Incorporated Kansas City Power & Light Company Annual Incentive Plan amended effective as of January 1, 2007, and 2008 objectives adopted as of May 6, 2008 (Exhibit 10.1.22 to Form 10-Q for the quarter ended June 30, 2008).
10.2.20	+	Agreement between Kansas City Power & Light Company and Stephen T. Easley dated December 2, 2008.
10.2.21	+	Employment offer letter to John R. Marshall dated April 7, 2005.
12.2		Computation of Ratio of Earnings to Fixed Charges.
23.2		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.

+ 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 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	2008	2007	2006
Operating Expenses	(millions, except per share amounts)		
Selling, general and administrative	$ **9.3**	$ 18.5	$ 7.1
Maintenance	**1.0**	0.8	-
General taxes	**0.8**	0.3	0.3
Total	**11.1**	19.6	7.4
Operating loss	**(11.1)**	(19.6)	(7.4)
Equity in earnings from subsidiaries	**144.8**	156.8	152.1
Non-operating income	**0.6**	4.2	1.1
Interest charges	**(19.2)**	(26.8)	(8.9)
Income from continuing operations before income taxes	**115.1**	114.6	136.9
Income taxes	**4.4**	6.3	(0.2)
Income from continuing operations	**119.5**	120.9	136.7
Equity in earnings from discontinued subsidiary	**35.0**	38.3	(9.1)
Net income	**154.5**	159.2	127.6
Preferred stock dividend requirements	**1.6**	1.6	1.6
Earnings available for common shareholders	$ **152.9**	$ 157.6	$ 126.0
Average number of basic common shares outstanding	**101.1**	84.9	78.0
Average number of diluted common shares outstanding	**101.2**	85.2	78.2
Basic earnings (loss) per common share			
Continuing operations	$ **1.16**	$ 1.41	$ 1.74
Discontinued operations	**0.35**	0.45	(0.12)
Basic earnings per common share	$ **1.51**	$ 1.86	$ 1.62
Diluted earnings (loss) per common share			
Continuing operations	$ **1.16**	$ 1.40	$ 1.73
Discontinued operations	**0.35**	0.45	(0.12)
Diluted earnings per common share	$ **1.51**	$ 1.85	$ 1.61
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	2008	2007
ASSETS	(millions, except share amounts)	
Current Assets		
Cash and cash equivalents	$ 12.0	$ 6.6
Accounts receivable from subsidiaries	4.8	1.0
Notes receivable from subsidiaries	0.6	0.6
Taxes receivable	12.0	3.7
Deferred income taxes	0.2	-
Other	0.4	0.4
Total	30.0	12.3
Nonutility Property and Investments		
Investment in KCP&L	1,621.9	1,479.4
Investment in discontinued operations	-	233.7
Investments in other subsidiaries	1,094.8	23.1
Other	1.0	0.7
Total	2,717.7	1,736.9
Deferred Charges and Other Assets		
Deferred income taxes	1.2	8.0
Other	5.0	23.7
Total	6.2	31.7
Total	$ 2,753.9	$ 1,780.9

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	2008	2007
LIABILITIES AND CAPITALIZATION	(millions, except share amounts)	
Current Liabilities		
Notes payable	**$ 30.0**	$ 42.0
Accounts payable to subsidiaries	**28.7**	10.8
Accounts payable	**1.3**	0.1
Accrued interest	**2.0**	2.0
Other	**0.8**	1.3
Derivative instruments	**-**	16.4
Total	**62.8**	72.6
Deferred Credits and Other Liabilities		
Payable to subsidiaries	**-**	0.2
Other	**1.9**	1.7
Total	**1.9**	1.9
Capitalization		
Common shareholders' equity		
Common stock-150,000,000 shares authorized without par value		
119,375,923 and 86,325,136 shares issued, stated value	**2,118.4**	1,065.9
Retained earnings	**489.3**	506.9
Treasury stock-120,677 and 90,929 shares, at cost	**(3.6)**	(2.8)
Accumulated other comprehensive loss	**(53.5)**	(2.1)
Total	**2,550.6**	1,567.9
Cumulative preferred stock $100 par value		
3.80% - 100,000 shares issued	**10.0**	10.0
4.50% - 100,000 shares issued	**10.0**	10.0
4.20% - 70,000 shares issued	**7.0**	7.0
4.35% - 120,000 shares issued	**12.0**	12.0
Total	**39.0**	39.0
Long-term debt	**99.6**	99.5
Total	**2,689.2**	1,706.4
Commitments and Contingencies		
Total	**$ 2,753.9**	$ 1,780.9

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	2008	2007	2006
Cash Flows from Operating Activities		(millions)	
Net income	**$ 154.5**	$ 159.2	$ 127.6
Adjustments to reconcile income to net cash from operating activities:			
Amortization	**0.9**	1.0	0.6
Deferred income taxes, net	**3.3**	(6.2)	-
Equity in earnings from subsidiaries	**(144.8)**	(156.8)	(152.1)
Equity in earnings from discontinued operations	**(35.0)**	(38.3)	9.1
Cash flows affected by changes in:			
Accounts receivable from subsidiaries	**(26.3)**	0.6	(0.6)
Taxes receivable	**(8.7)**	(1.8)	(0.1)
Accounts payable to subsidiaries	**17.7**	(4.8)	15.1
Other accounts payable	**0.2**	0.1	(0.1)
Accrued interest	**-**	1.1	(0.1)
Cash dividends from subsidiaries	**416.7**	159.7	118.0
Other	**2.7**	1.8	1.7
Net cash from operating activities	**381.2**	115.6	119.1
Cash Flows from Investing Activities			
Equity contributions to subsidiaries	**(200.0)**	(94.0)	(134.6)
Net change in notes receivable from subsidiaries	**-**	1.7	3.1
GMO acquisition	**(5.0)**	-	-
Purchases of nonutility property	**(0.3)**	(0.7)	-
Net cash from investing activities	**(205.3)**	(93.0)	(131.5)
Cash Flows from Financing Activities			
Issuance of common stock	**15.3**	10.5	153.6
Issuance of long-term debt	**-**	99.5	-
Issuance fees	**(1.0)**	(1.4)	(5.7)
Net change in notes payable to subsidiaries	**-**	(13.2)	13.2
Net change in short-term borrowings	**(12.0)**	42.0	(6.0)
Equity forward settlement	**-**	(12.3)	-
Dividends paid	**(172.0)**	(144.5)	(132.7)
Other financing activities	**(0.8)**	(2.4)	(6.2)
Net cash from financing activities	**(170.5)**	(21.8)	16.2
Net Change in Cash and Cash Equivalents	**5.4**	0.8	3.8
Cash and Cash Equivalents at Beginning of Year	**6.6**	5.8	2.0
Cash and Cash Equivalents at End of Year	**$ 12.0**	$ 6.6	$ 5.8

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, 2008, 2007 and 2006

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, 2008					
Allowance for uncollectible accounts	$ 4.3	$ 7.6	$ 6.8 [a]	$ 11.9 [b]	$ 6.8
Legal reserves	2.2	8.3	9.5 [c]	9.8 [d]	10.2
Environmental reserves	0.3	-	0.2 [c]	-	0.5
Uncertain tax positions [e]	7.9	1.8	74.9 [c]	5.9 [f]	78.7
Tax valuation allowance	-	0.9	74.9 [c]	-	75.8
Year Ended December 31, 2007					
Allowance for uncollectible accounts	$ 4.2	$ 5.4	$ 2.9 [a]	$ 8.2 [b]	$ 4.3
Legal reserves	3.9	1.9	-	3.6 [c]	2.2
Environmental reserves	0.3	-	-	-	0.3
Uncertain tax positions [e]	4.2	2.5	1.9 [g]	0.7 [f]	7.9
Year Ended December 31, 2006					
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 [e]	3.4	1.0	-	0.2 [f]	4.2

[a] Recoveries. Charged to other accounts for the year ended December 31, 2008, includes the establishment of an allowance of $1.1 million and a $1.4 million increase due to the acquisition of GMO. Charged to other accounts for the year ended December 31, 2006, includes the establishment of an allowance of $1.5 million.

[b] Uncollectible accounts charged off.

[c] Acquisition of GMO.

[d] Payment of claims.

[e] Represents the total amount of tax expense that would impact the effective tax rate, if recognized, and amounts accrued for interest expense related to uncertain tax positions, net of tax.

[f] Reversal of uncertain tax positions and related interest.

[g] Upon adoption of FIN No. 48 on January 1, 2007, $1.7 million was charged to retained earnings.

Kansas City Power & Light Company
Valuation and Qualifying Accounts
Years Ended December 31, 2008, 2007 and 2006

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, 2008					
Allowance for uncollectible accounts	$ 4.3	$ 5.9	$ 3.3 [a]	$ 12.3 [b]	$ 1.2
Legal reserves	2.2	3.2	-	3.0 [c]	2.4
Environmental reserves	0.3	-	-	-	0.3
Uncertain tax positions [d]	3.0	-	-	1.2 [e]	1.8
Year Ended December 31, 2007					
Allowance for uncollectible accounts	$ 4.2	$ 5.4	$ 2.9 [a]	$ 8.2 [b]	$ 4.3
Legal reserves	3.9	1.9	-	3.6 [c]	2.2
Environmental reserves	0.3	-	-	-	0.3
Uncertain tax positions [d]	1.8	0.7	0.8 [f]	0.3 [e]	3.0
Year Ended December 31, 2006					
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 [d]	1.2	0.8	-	0.2 [e]	1.8

(a) Recoveries. Charged to other accounts for the year ended December 31, 2006, includes the establishment of an allowance of $1.5 million.

(b) Uncollectible accounts charged off.

(c) Payment of claims.

(d) Represents the total amount of tax expense that would impact the effective tax rate, if recognized, and amounts accrued for interest expense related to uncertain tax positions, net of tax.

(e) Reversal of uncertain tax positions and related interest.

(f) Upon adoption of FIN No. 48 on January 1, 2007, $0.8 million was charged to retained earnings.

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, 2009

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	Vice President and Controller (Principal Accounting Officer)	
David L. Bodde*	Director	February 27, 2009
/s/William H. Downey William H. Downey	Director	
Randall C. Ferguson, Jr.*	Director	
Gary D. Forsee*	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, 2009

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	Vice President and Controller (Principal Accounting Officer)	
David L. Bodde*	Director	February 27, 2009
/s/ William H. Downey William H. Downey	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*

Exhibit 31.1.a

CERTIFICATIONS

I, Michael J. Chesser, certify that:

1. I have reviewed this annual report on Form 10-K of Great Plains Energy Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report:

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 27, 2009

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

Exhibit 31.1.b

CERTIFICATIONS

I, Terry Bassham, certify that:

1. I have reviewed this annual report on Form 10-K of Great Plains Energy Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report:

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 27, 2009

/s/ Terry Bassham
Terry Bassham
Executive Vice President – Finance and Strategic Development and Chief Financial Officer

Directors and Officers

BOARD OF DIRECTORS:
GREAT PLAINS ENERGY

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

William H. Downey
President and Chief Operating Officer

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

Randall C. Ferguson, Jr.
Former Senior Partner for Business Development, Tshibanda & Associates, LLC, a consulting and project management services firm

Gary D. Forsee
President, University of Missouri System, the state's premier public institution of higher learning

Luis A. Jimenez
Senior Advisor for Arthur D. Little, Inc., an international management consultancy

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

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

Dr. Linda H. Talbott
President and CEO, Talbott & Associates, consultants in strategic planning, philanthropic management and development to foundations, corporations and nonprofit organizations

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

OFFICERS:
GREAT PLAINS ENERGY

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

William H. Downey
President and Chief Operating Officer

Terry D. Bassham
Executive Vice President-Finance and Strategic Development and Chief Financial Officer

Barbara B. Curry
Senior Vice President-Human Resources and Corporate Secretary

Michael W. Cline
Vice President-Investor Relations and Treasurer

William G. Riggins
General Counsel and Chief Legal Officer

Lori A. Wright
Vice President and Controller

Mark G. English
Assistant General Counsel and Assistant Secretary

OFFICERS:
KCP&L

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

William H. Downey
President and Chief Operating Officer

Terry D. Bassham
Executive Vice President-Finance and Strategic Development and Chief Financial Officer

John R. Marshall
Executive Vice President-Utility Operations

Barbara B. Curry
Senior Vice President-Human Resources and Corporate Secretary

Michael L. Deggendorf
Senior Vice President-Delivery

Scott H. Heidtbrink
Senior Vice President-Supply

Jim D. Alberts
Vice President-Customer Service

Kevin E. Bryant
Vice President-Energy Solutions

Lora C. Cheatum
Vice President-Procurement

Carl D. Churchman
Vice President-Construction

Michael W. Cline
Vice President-Investor Relations and Treasurer

Dana Crawford
Vice President-Strategic Operations Support

Chris B. Giles
Vice President-Regulatory Affairs

William P. Herdegen, III
Vice President-T&D Operations

Todd A. Kobayashi
Vice President-Strategy and Risk Management

William G. Riggins
General Counsel and Chief Legal Officer

Marvin L. Rollison
Vice President-Renewables and Gas Generation

Richard A. Spring
Vice President-Transmission Policy, Planning and Compliance

Charles H. Tickles
Vice President-Information Technology

Lori A. Wright
Vice President and Controller

Mark G. English
Assistant General Counsel and Assistant Secretary

Shareholder Information

GREAT PLAINS ENERGY FORM 10-K
Great Plains Energy's 2008 annual report on Form 10-K filed with the Securities and Exchange Commission can be found at *www.greatplainsenergy.com*. The required Sarbanes-Oxley Section 302 certifications were filed as exhibits to the 10-K. The 10-K is available at no charge upon written request to:

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

MARKET INFORMATION
Great Plains Energy common stock is traded on the New York Stock Exchange under the ticker symbol GXP. We had 30,142 shareholders of record as of February 24, 2009.

INTERNET SITE
We have a Web site on the Internet at *www.greatplainsenergy.com*. Information available includes our SEC filings, Company news releases, stock quotes, customer account information, community and environmental efforts, and information of general interest to investors and customers.

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

COMMON STOCK DIVIDENDS PAID

Quarter	2008	2007
First	$0.415	$0.415
Second	0.415	0.415
Third	0.415	0.415
Fourth	0.415	0.415

CUMULATIVE PREFERRED STOCK DIVIDENDS
Quarterly dividends on preferred stock were declared in each quarter of 2008 and 2007 as follows:

Series	Amount	Series	Amount
3.80%	$0.95	4.35%	$1.0875
4.20%	1.05	4.50%	1.125

TWO-YEAR COMMON STOCK HISTORY

	2008		2007	
Quarter	High	Low	High	Low
First	$28.85	$24.35	$32.67	$30.42
Second	26.76	24.67	33.18	28.82
Third	26.20	21.92	29.94	26.99
Fourth	22.43	17.09	30.45	28.32

ANNUAL MEETING OF SHAREHOLDERS
Great Plains Energy's annual meeting of shareholders will be held at 10 a.m., May 5, 2009, at Kansas City Public Library Plaza Branch, Truman Forum Auditorium, 4801 Main Street, Kansas City, Mo. 64112.

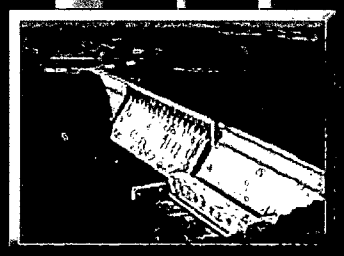
REGISTERED SHAREHOLDER INQUIRIES
For account information or assistance, including change of address, stock transfers, dividend payments, duplicate accounts or to report a lost certificate, please contact Investor Relations at 800-245-5275.

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

TRANSFER AGENT AND STOCK REGISTRANT
Computershare Trust Company, N.A.
Investor Services
P.O. Box 43078
Providence, RI 02940-3078
Tel: 800-884-4225

CORPORATE GOVERNANCE LISTING STANDARDS CERTIFICATION
On May 9, 2008, the Company submitted its Annual CEO Certification to the New York Stock Exchange (NYSE). Mike Chesser, Chairman of the Board and Chief Executive Officer of the Company, certified that as of May 9, 2008, he was not aware of any violation by the Company of NYSE Corporate Governance listing standards.

NYSE: GXP For more information on Great Plains Energy or KCP&L, visit us online at:
www.greatplainsenergy.com or *www.KCPL.com*

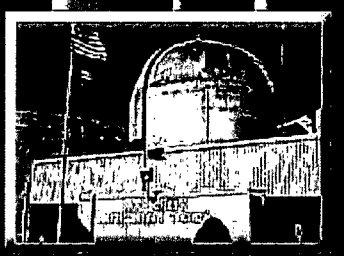


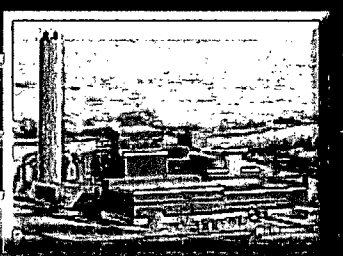
2008 Annual Report

KEPCo

Kansas Electric Power Cooperative, Inc.

A Touchstone Energy® Cooperative





Contents

KEPCo Staff

Stephen Parr ..... Executive Vice President & Chief Executive Officer

Mark Barbee ..... Vice President of Engineering, KSI Vice President of Engineering

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

Sam Delap ..... Information System Specialist

Terry Deutscher ..... EMS/SCADA System Specialist

Carol Gardner ..... Operations Analyst

Robert Hammersmith ... SCADA/Metering Technician 2

Shari Koch ... Accounting, Payroll & Benefits Specialist

Elizabeth Lesline ..... Administrative Assistant/ Receptionist

Mitch Long ..... Sr. SCADA/Metering Technician

Michael Morris ..... Sr. SCADA/Metering Technician

Erika Old ..... Finance & Benefits Analyst 2

Matt Ottman ..... Engineer 3

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, Government Affairs & Business Development

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 115,000 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 650 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

2008 Message

from

Kenneth J. Maginley
KEPCo President

Stephen E. Parr
Executive Vice President
& Chief Executive Officer


Mr. Maginley and Mr. Parr

A probable consensus of industry and individuals alike would be that 2008 was a year that is best forgotten, but unfortunately, will be remembered for decades to come. Climate concerns, stock market decline, credit tightening, rising unemployment, housing crisis, and bailouts were issues that enveloped our great country in a cloak of fear and despair.

The new administration in Washington, D.C. has a daunting task over the next four years to chart a course that leads the nation back to prosperity. Measures were taken by Congress to shore-up several companies whose financial failure could have precipitated a global economic catastrophe. However, the other maladies plaguing the U.S. and global economies appear to be deeply entrenched and from all indications, will continue to be so for a protracted period of time.

KEPCo has been able to shield itself from the hardships facing many companies and industries. The availability of credit has substantially tightened and the cost of capital has dramatically increased, causing pause for companies considering capital investment projects. In addition, the valuations of many publicly-traded companies have been adversely impacted as well, thus making it even more difficult to access capital. As a not-for-profit membership corporation, KEPCo does not have stockholders or a relationship with Wall Street. KEPCo continues to have access to affordable capital through Rural Utilities Service (RUS) and the National Rural Utilities Cooperative Finance Corporation. The access to affordable capital has been a key component in KEPCo's ability to keep rates stable for over two decades.

A carbon constrained world appears to be the future. Much speculation and anxiety surrounds the enactment of a cap and trade policy by Congress as an effort to reduce carbon dioxide and other greenhouse gas emissions. The enactment of such a policy has the potential to raise energy prices substantially. Many utilities have an eighty-five to one hundred percent exposure to greenhouse gas emitting resources, comprised primarily of coal and natural gas. KEPCo is in a unique position regarding efforts to reduce carbon emissions. Approximately fifty percent of KEPCo's generation resources, Wolf Creek and hydroelectric power through SWPA and WAPA, do not emit any greenhouse gases. As such, KEPCo's greenhouse gas exposure will only be on the purchase power agreements it has with area utilities, thus substantially softening the economic impact of any cap and trade or carbon tax policy to KEPCo's Member Cooperatives and their respective Members.

Increases in purchased power costs, as well as operations and maintenance costs, predicated the need for

KEPCo to file for a rate increase in late 2007. In June 2008, KEPCo reached a settlement with the Kansas Corporation Commission (KCC), without a formal hearing. The KCC granted KEPCo a 5.2% increase which will enable KEPCo to continue to meet its mortgage obligations with RUS and to remain in a solid financial state.

For over two years, KEPCo worked diligently with Westar Energy, Inc. on a thirty-eight year Purchase Power Agreement (PPA). In August 2007, KEPCo and Westar agreed upon the terms of the contract and filed the contract with FERC for approval. Subsequent negotiations with numerous parties continued through September 2008 when a settlement was filed with FERC. The formula-based PPA follows the actual cost to supply energy rather than a market-based pricing of energy. Once approved, the new contract will enable KEPCo and its Members access to Westar's existing low-cost generating resources and mitigate the risk of being vulnerable to price fluctuations in the open market.

In November, the Wolf Creek Nuclear Operating Corporation received a twenty-year license extension to 2045 from the Nuclear Regulatory Commission for the continued operation of the Wolf Creek Nuclear Generating Station in Burlington, KS. Wolf Creek came on line in 1985 and has been a cornerstone in providing safe, reliable, economical energy for KEPCo's Member Cooperatives. This license extension is invaluable to KEPCo's continued mission of providing reliable energy at a reasonable price.

2008-09 KEPCo Executive Committee (seated): Scott Whittington; Larry Stevens; Robert Reece; (standing) Stephen Parr, Executive Vice President & CEO; Kenneth Maginley, President; Kirk Thompson, Vice President; Dale Short, Secretary; and Kevin Compton, Treasurer.

Construction of Iatan 2 continues to progress and is on schedule for commercial operation the summer of 2010. Iatan 2 will be a state of the art, high efficiency coal plant utilizing the latest clean coal technology for environmental controls. KEPCo's 30 MW ownership of the plant will be an additional resource in ensuring a continued reliable, economical, and diversified power supply portfolio for KEPCo's Members.

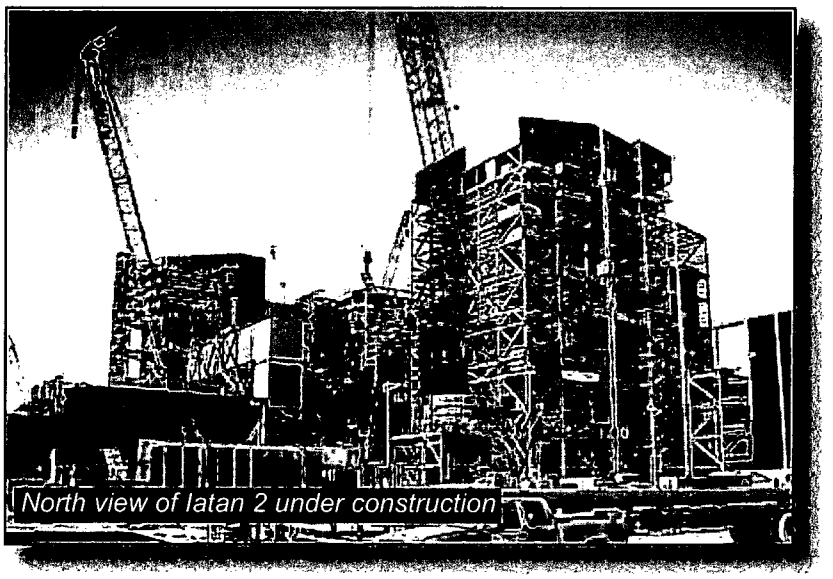
Sales and earnings for companies around the world continue to disappoint, as evidenced in the U.S. by poor GDP numbers. The economy in Kansas started to mirror the rest of the nation in the third and fourth quarters. KEPCo witnessed a slowing of ethanol production, a tightening of discretionary spending, and an impetus towards energy efficiency. Even with the economic and lifestyle changes that have been exhibited, KEPCo's energy sales continue to show an upward trend, increasing four percent over 2007. KEPCo attributes this trend to the continued demand of consumer electronic products, the change from natural gas as the fuel of choice for heating, both home and water, to electricity, and the change from natural gas-fired irrigation to electricity.

Another relatively mild summer, as was the case in 2007, caused peak demand to remain steady at 407.6

Continued on page 12

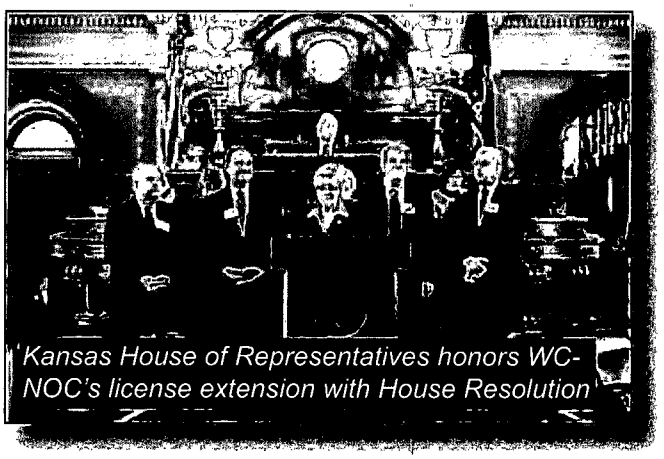
2008 KEPCo Highlights

After receiving a lien accommodation from RUS, KEPCo finalized a $75 million long-term loan from CFC to finance KEPCo's 30 MW share of Iatan 2. The ownership participation in Iatan 2 is a key component in KEPCo's energy resource mix. In a time of market uncertainty and market-based energy prices, the opportunity to own an economical and reliable generation resource is of tremendous value.


North view of Iatan 2 under construction

In August, a settlement on KEPCo's new long-term power purchase agreement with Westar Energy was filed at FERC. Implementation of this new, cost-based contract is anticipated in 2009.

KEPCo received a record amount of hydroelectric power, saving Members an estimated $4 million.


Kansas House of Representatives honors WCNOC's license extension with House Resolution

In September, KEPCo implemented new rates, including a purchased power demand adjuster, through a successful rate case filing with the Kansas Corporation Commission (KCC).

Wolf Creek Nuclear Generating Station continues to be a safe and economical resource for KEPCo's Members and has run continuously since completing refueling outage 16 in the spring of 2008. In November, WCNOC received a twenty-year license extension to 2045 from the NRC.

KEPCo continues to actively support SPP's efforts to assure adequate transmission is available in Kansas and successfully obtained approval from the SPP for firm long-term transmission service for Member load in the Aquila North (MKEC) service territory.

KEPCo continues to fund and assist Members in the promotion of an energy efficient electric water heater and heating/cooling system rebate program. Since inception, KEPCo has issued over 5,500 heating/cooling rebates and over 14,000 water heater rebates.


Kansas electric cooperative representatives with Senator Pat Roberts

KEPCo continues to work diligently with KEC and Sunflower on legislative issues in Kansas and in Washington, D.C. KEPCo testified on numerous pieces of legislation in 2008 and tracked several House and Senate bills. In Washington, D.C., KEPCo participated in the NRECA Legislative Conference.


Mr. Russ Wasson, NRECA, conducts financial retreat for KEPCo Trustees

KEPCo conducted a retreat for KEPCo Trustees that focused on the financial challenges facing the electric utility industry and KEPCo.

Four projects were selected by USDA for REDLG funding. The total combined project costs equal $8,030,102 with $2,072,200 being zero interest financing. These four projects created sixty-one new jobs.

KEPCo continues to support critical energy issues in the state through appointments by the Governor to special working groups and boards such as the Kansas Electric Transmission Authority and the Kansas Wind Working Group.

KSI Engineering assisted several cooperatives with ice storm damage assessments and FEMA reporting procedures.

KEPCo Staff worked safely with no lost time or recordable accidents.


KSI Engineering Staff assess ice storm damage

KEPCo Member Cooperatives Trustees, Alternates and Managers


Joseph Seiwert

Ark Valley Electric Cooperative Assn., Inc.
PO Box 1246, Hutchinson, KS 67504
620-662-6661
Trustee Rep. -- Joseph Seiwert
Alternate Trustee Rep. -- Bob Hall
Manager -- Bob Hall


Bob Hall

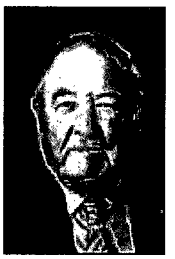

Ken Maginley

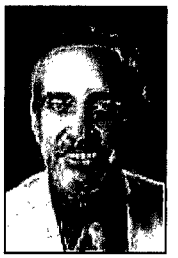
Bluestem Electric Cooperative, Inc.
PO Box 5, Wamego, KS 66547 785-456-2212
PO Box 513, Clay Center, KS 67432 785-632-3111
Trustee Rep. -- Kenneth J. Maginley
Alternate Trustee Rep. -- Robert M. Ohlde
Manager -- Kenneth J. Maginley


Bob Ohlde


Kevin Compton

Brown-Atchison Electric Cooperative Assn., Inc.
PO Box 230, Horton, KS 66439 785-486-2117
Trustee Rep. -- Kevin D. Compton
Alternate Trustee Rep. -- Dale Bodenhausen
Manager -- Rodney V. Gerdes


Dale Bodenhausen


Rod Gerdes


Dale Short

Butler Rural Electric Cooperative Assn., Inc.
PO Box 1242, El Dorado, KS 67042 316-321-9600
Trustee Rep. -- Dale Short
Alternate Trustee Rep. -- Richard Pearson
Manager -- Dale Short


Richard Pearson

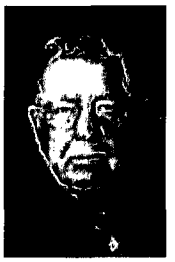

Dwane Kessinger

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
Trustee Rep. -- Dennis Peckman
Alternate Trustee Rep. -- Dale Coomes
Manager -- Dale Coomes


Dale Coomes


Larry Stevens

LJEC
PO Box 70, McLouth, KS 66054 913-796-6111
Trustee Rep. -- Larry H. Stevens
Alternate Trustee Rep. -- Steven Foss
Manager -- Steven Foss


Steven Foss


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


Donald Metzen

Sedgwick County Electric Cooperative Assn., Inc.
PO Box 220, Cheney, KS 67025 316-542-3131
Trustee Rep. -- Donald Metzen
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 368, Altamont, KS 67330 620-784-5500
Trustee Rep. -- Bryan W. Coover
Alternate Trustee Rep. -- Ron Holsteen
Manager -- Ron Holsteen

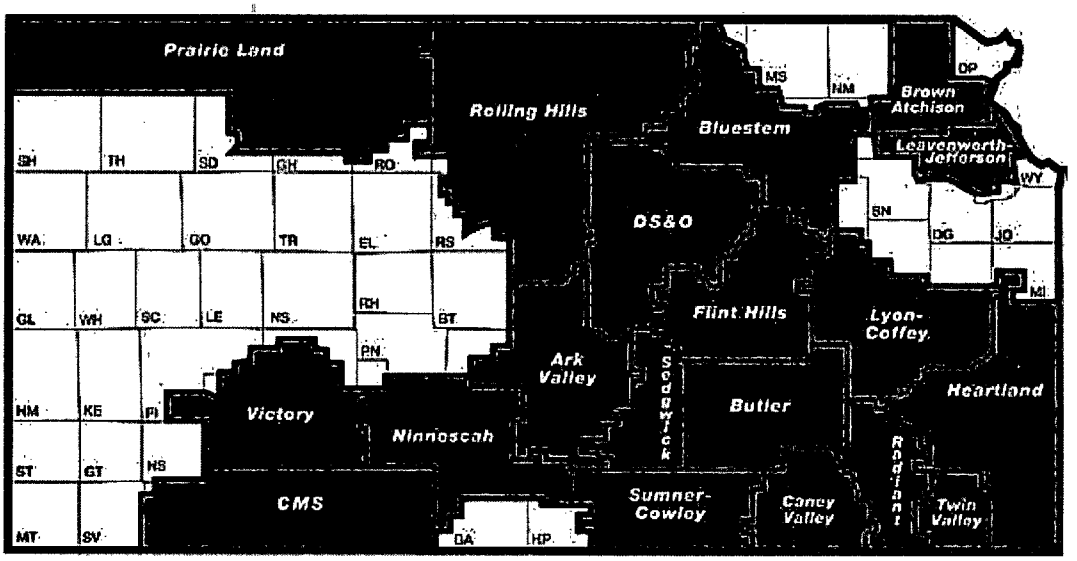
Ron Holsteen

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

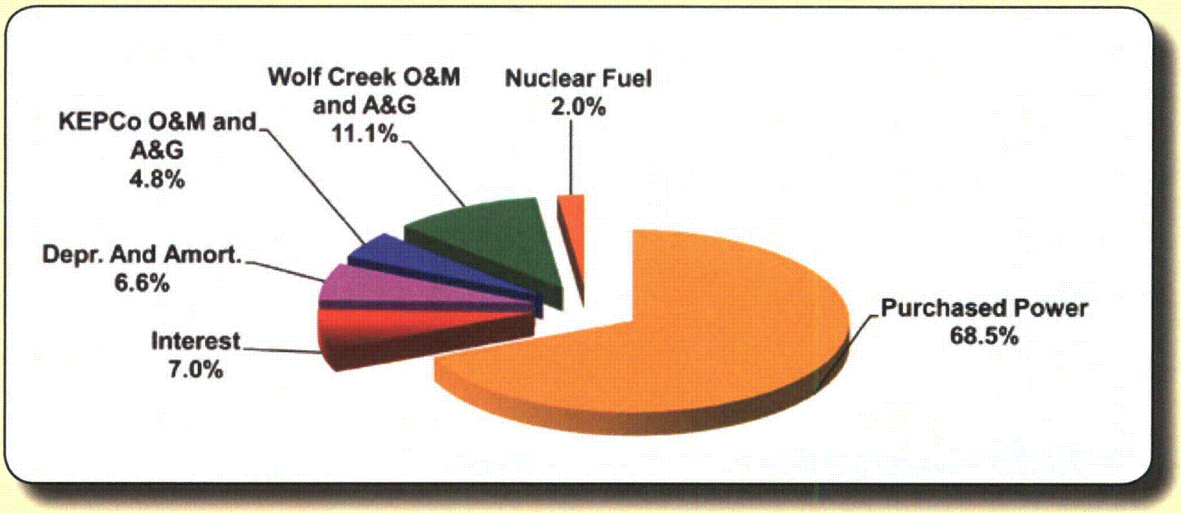
Terry Janson

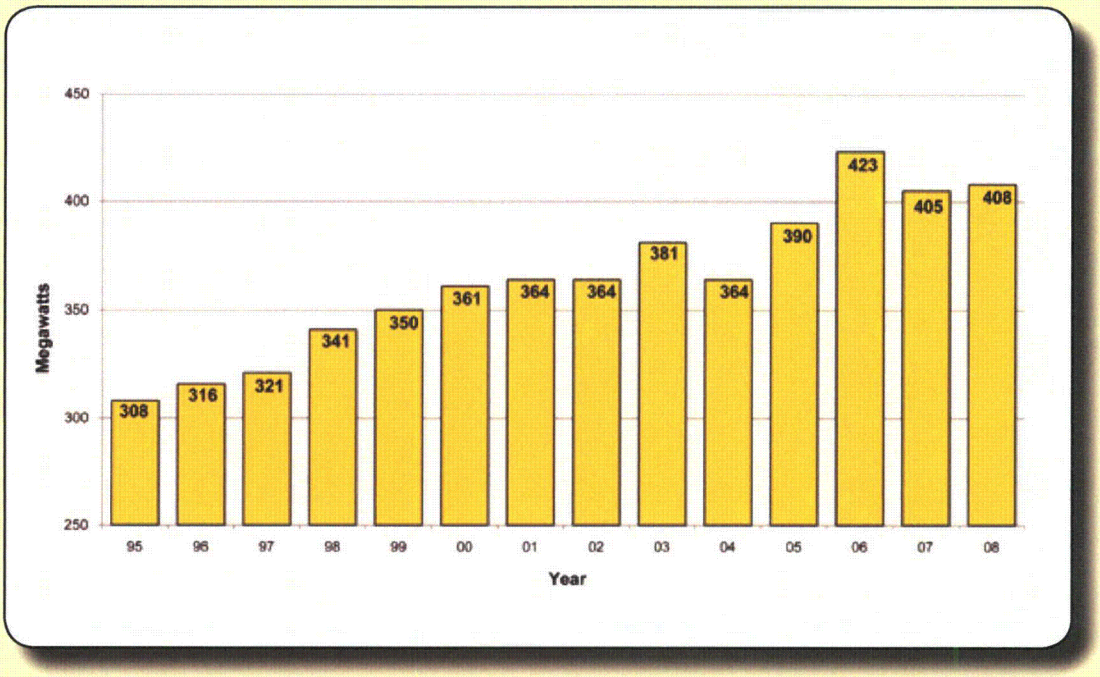
KEPCo Member Area Map



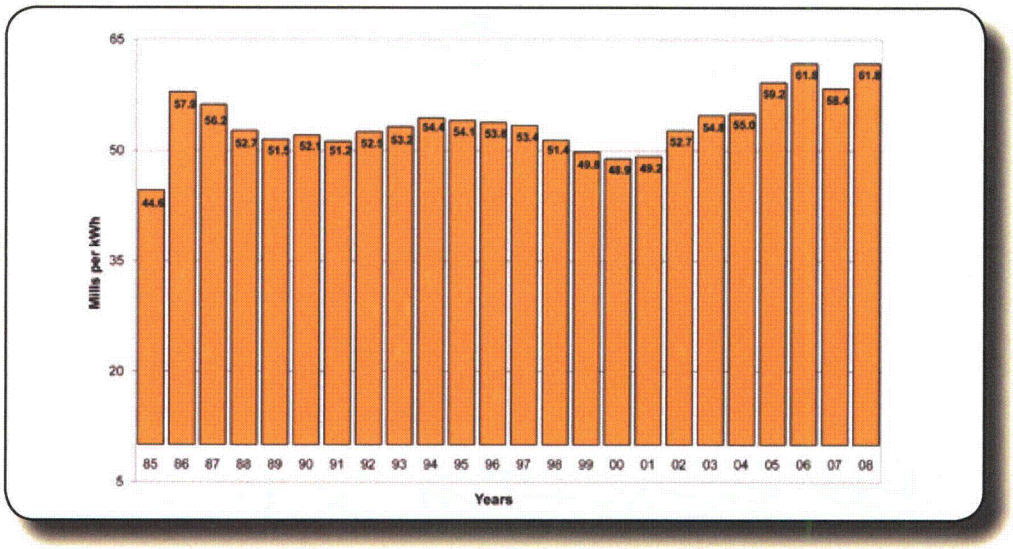
Operating Statistics

Operating Expenses



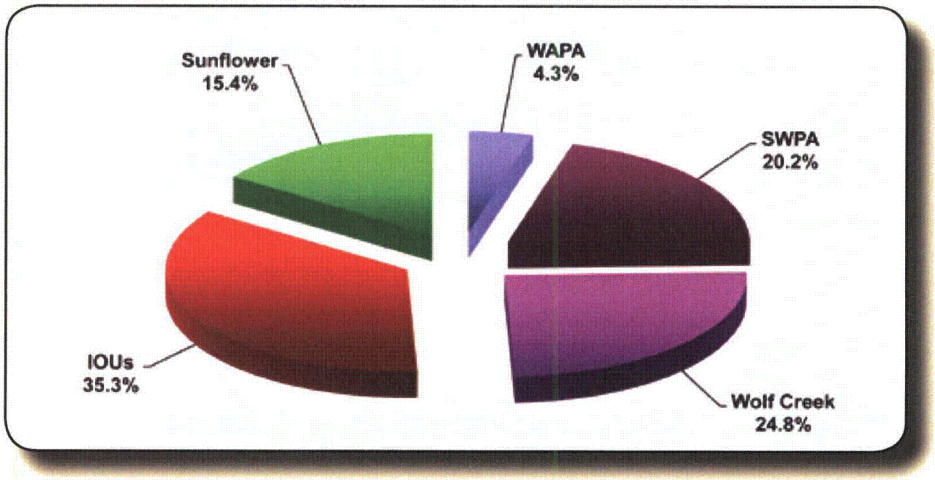


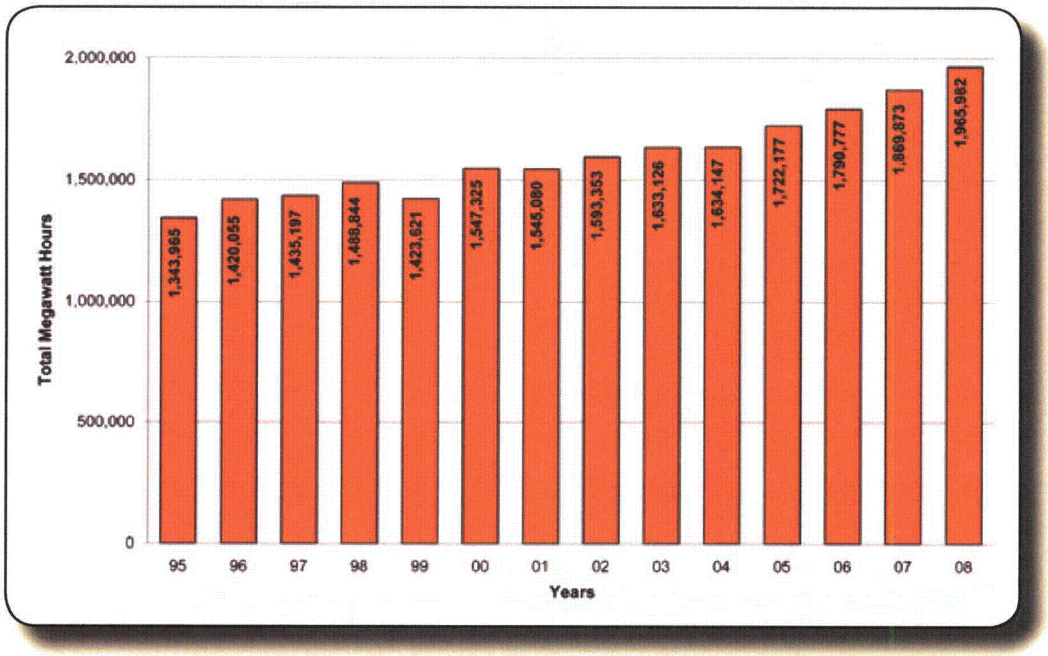
Peak Demand



Rates

Sources of Energy





Energy Sales

2008 Message

Continued from page 3

MW. KEPCo's load management program is critical in controlling peak demand. Implemented in 1990, KEPCo's load management program has saved its Membership millions of dollars since inception. This year was another successful year in that KEPCo was able to shed 30 MW of peak load, which saved its Members approximately $1.78 million.

In late December 2007, the state of Kansas experienced a devastating ice storm, affecting sixteen of KEPCo's nineteen Member Cooperatives and causing $300 million in damage. KSI Engineering (KSI), a wholly-owned subsidiary of KEPCo, assisted the affected cooperatives by assessing the damage to their facilities and preparing an engineering study that recommended appropriate repairs and/or replacements. As a result of difficulties in obtaining FEMA funding for the recommended permanent repairs, KSI's efforts transitioned to working with other stakeholders to educate FEMA on the extent of the damage, its impact on the electrical facilities, and developing a method to determine when electrical conductor is no longer suitable for continued service. KSI is confident these efforts will result in a national FEMA policy statement with regard to conductor repair/replacement as well as a revision to the FEMA project worksheets for the electric cooperatives affected by this disaster that is consistent with KSI's original repair/replacement recommendations.

The state of new base load generation in Kansas remains clouded. In mid-December, the Kansas Department of Health and Environment's decision to deny the issuance of an air permit to Sunflower Electric Power Corporation for the expansion of their Holcomb facility with two additional coal-fired generating units was upheld in an administrative appeal. Depending upon the outcome of potential judicial and legislative recourse, and the position the new administration in Washington, D.C. takes on coal-fired facilities, the future of new coal-fired generation in Kansas remains uncertain.

Before closing, the Board of Trustees deserves a special thank you for their vision and hard work during the past year. In addition, it has been a very challenging year for KEPCo staff who have done a remarkable job meeting the special project demands of 2008 while accomplishing the more familiar responsibilities necessary to run a utility.

KEPCo's long standing commitment to its Member Cooperatives and the communities they serve provides a solid foundation for meeting future challenges. The utility industry is in an era where energy decisions will be dictated more by environmental policy than by an integrated energy policy. Environmental regulation and the emphasis being placed upon renewable resources will shape the industry's generation and fuel choices in coming decades. Environmental regulation and subsequent standards will result in additional capital investment by the industry. KEPCo vows to work diligently to ensure that any climate change policy includes a well-considered strategy for electric-generating utilities and provides KEPCo as low a cost of carbon compliance possible.

Kenneth J. Maginley

Stephen E. Parr

Kansas Electric Power Cooperative, Inc.

Financial Statements

December 31, 2008 and 2007

BKD LLP
CPAs & Advisors

Two Leadership Square
211 N. Robinson, Suite 600
Oklahoma City, OK 73102-9421
405.842.7977 Fax 405.600.9799 www.bkd.com

Independent Accountants' Report

Board of Trustees
Kansas Electric Power Cooperative, Inc.
Topeka, Kansas

We have audited the accompanying consolidated balance sheets of Kansas Electric Power Cooperative, Inc. (KEPCo) as of December 31, 2008 and 2007, and the related consolidated statements of margin, patronage capital and cash flows for the years then ended. These financial statements are the responsibility of KEPCo's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America and the standards applicable to financial audits contained in *Government Auditing Standards*, issued by the Comptroller General of the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the 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.

As explained in *Note 3*, certain depreciation and amortization methods have been used in the preparation of the 2008 and 2007 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 consolidated financial statements referred to above present fairly, in all material respects, the financial position of Kansas Electric Power Cooperative, Inc., as of December 31, 2008 and 2007, and the results of its operations and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

As discussed in *Note 12*, in 2008 KEPCo changed its method for accounting for fair value measurement in accordance with Statement of Financial Accounting Standards No. 157.

As discussed in *Note 10*, KEPCo adopted Statement of Financial Accounting Standard No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans*, as of December 31, 2007.

In accordance with *Government Auditing Standards*, we also have issued our report dated April 8, 2009, on our consideration of KEPCo'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 8, 2009

experience BKD

Praxity MEMBER GLOBAL ALLIANCE OF INDEPENDENT FIRMS

Kansas Electric Power Cooperative, Inc.

Consolidated Balance Sheets

December 31, 2008 and 2007

Assets	2008	2007
Utility Plant		
In-service	$ 227,579,661	$ 224,863,485
Less allowance for depreciation	(125,525,931)	(122,771,314)
Net in-service	102,053,730	102,092,171
Construction work in progress	42,752,891	19,671,233
Nuclear fuel (less accumulated amortization of $13,923,600 and $15,025,746 for 2008 and 2007, respectively)	7,832,587	7,573,591
Total utility plant	152,639,208	129,336,995
Restricted Assets		
Investments in the National Rural Utilities Cooperative Finance Corporation	6,897,319	5,466,712
Bond fund reserve	4,321,172	4,348,709
Decommissioning fund	8,212,742	10,185,163
Investments in other associated organizations	176,430	164,072
Total restricted assets	19,607,663	20,164,656
Current Assets		
Cash and cash equivalents	634,108	6,132,774
Member accounts receivable	10,587,979	8,787,049
Materials and supplies inventory	3,245,861	3,123,051
Other assets and prepaid expenses	605,181	593,671
Total current assets	15,073,129	18,636,545
Other Long-term Assets		
Deferred charges		
Wolf Creek disallowed costs (less accumulated amortization of $12,635,061 and $11,877,898 for 2008 and 2007, respectively)	13,347,860	14,105,023
Wolf Creek deferred plants costs (less accumulated amortization of $21,909,437 and $18,779,517 for 2008 and 2007, respectively)	25,039,356	28,169,276
Wolf Creek decommissioning regulatory asset	7,354,075	4,247,845
Deferred incremental outage costs	3,352,986	1,092,847
Other deferred charges (less accumulated amortization of $7,305,536 and $6,826,077 for 2008 and 2007, respectively)	2,578,448	3,098,957
Unamortized debt issuance costs	619,634	734,861
Other investments	311,587	282,415
Total long-term assets	52,603,946	51,731,224
Total assets	$ 239,923,946	$ 219,869,420

Kansas Electric Power Cooperative, Inc.

Consolidated Balance Sheets

December 31, 2008 and 2007

Liabilities and Patronage Capital	2008	2007
Patronage Capital		
Memberships	$ 3,200	$ 3,200
Patronage capital	27,667,321	22,194,144
Accumulated other comprehensive loss	(5,684,416)	(3,120,448)
Total patronage capital	21,986,105	19,076,896
Long-term Debt	152,657,243	154,387,397
Other Long-term Liabilities		
Wolf Creek decommissioning liability	18,384,841	17,328,228
Wolf Creek pension and post retirement benefit plans	8,066,633	5,409,857
Wolf Creek deferred compensation	749,074	718,868
Arbitrage rebate long-term liability	811,354	660,863
Other deferred credits	16,277	16,643
Total other long-term liabilities	28,028,179	24,134,459
Current Liabilities		
Line of credit	13,178,203	–
Current maturities of long-term debt	13,159,154	11,950,139
Accounts payable	8,914,587	8,292,006
Payroll and payroll-related liabilities	313,735	304,110
Accrued property taxes	1,364,953	1,317,434
Accrued interest payable	321,787	406,979
Total current liabilities	37,252,419	22,270,668
Total patronage capital and liabilities	$ 239,923,946	$ 219,869,420

Kansas Electric Power Cooperative, Inc.

Consolidated Statements of Margin

December 31, 2008 and 2007

	2008	2007
Operating Revenues		
Sales of electric energy	$ 121,527,329	$ 109,228,388
Other	89,422	111,383
Total operating revenues	121,616,751	109,339,771
Operating Expenses		
Power purchased	80,023,770	69,728,597
Nuclear fuel	2,296,326	2,745,855
Plant operations	9,338,897	9,289,461
Plant maintenance	3,477,473	3,312,698
Administrative and general	5,413,479	5,367,620
Amortization of deferred charges	4,443,886	4,483,341
Depreciation and decommissioning	4,208,729	4,117,616
Total operating expenses	109,202,560	99,045,188
Net operating revenues	12,414,191	10,294,583
Interest and Other Deductions		
Interest on long-term debt	7,506,538	8,154,765
Amortization of debt issuance costs	115,227	120,542
Other deductions	71,044	115,567
Total interest and other deductions	7,692,809	8,390,874
Operating income	4,721,382	1,903,709
Other Income		
Interest income	634,867	640,660
Other income	116,928	152,288
Total other income	751,795	792,948
Net margin	$ 5,473,177	$ 2,696,657

Kansas Electric Power Cooperative, Inc.

Consolidated Statements of Patronage Capital

December 31, 2008 and 2007

	Comprehensive Income	Memberships	Patronage Capital	Accumulated Other Comprehensive Income (Loss)	Total
Balance, December 31, 2006		$ 3,200	$ 19,497,487	$ –	$ 19,500,687
Net margin	$ 2,696,657	–	2,696,657	–	2,696,657
Defined benefit pension plans					
Actuarial loss	–	–	–	(3,031,867)	(3,031,867)
Prior service cost	–	–	–	(22,769)	(22,769)
Transition obligation	–	–	–	(65,812)	(65,812)
Comprehensive income	$ 2,696,657				
Balance, December 31, 2007		3,200	22,194,144	(3,120,448)	19,076,896
Net margin	$ 5,473,177	–		–	–
Allocation of patronage capital		–	5,473,177	–	5,473,177
Defined benefit pension plans					
Net loss arising during year	(2,793,126)	–	–	(2,793,126)	(2,793,126)
Other	(38,764)	–	–	(38,764)	(38,764)
Less: amortization of prior service costs included in net periodic pension costs	267,922	–	–	267,922	267,922
Comprehensive income	$ 2,909,209				
Balance, December 31, 2008		$ 3,200	$ 27,667,321	$ (5,684,416)	$ 21,986,105

Kansas Electric Power Cooperative, Inc.

Consolidated Statements of Cash Flows

December 31, 2008 and 2007

	2008	2007
Operating Activities		
Net margin	$ 5,473,177	$ 2,696,657
Adjustments to reconcile net margin to net cash provided by operating activities		
Depreciation and amortization	3,794,729	3,683,888
Decommissioning	1,056,613	995,762
Amortization of nuclear fuel	1,811,603	2,104,442
Amortization of deferred charges	4,407,592	4,385,787
Amortization of deferred incremental outage costs	3,893,171	2,810,796
Amortization of debt issuance costs	115,227	120,542
Changes in		
Member accounts receivable	(1,800,955)	(765,716)
Materials and supplies	(122,810)	(139,576)
Other assets and prepaid expenses	(40,657)	25,638
Accounts payable	622,581	333,269
Payroll and payroll-related liabilities	9,625	19,449
Accrued property tax	47,519	(2,441)
Accrued interest payable	(85,192)	(169,584)
Restricted assets	27,537	(52,903)
Other long-term liabilities	273,139	545,694
Net cash provided by operating activities	19,482,899	16,591,704
Cash Flows From Investing Activities		
Additions to electric plant	(26,837,946)	(14,730,493)
Additions to nuclear fuel	(2,070,599)	(4,756,258)
Additions to deferred incremental outage costs	(6,153,310)	(368,294)
Investments in decommissioning fund assets	(1,133,809)	(998,246)
Other	(1,442,965)	(2,258,632)
Net cash used in investing activities	(37,638,629)	(23,111,923)
Cash Flows From Financing Activities		
Net borrowing (payment) under line of credit agreement	13,178,203	(3,521,028)
Principle payments on long-term debt	(11,950,139)	(11,162,496)
Proceeds from issuance of long-term debt	11,429,000	24,065,046
Net cash provided by financing activities	12,657,064	9,381,522
Net increase (decrease) in cash and cash equivalents	(5,498,666)	2,861,303
Cash and Cash Equivalents, Beginning of Year	6,132,774	3,271,471
Cash and Cash Equivalents, End of Year	$ 634,108	$ 6,132,774
Supplemental Cash Flows Information		
Cash paid during the year for interest	$ 7,622,812	$ 8,355,648

Kansas Electric Power Cooperative, Inc.

Notes to Consolidated Financial Statements

December 31, 2008 and 2007

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 approximately 120,000 electric meters 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 authority to establish KEPCo's electric rates under state law in Kansas. Rates are established to meet the times-interest-earned ratio and debt-service coverage set forth by the RUS. On December 21, 2007, KEPCo filed an application with the KCC requesting a rate increase of approximately $5.4 million and the reestablishment of a demand cost adjustment (DCA). The DCA will give KEPCo the ability to adjust rates annually to reflect changes in purchase power demand costs and to pass these costs along to its member cooperatives. On August 15, 2008, the KCC ordered an agreed-upon rate increase of approximately $5.2 million, including an annual DCA mechanism. The new rates became effective September 1, 2008. KEPCo's rates now include an energy cost adjustment (ECA) mechanism and an annual DCA mechanism, allowing KEPCo to pass along increases in certain energy and demand costs to its member cooperatives.

Principles of Consolidation

The consolidated financial statements include the amounts of KEPCo 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. Cost and additions to utility plant include contractual work, direct labor, materials and interest on funds used during construction. In 2008 and 2007, the amount of capitalized interest was $627,390 and $529,876, respectively. The cost of repairs and minor replacements are charged to operating expenses as appropriate. 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, 2008 and 2007, was 3.17% and 3.07%, 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, 2008 and 2007, approximately $8.2 million and $10.2 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 funds, which are carried at 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 ($31.1 million is KEPCo's share). The study assumes a 4.4% rate of inflation and 7% rate of return.

KEPCo adopted 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, 2008 and 2007, is as follows:

	2008	2007
Balance at January 1	$17,328,228	$16,332,466
Accretion	1,056,613	995,762
Balance at December 31	$18,384,841	$17,328,228

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 consisted primary of repurchase agreements, money market account and certificates of deposit.

The financial institution holding the Cooperative's cash accounts is participating in the FDIC's Transaction Account Guarantee Program. Under that program, through December 31, 2009, all noninterest-bearing transaction accounts are fully guaranteed by the FDIC for the entire amount in the account.

Effective October 3, 2008, the FDIC's insurance limits increased to $250,000. The increase in federally insured limits is currently set to expire December 31, 2009. At December 31, 2008, the Cooperative's interest-bearing cash accounts were covered by FDIC insurance.

The Cooperative's repurchase agreements have collateral pledged by a financial institution, which are securities that are backed by the full faith of the government. The Cooperative's money market account, which is held by a broker, was exposed to credit risk of approximately $58,000 at December 31, 2008.

Accounts Receivable

Accounts receivable are stated at the amount billed to members and customers. KEPCo 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.

	2008	2007
Cash surrender value of contracts	$ 5,276,957	$ 4,943,704
Borrowings against contracts	(5,276,957)	(4,943,704)
	$ –	$ –

Borrowings against contracts include a prepaid interest charge. KEPCo pays interest on these borrowings at a rate of 5.45% for the years ended December 31, 2008 and 2007.

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.

Uncertain Tax Positions

In accordance with Financial Accounting Standards Board (FASB) Staff Position No. FIN 48-3, the Cooperative has elected to defer the effective date of FASB Interpretation No. 48 (FIN 48), Accounting for Uncertainty in Income Taxes, until its fiscal year ending December 31, 2009. The Cooperative has continued to account for any uncertain tax positions in accordance with literature that was authoritative immediately prior to the effective date of FIN 48, such as FASB Statement No. 109, Accounting for Income Taxes, and FASB Statement No. 5, Accounting for Contingencies.

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 signifi-

cant change in the manner rates are set by regulators from a cost-based regulation to another form of regulation. KEPCo periodically reviews these criteria to ensure the continuing application of SFAS No. 71 is appropriate. Any changes that would require KEPCo to discontinue the application of SFAS No. 71 due to increased competition, regulatory changes or other events may significantly impact the valuation of KEPCo's investment in utility plant, its investment in Wolf Creek and necessitate the write-off of regulatory assets. At this time, the effect of competition and the amount of regulatory assets 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.

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:

	2008	2007
Deferred charges	$ 28,509,073	$ 32,072,707
Patronage capital	$ 28,509,073	$ 32,072,707
Net margin	$ (3,563,634)	$ (3,563,634)

Note 4: Wolf Creek Nuclear Operating Corporation

KEPCo owns 6% of Wolf Creek Nuclear Operating Corporation (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.

WCNOC is currently working on a capacity upgrade and received a 20-year operating license extension from the Nuclear Regulatory Commission in 2008.

Note 5: Investments in Associated Organizations

Investments in associated organizations are carried at cost. At December 31, 2008 and 2007, investments in as-

sociated organizations consisted of the following:

	2008	2007
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	81,690	40,737
Equity term certificates	4,213,659	2,824,005
	6,897,319	5,466,712
Other	176,430	164,072
	$ 7,073,749	$ 5,630,784

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

Wolf Creek 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 ($13.3 net of accumulated amortization as of December 31, 2008). 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, 2008 and 2007.

If the deferred plant costs were recovered using a method in accordance with accounting principles generally ac-

cepted 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 $6.2 million and $.04 million in 2008 and 2007, respectively. The current year amortization of the deferred incremental outage costs was $3.9 million and $2.8 million in 2008 and 2007, 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: Line of Credit

As of December 31, 2008, KEPCo has a $15,000,000 line of credit outstanding with the CFC. This line of credit expires in March of 2011. There were outstanding borrowings of $13,178,203 at December 31, 2008. There were no funds borrowed against the line of credit at December 31, 2007. The line of credit requires the Cooperative to pay down the balance to zero annually. Interest varies and was 5.00% at December 31, 2008 and 6.40% at December 31, 2007.

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:

	2008	2007
Mortgage notes payable to the FFB at fixed rates varying from 3.617% to 9.206%, payable in quarterly installments through 2020	$ 72,149,927	$ 78,787,354
Mortgage notes payable to the Grantor Trust Series 1997 at a rate of 7:522%, payable semiannually, principal payments commencing in 1999 and continuing annually through 2017	38,040,000	40,840,000
Floating/fixed rate pollution control revenue bonds, City of Burlington, Kansas, Pooled Series 1985C, variable interest rate (ranging from 0.93% to 1.60% at December 31, 2008) payable annually through 2017	22,500,000	24,700,000
Mortgage notes payable and equity certificate loans to the National Rural Utilities Cooperative Finance Corporation at fixed rates of 5.40% to 6.10%, payable quarterly through 2017. Currently, KEPCo has approximately $58.0 million of funds available to borrow, which mature in 2012	33,126,470	22,010,182
	165,816,397	166,337,536
Less current maturities	13,159,154	11,950,139
	$ 152,657,243	$ 154,387,397

Aggregate maturities of long-term debt for the next five years and thereafter are as follows:

2009	$ 13,159,154
2010	14,091,957
2011	15,188,130
2012	45,864,351
2013	17,388,881
Thereafter	60,123,924
	$ 165,816,397

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, 2008 and 2007.

In 1997, KEPCo refinanced its mortgage notes payable to the 1988 CFC Grantor Trust through the establishment of a new CFC Grantor Trust Series 1997 (the Series 1997 Trust) by CFC. This refinancing reduced the guaranteed interest rate payable on the mortgage notes to a fixed rate of 7.522% through the use of an interest rate swap that was assigned by KEPCo to the Series 1997 Trust. The mortgage notes payable are prepayable at any time with no prepayment penalties. However, any termination costs relating to the termination of the assigned interest rate swaps is KEPCo's responsibility. At December 31, 2008, the termination obligation associated with the assigned swap agreement to early retire the mortgage notes payable is approximately $17.6 million. This fair value estimate is based on information available at December 31, 2008, 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 employer members. KEPCo's expense under this program was $0.3 million and $0.3 million for the years ended December 31, 2008 and 2007, respectively.

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, 2008 and 2007.

WCNOC Pension and Postretirement Plans

KEPCo has an obligation to the WCNOC retirement, supplemental retirement and postretirement medical 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 31 for its retirement plan, its supplemental retirement plan and postretirement plan (collectively "the Plans"). Information about KEPCo's 6% of the Plans' funded status follows:

	Pension Benefits		Postretirement Benefits	
	2008	2007	2008	2007
Benefit obligation	$ (12,706,873)	$ (11,469,649)	$ (1,129,978)	$ (1,097,210)
Fair value of plan assets	5,770,218	7,157,002	–	–
	$ (6,936,655)	$ (4,312,647)	$ (1,129,978)	$ (1,097,210)

Amounts recognized in the consolidated balance sheets:

	2008	2007
Other long-term liabilities		
Wolf Creek pension and postretirement benefit plans	$ 8,066,633	$ 5,409,857

Amounts recognized in accumulated other comprehensive income (loss) not yet recognized as components of net periodic benefit cost consist of:

	Pension Benefits		Postretirement Benefits	
	2008	2007	2008	2007
Net loss	$ (5,208,752)	$ (2,692,708)	$ (409,877)	$ (339,159)
Prior service cost	(15,188)	(22,769)	–	–
Transition obligation	(21,168)	(29,030)	(29,731)	(36,782)
	$ (5,245,108)	$ (2,744,507)	$ (439,608)	$ (375,941)

Information for the pension plan with an accumulated benefit obligation in excess of plan assets:

	Pension Benefits	
	2008	2007
Projected benefit obligation	$ 12,706,873	$ 11,469,649
Accumulated benefit	$ 9,854,875	$ 8,719,461
Fair value of plan assets	$ 5,770,218	$ 7,157,002

Other significant balances and costs are:

	Pension Benefits		Postretirement Benefits	
	2008	2007	2008	2007
Employer contributions	$ 843,543	$ 717,218	$ 105,411	$ 65,085
Benefits paid	$ 251,427	$ 230,966	$ 150,853	$ 65,085
Benefits cost	$ 791,759	$ 955,522	$ 128,775	$ 150,168

The estimated net loss, prior service cost and transition obligation for the defined benefit pension plans that will be amortized from accumulated other comprehensive income (loss) into net periodic benefit cost over the next fiscal year are approximately $305,000, $6,000 and $7,000, respectively. The estimated net loss and transition obligation for the defined benefit postretirement plan that will be amortized from accumulated other comprehensive income (loss) into net periodic benefit cost over the next fiscal year are approximately $30,000 and $7,000, respectively.

Significant assumptions used to determine benefit obligations include:

	Pension Benefits		Postretirement Benefits	
	2008	2007	2008	2007
Discount rate	6.15%	6.15%	6.05%	6.05%
Annual salary increase rate	4.00%	4.00%	N/A	N/A
Expected return on plan assets	8.25%	8.25%	N/A	N/A
Assumed health care cost trend rate	N/A	N/A	8.0% decreasing 0.5% per year to 5.0%	8.0% decreasing 0.5% per year to 5.0%

WCNOC uses an interest yield curve to make judgements pursuant to EITF Topic No. D-36, Selection of Discount Rates Used for Measuring Defined Benefit Pension Obligations and Obligations of Postretirement Benefit Plans Other Than Pensions. The yield curve is constructed based on yields on over 500 high-quality, noncallable cor-

porate bonds with maturities between 0 and 30 years. A theoretical spot rate curve constructed from this yield curve is then used to discount the annual benefit cash flows of WCNOC's pension plan and develop a single-point discount rate matching the plan's payout structure.

The expected long-term rate of return on plan assets is based on historical and projected rates of return for current and planned assets classes in the pension plan's investment portfolio. Assumed and 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 allocation 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 from plan assets.

In selecting the discount rate, fixed income security yield rates for corporate high-grade bond yields were considered.

The defined benefit pension plan assets are invested in insurance contracts, corporate bonds, equity securities, United States government securities and short-term investments.

The asset allocation for the defined benefit pension plan at the end of 2008 and 2007, and the target allocation for 2009 by asset category are as follows:

	Target Allocation for 2009	Pension Plan Assets 2008	2007
Asset category			
Equity securities	65%	58%	67%
Debt securities	25%	39%	28%
Real estate	5%	1%	0%
Other	5%	2%	5%
	100%	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 estimates cash contributions of approximately $700,000 will be made to the Plans in 2009.

Estimated future benefit payments for the Plans, which reflect expected future services, are as follows:

	Pension Benefits	Other Benefits
2009	$ 305,700	$ 78,120
2010	329,400	78,720
2011	360,180	78,600
2012	397,380	78,600
2013	443,880	82,260
2014-2017	3,194,340	451,020
	$ 5,030,880	$ 847,320

At December 31, 2007, KEPCo adopted Statement of Financial Accounting Standard No. 158, Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans (FAS 158). FAS 158 required KEPCo to recognize a liability for the unfunded status of the Plans and adjust accumulated other comprehensive income for the transition obligation, prior service cost and net loss that had not yet been recognized as components of net periodic benefit cost at that date. The following table illustrates the incremental effect of applying FAS 158 on individual line items in the balance sheet at December 31, 2007.

	Before	Adjustment	After
Accumulated other comprehensive income (loss)	$ -	$ (3,120,448)	$ (3,120,448)
Total patronage capital	$ 22,197,344	$ (3,120,448)	$ 19,076,896
Wolf Creek pension and postretirement benefit plans long-term liability	$ 2,289,409	$ 3,120,448	$ 5,409,857
Total other long-term liabilities	$ 21,014,011	$ 3,120,448	$ 24,134,459

Note 11: Commitments and Contingencies

Current Economic Environment

The Cooperative considers the current economic conditions when planning for future power supply and liquidity needs. The current instability in the financial markets may have an impact on the Cooperative's members, which may impact the Cooperative's volume of future sales which could have an adverse impact on the Cooperative's future operating results. The current economic climate may also affect the Cooperative's ability to obtain financing.

Given the volatility of the current economic conditions, the values of assets and liabilities recorded in the financial statements could change rapidly, resulting in material future adjustments that could negatively impact the Cooperative's ability to meet debt covenants or maintain sufficient liquidity. Being a regulated entity, the Cooperative expects to be able to recover any economic losses through future rate proceedings.

Litigation

The Cooperative is subject to claims and lawsuits that arise primarily in the ordinary course of business. It is the opinion of management that the disposition or ultimate resolution of such claims and lawsuits will not have an adverse effect on the consolidated financial position, results of operations and cash flows of the Cooperative.

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 $12.5 billion. This limit of liability consists of the maximum available commercial insurance of $300 million, and the remaining $12.2 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 $117.5 million ($7.1 million–KEPCo's share) at any commercial reactor in the country, payable at no more than $17.5 million ($1.1 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 August 2013. 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 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 $1.4 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 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 million in covered damages and causes Wolf Creek to be prematurely decommissioned.

Nuclear Fuel Commitments

At December 31, 2008, KEPCo's share of WCNOC's nuclear fuel commitments was approximately $7.3 million for uranium concentrates expiring in 2018, $1.1 million for conversion expiring in 2018, $18.8 million for enrichment expiring at various times through 2025, and $6.5 million for fabrication through 2025.

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 contract with Westar Energy, Inc., through May 2010 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.

Iatan 2 Purchase Commitment

Effective June 2006, KEPCo entered into an agreement, subject to RUS approval, to purchase a 3.53% ownership in a coal fired generation facility. KEPCo's estimated costs for the project were $75 million at December 31, 2008. To date, the Cooperative has paid approximately $40 million under the agreement. Financing is currently being provided by CFC.

Note 12: Disclosures About Fair Value of Assets and Liabilities

Effective January 1, 2008, KEPCo adopted Statement of Financial Accounting Standards No. 157, Fair Value Measurements (FAS 157). FAS 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. FAS 157 has been applied prospectively as of the beginning of the year.

FAS 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. FAS 157 also establishes a fair value hierarchy which requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. The standard describes three levels of inputs that may be used to measure fair value:

Level 1 Quoted prices in active markets for identical assets or liabilities

Level 2 Observable inputs other than Level 1 prices, such as quoted prices for similar assets or liabilities; quoted prices in markets that are not active; or other inputs that are observable or can be corroborated by observable market data for substantially the full term of the assets or liabilities

Level 3 Unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets or liabilities

Following is a description of the valuation methodologies used for assets and liabilities measured at fair value on a recurring basis and recognized in the accompanying consolidated balance sheets, as well as the general classification of such assets and liabilities pursuant to the valuation hierarchy.

Decommissioning Fund

The decommissioning fund consists of various mutual funds where fair value is determined by quoted market prices in an active market and as such are classified within Level 1 of the valuation hierarchy.

The following table presents the fair value measurements of assets and liabilities recognized in the accompanying consolidated balance sheets measured at fair value on a recurring basis and the level within the FAS 157 fair value hierarchy in which the fair value measurements fall at December 31, 2008:

		Fair Value Measurements Using		
	Fair Value	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Decommissioning	$ 8,212,742	$ 8,212,742	$ –	$ –

The following methods were used to estimate the fair value of all other financial instruments recognized in the accompanying consolidated balance sheets at amounts other than fair value.

Cash and Cash Equivalents

The carrying amount approximates fair value.

Investments in CFC and Other Associated Organizations

KEPCo considers CFC and other associated organizations certificates to be a condition of borrowing and patronage capital certificates to be directly related to borrowing. As such, KEPCo management believes the fair value of these assets is not determinable and they are reflected at their carrying amount.

Bond Fund Reserve

The bond fund reserve consists of various held-to maturity securities where the fair value is primarily based on quoted market prices.

Line of Credit and Long-Term Debt

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 all fixed-rate debt is based on the sum of the estimated value of each issue, taking into consideration the current rate offered to KEPCo for debt of similar remaining maturities.

The following table presents estimated fair values of KEPCo's financial instruments at December 31, 2008 and 2007:

	December 31, 2008		December 31, 2007	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Financial assets				
Cash and cash equivalents	$ 634,108	$ 634,108	$ 6,132,774	$ 6,132,774
Bond fund reserve	$ 4,321,172	$ 4,578,569	$ 4,348,709	$ 4,531,910
Decommissioning fund	$ 8,212,742	$ 8,212,742	$ 10,185,163	$ 10,185,163
Financial liabilities				
Line of credit	$ 13,178,203	$ 13,178,203	$ –	$ –
Long-term debt	$ 165,816,397	$ 174,124,971	$ 166,337,536	$ 168,908,545

Note 13: Patronage Capital

In accordance with KEPCo's bylaws, 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 2008 and 2007.

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