- **Removal costs:** This represents amounts collected, but unspent, for costs to dispose of utility plant assets that do not represent legal retirement obligations. The liability will be discharged as removal costs are incurred.
- **Other regulatory liabilities:** This includes various regulatory liabilities that individually are relatively small in relation to the total regulatory liability balance. Other regulatory liabilities will be credited over various periods, most of which range from one to five years.

Cash and Cash Equivalents

We consider investments that are highly liquid and that have maturities of three months or less when purchased to be cash equivalents.

Inventories and Supplies

We state inventories and supplies at average cost.

Property, Plant and Equipment

We record the value of property, plant and equipment at cost. For utility plant, cost includes contracted services, direct labor and materials, indirect charges for engineering and supervision, and an allowance for funds used during construction (AFUDC). AFUDC represents the cost of 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,	2007	2006	2005
		(In Thousands)	
Borrowed funds	$ 13,090	$ 4,053	$ 2,655
Equity funds	4,346	—	—
Total	$ 17,436	$ 4,053	$ 2,655
Average AFUDC Rates	6.6%	5.3%	4.2%

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

Depreciation

We depreciate utility plant using a straight-line method at rates based on the estimated remaining useful lives of the assets. These rates are based on an average annual composite basis using group rates that approximated 2.7% in both 2007 and 2006 and 2.5% in 2005.

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

	Years
Fossil fuel generating facilities	15 to 75
Nuclear fuel generating facility	40 to 60
Transmission facilities	45 to 65
Distribution facilities	19 to 65
Other	5 to 35

In the 2005 KCC Order, the KCC approved a change in our depreciation rates. This change increased our annual depreciation expense by approximately $8.8 million.

Nuclear Fuel

We record as property, plant and equipment our share of the cost of nuclear fuel used in the process of refinement, conversion, enrichment and fabrication. We reflect this at original cost and amortize such amounts to fuel expense based on the quantity of heat consumed during the generation of electricity, as measured in millions of British thermal units (MMBtu). The accumulated amortization of nuclear fuel in the reactor was $36.4 million as of December 31, 2007, and $19.6 million as of December 31, 2006. Spent nuclear fuel charged to fuel and purchased power expense was $21.7 million in 2007, $18.8 million in 2006 and $18.0 million in 2005.

Cash Surrender Value of Life Insurance

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

As of December 31,	2007	2006
	(In Thousands)	
Cash surrender value of policies	$1,117,828	$1,053,231
Borrowings against policies	(1,031,155)	(971,892)
Corporate-owned life insurance, net	$ 86,673	$ 81,339

We record income for increases in cash surrender value and death proceeds. We offset against policy income the interest expense that we incur on policy loans. Income recognized from death proceeds is highly variable from period to period. Death benefits approximated $2.4 million in 2007, $18.9 million in 2006 and $9.5 million in 2005.

Revenue Recognition — Energy Sales

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

The accuracy of the unbilled revenue estimate is affected by factors that include fluctuations in energy demands, weather, line losses and changes in the composition of customer classes. We had estimated unbilled revenue of $43.7 million as of December 31, 2007, and $38.4 million as of December 31, 2006.

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 are recorded 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. Prices used to value these transactions reflect our best estimate of the fair value of our contracts. Results actually achieved from these activities could vary materially from intended results and could affect our consolidated financial results.

Income Taxes

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

As of January 1, 2007, we account for uncertainty in income taxes in accordance with Financial Accounting Standards Board (FASB) Interpretation No. (FIN) 48. The application of income tax law is inherently complex. Laws and regulations in this area are voluminous and are often ambiguous. As such, we are required to make many subjective assumptions and judgments regarding our income tax exposures. Interpretations of and guidance surrounding income tax laws and regulations change over time. As such, changes in our subjective assumptions and judgments can materially affect amounts recognized in the consolidated financial statements. See Note 11 to the Notes to Consolidated Financial Statements, "Income 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, these amounts are not reflected in the consolidated statements of income.

Dilutive Shares

We report basic earnings per share applicable to equivalent common stock based on the weighted average number of common shares outstanding and shares issuable in connection with vested restricted share units (RSU) during the period reported. Diluted earnings per share include the effects of potential issuances of common shares resulting from the assumed vesting of all outstanding RSUs, the exercise of all outstanding stock options issued pursuant to the terms of our stock-based compensation plans and the physical settlement of a forward sale agreement. The dilutive effect of shares issuable under our stock-based compensation plans and forward sale agreement is computed using the treasury stock method.

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

Year Ended December 31,	2007	2006	2005
DENOMINATOR FOR BASIC AND DILUTED EARNINGS PER SHARE:			
Denominator for basic earnings per share — weighted average equivalent shares	90,675,511	87,509,800	86,855,485
Effect of dilutive securities:			
Employee stock options	952	788	1,750
Restricted share units	517,694	589,352	552,423
Forward sale agreement	66,686	—	—
Denominator for diluted earnings per share — weighted average equivalent shares	91,260,843	88,099,940	87,409,658
Potentially dilutive shares not included in the denominator because they are antidilutive	74,890	158,080	214,340

Supplemental Cash Flow Information

Year Ended December 31,	2007	2006	2005
		(In Thousands)	
CASH PAID FOR:			
Interest on financing activities, net of amount capitalized	$ 84,291	$ 88,872	$ 87,634
Income taxes	74,970	72,407	772
NON-CASH INVESTING TRANSATIONS:			
Jeffrey Energy Center 8% leasehold interest	118,538	—	—
Other property, plant and equipment additions	100,039	29,134	10,800
NON-CASH FINANCING TRANSACTIONS:			
Issuance of common stock for reinvested dividends and RSUs	10,553	10,094	11,728
Capital lease for Jeffrey Energy Center 8% leasehold interest	118,538	—	—
Other assets acquired through capital leases	3,228	4,491	3,716

New Accounting Pronouncements

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 shall report unrealized gains and losses on items for which fair value option has been elected in earnings at each subsequent reporting date. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007, 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. We adopted the guidance effective January 1, 2008. The adoption of SFAS No. 157 did not have a material impact on our consolidated financial statements.

3. RATE MATTERS AND REGULATION

Changes in Rates

On December 28, 2005, the KCC issued an order (2005 KCC Order) authorizing changes in our rates, which we began billing in the first quarter of 2006, and approving various other changes in our rate structures. In April 2006, interveners to the rate review filed appeals with the Kansas Court of Appeals challenging various aspects of the 2005 KCC Order. On July 7, 2006, the Kansas Court of Appeals reversed and remanded for further consideration by the KCC three elements of the 2005 KCC Order (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 transmission delivery charge, in the circumstances of this case, violated the Kansas statutes that authorize a transmission delivery charge, (ii) the KCC's approval of recovery of terminal net salvage, adjusted for inflation, in our depreciation rates was not supported by substantial competent evidence, and (iii) the KCC's reversal of its prior rate treatment of the La Cygne Generating Station (La Cygne) unit 2 sale-leaseback transaction was not sufficiently justified and was thus unreasonable, arbitrary and capricious.

On February 8, 2007, the KCC issued an order (February 2007 KCC Order) in response to the July 2006 Court 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 transmission delivery charge 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

Request for Change in Transmission Rates

On May 2, 2005, we filed applications with the Federal Energy Regulatory Commission (FERC) that proposed a formula transmission rate providing for annual adjustments to our transmission 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. The proposed FERC transmission rates became effective, subject to refund, December 1, 2005. On November 7, 2006, FERC issued an order reflecting a unanimous settlement reached by the parties to the proceeding. The settlement modified the rates we proposed and required us to refund approximately $3.4 million, which included the amount we collected in the interim rates since December 2005 and interest on that amount.

On December 28, 2007, we filed applications with FERC that proposed changes to our formula transmission rate, which provides for annual adjustments to our transmission tariff. While the formula already allows recovery of the prior year's actual costs, the changes, if accepted by FERC, will allow us to include in our formula rate our anticipated transmission capital expenditures for the current year. We have requested the changes take effect on June 1, 2008. In addition, we made a simultaneous filing requesting authority for incentives related to new transmission investments as permitted by FERC.

On November 6, 2007, we filed applications with FERC that proposed the use of a consolidated capital structure in our formula transmission rate. On December 19, 2007, FERC issued an order accepting this change. On January 28, 2008, we filed applications with FERC requesting that this change be effective June 1, 2007. Accordingly, we have recorded a $3.7 million refund obligation, which includes the amount we have collected since June 1, 2007, and interest on that amount.

Rate Review Request

We will file a request for a rate review with the KCC during 2008, based on a test year consisting of the 12 months ended December 31, 2007.

4. ACCOUNTS RECEIVABLE SALES PROGRAM

We terminated our accounts receivable sales program in March 2006. The amounts sold to the bank and commercial paper conduit were $65.0 million as of December 31, 2005. We recorded this activity on the consolidated statements of cash flows for the year ended December 31, 2005, in the "accounts receivable, net" line of cash flows from operating activities.

5. FINANCIAL INSTRUMENTS, ENERGY MARKETING AND RISK MANAGEMENT

Values of Financial Instruments

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

Cash and cash equivalents, short-term borrowings and variable-rate debt are carried at cost, which approximates fair value. The nuclear decommissioning trust is recorded at fair value, which is estimated based on the quoted market prices as of December 31, 2007 and 2006. See Note 6, "Financial Investments and Trading Securities," for additional information about our nuclear decommissioning trust. The fair value of fixed-rate debt is estimated based on quoted market prices for the same or similar issues or on the current rates offered for instruments of the same remaining maturities and redemption provisions.

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

We base estimates of fair value on information available as of December 31, 2007 and 2006. These fair value estimates have not been comprehensively revalued for the purpose of these financial statements since that date and current estimates of fair value may differ from the amounts below. The carrying values and estimated fair values of our financial instruments are as shown in the table below.

	Carrying Value		Fair Value	
As of December 31,	2007[(a)]	2006	2007[(a)]	2006
	(In Thousands)			
Fixed-rate debt, net of current maturities.......	$1,619,381	$1,294,405	$1,586,407	$1,277,497

[(a)] *This amount does not include an equipment financing loan of $1.8 million.*

Derivative Instruments

We are exposed to market risks from changes in commodity prices and interest rates that could affect our consolidated results of operations and financial condition. We manage our exposure to these market risks through our regular operating and financing activities and, when deemed appropriate, economically hedge a portion of these risks through the use of derivative financial instruments. We use the term economic hedge to mean a strategy designed to manage risks of volatility in prices or rate movements on some assets, liabilities or anticipated transactions by creating a relationship in which gains or losses on derivative instruments are expected to counterbalance the losses or gains on the assets, liabilities or anticipated transactions exposed to such market risks. We use derivative instruments as risk management tools consistent with our business plans and prudent business practices and for energy marketing purposes.

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

Energy Marketing Activities

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

Within the trading portfolio, we take certain positions to economically hedge a portion of physical sale or purchase contracts and we take certain positions to take advantage of market trends and conditions. With the exception of a fuel supply contract and a capacity sale contract, which are recorded 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 selected market opportunities. We refer to these transactions as energy marketing activities.

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

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

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

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

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

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

6. FINANCIAL INVESTMENTS AND TRADING SECURITIES

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

Trading Securities

We have investments in trust assets securing certain executive benefits that are classified as trading securities. We include any unrealized gains or losses on these securities in investment earnings on our consolidated statements of income. There were an unrealized gain of $2.8 million as of December 31, 2007, an unrealized gain of $1.7 million as of December 31, 2006, and an unrealized loss of $0.3 million as of December 31, 2005.

Available-for-Sale Securities

We hold investments in debt and equity securities in a trust fund for the purpose of funding the decommissioning of Wolf Creek. We have classified these investments in debt and equity securities as available-for-sale and have recorded all such investments at their fair market value as of December 31, 2007 and 2006. Investments by the nuclear decommissioning trust fund are allocated 70% to equity securities, 27% to fixed-income securities and 3% to cash and cash equivalents. Fixed-income investments are limited to U.S. government or agency securities, municipal bonds, or corporate securities. Using the specific identification method to determine cost, the gross realized gains on those sales were $5.7 million in 2007, $7.5 million in 2006 and $3.2 million in 2005. We reflect net realized and unrealized gains and losses in regulatory liabilities on our consolidated balance sheets. This reporting is consistent with the method we use to account for the decommissioning costs recovered in rates. Gains or losses on assets in the trust fund could result in lower or higher funding requirements for decommissioning costs, which we believe would be reflected in electric rates paid by our customers.

The following table presents the costs and fair values of investments in debt and equity securities in the nuclear decommissioning trust fund as of December 31, 2007 and 2006. Changes in the fair value of the trust fund are recorded as an increase or decrease to the regulatory liability recorded in connection with the decommissioning of Wolf Creek.

Security Type	Cost	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
		(In Thousands)		
2007:				
Debt securities	$ 33,705	$ 450	$ (528)	$ 33,627
Equity securities	69,505	19,031	(2,971)	85,565
Cash equivalents	3,106	—	—	3,106
Total	$106,316	$ 19,481	$(3,499)	$ 122,298
2006:				
Debt securities	$ 36,947	$ 349	$ (168)	$ 37,128
Equity securities	57,202	13,754	(1,288)	69,668
Cash equivalents	4,339	—	—	4,339
Total	$ 98,488	$ 14,103	$(1,456)	$ 111,135

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

As of December 31, 2007	Cost	Fair Value
	(In Thousands)	
Less than 5 years	$ 5,820	$ 5,881
5 years to 10 years	5,035	5,092
Due after 10 years	11,870	12,020
Sub-total	22,725	22,993
Fixed Income Fund	10,980	10,634
Total	$ 33,705	$ 33,627

The following table presents the fair value and the gross unrealized losses of the available-for-sale securities held in the nuclear decommissioning trust fund that were not deemed to be other-than-temporarily impaired, aggregated by investment category and the length of time that individual securities have been in a continuous unrealized loss position, at December 31, 2007.

	Less than 12 Months		12 Months or Greater		Total	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
			(In Thousands)			
Debt securities	$13,781	$ (488)	$ 849	$ (40)	$14,630	$ (528)
Equity securities	11,758	(2,488)	565	(483)	12,323	(2,971)
Total	$25,539	$(2,976)	$1,414	$(523)	$26,953	$(3,499)

7. PROPERTY, PLANT AND EQUIPMENT

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

As of December 31,	2007	2006
	(In Thousands)	
Electric plant in service	$6,452,522	$6,066,954
Electric plant acquisition adjustment	802,318	802,318
Accumulated depreciation	(3,142,550)	(2,979,159)
	4,112,290	3,890,113
Construction work in progress	630,782	142,351
Nuclear fuel, net	60,566	39,109
Net utility plant	4,803,638	4,071,573
Non-utility plant in service	34	34
Net property, plant and equipment	$4,803,672	$4,071,607

We recorded depreciation expense on utility property, plant and equipment of $170.0 million in 2007, $159.9 million in 2006 and $130.1 million in 2005.

8. JOINT OWNERSHIP OF UTILITY PLANTS

Under joint ownership agreements with other utilities, we have undivided ownership interests in four electric generating stations. Energy generated and operating expenses are divided on the same basis as ownership with each owner reflecting its respective costs in its statements of income. Information relative to our ownership interest in these facilities as of December 31, 2007, is shown in the table below.

	Our Ownership as of December 31, 2007					
	In-Service Dates	Investment	Accumulated Depreciation	Construction Work in Progress	Net MW	Ownership Percent
			(Dollars in Thousands)			
La Cygne unit 1[(a)]	June 1973	$ 269,618	$ 129,068	$ 1,825	368.0	50
Jeffrey unit 1[(b)]	July 1978	326,539	176,606	75,539	672.0	92
Jeffrey unit 2[(b)]	May 1980	318,898	156,603	42,183	672.0	92
Jeffrey unit 3[(b)]	May 1983	471,736	220,432	63,678	672.0	92
Jeffrey wind 1[(b)]	May 1999	966	392	—	0.7	92
Jeffrey wind 2[(b)]	May 1999	966	392	—	0.7	92
Wolf Creek[(c)]	Sept. 1985	1,417,485	647,489	26,517	545.0	47
State Line[(d)]	June 2001	106,994	28,113	149	204.0	40
Total		$2,913,202	$1,359,095	$209,891	3,134.4	

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

Amounts and capacity presented above represent our share. We include in operating expenses on our consolidated statements of income our share of operating expenses of the above plants, as well as such expenses for a 50% undivided interest in La Cygne unit 2 (representing 341 megawatts of capacity) sold and leased back to KGE in 1987. Our share of other transactions associated with the plants is included in the appropriate classification on our consolidated financial statements.

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.

9. SHORT-TERM DEBT

A syndicate of banks provides us a revolving credit facility on a committed basis totaling $500.0 million. Effective March 16, 2007, $480.0 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. So long as there is no default or event of default under the revolving credit facility, we may elect to extend the term of the credit facility for one year. This one year extension can be requested twice during the term of the facility, subject to lender participation. The facility allows us to borrow up to an aggregate amount of $500.0 million, including letters of credit up to a maximum aggregate amount of $150.0 million. As of December 31, 2007, we had borrowings of $180.0 million and $45.5 million of letters of credit outstanding under this facility. On January 11, 2008, we filed a request with FERC for authority to issue short-term securities and to pledge mortgage bonds in order to increase the size of our revolving credit facility to $750.0 million. On February 15, 2008, FERC granted our request and on February 22, 2008, a syndicate of banks in our credit facility increased their commitments, which in the aggregate total $750.0 million. As of February 22, 2008, $270.0 million had been borrowed and $55.0 million of letters of credit had been issued, leaving $425.0 million available under this facility.

Information regarding our short-term borrowings is as follows.

As of December 31,	2007	2006
	(Dollars in Thousands)	
Weighted average short-term debt outstanding during the year	$157,372	$122,392
Weighted daily average interest rates during the year, excluding fees	5.83%	5.71%

Our interest expense on short-term debt was $9.7 million in 2007, $7.6 million in 2006 and $1.3 million in 2005.

10. LONG-TERM DEBT

Outstanding Debt

The following table summarizes our long-term debt outstanding.

As of December 31,	2007	2006
	(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	—
	1,050,000	900,000
Pollution control bond series:		
Variable due 2032, 4.35% as of December 31, 2007; 3.65% as of December 31, 2006	45,000	45,000
Variable due 2032, 4.35% as of December 31, 2007; 3.55% as of December 31, 2006	30,500	30,500
5.000% due 2033	58,340	58,340
	133,840	133,840
Other long-term debt:		
4.360% Equipment financing loan due 2010	1,825	—
7.125% unsecured senior notes due 2009	145,078	145,078
	146,903	145,078
KGE		
First mortgage bond series:		
6.530% due 2037	175,000	—
	175,000	—
Pollution control bond series:		
5.100% due 2023	13,463	13,488
Variable due 2027, 5.25% as of December 31, 2007; 3.50% as of December 31, 2006	21,940	21,940
5.300% due 2031	108,600	108,600
5.300% due 2031	18,900	18,900
Variable due 2031, 5.00% as of December 31, 2007; 3.47% as of December 31, 2006	100,000	100,000
Variable due 2032, 5.25% as of December 31, 2007; 3.45% as of December 31, 2006	14,500	14,500
Variable due 2032, 4.50% as of December 31, 2007; 3.44% as of December 31, 2006	10,000	10,000
4.850% due 2031	50,000	50,000
Variable due 2031, 5.25% as of December 31, 2007; 3.85% as of December 31, 2006	50,000	50,000
	387,403	387,428
Total long-term debt	1,893,146	1,566,346
Unamortized debt discount[(a)]	(2,807)	(3,081)
Long-term debt due within one year	(558)	—
Long-term debt, net	$1,889,781	$1,563,265

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

The Westar Energy mortgage and the KGE mortgage each contain provisions restricting the amount of first mortgage bonds that could be issued by each entity. We must comply with such restrictions prior to the issuance of additional first mortgage bonds or other secured indebtedness.

The amount of Westar Energy's first mortgage bonds authorized by its Mortgage and Deed of Trust, dated July 1, 1939, as supplemented, is unlimited subject to certain limitations as described below. The amount of KGE's first mortgage bonds authorized by the KGE Mortgage and Deed of Trust, dated April 1, 1940, as supplemented, is limited to a maximum of $2.0 billion, unless amended. First mortgage bonds are secured by utility assets. Amounts of additional bonds that may be issued are subject to property, earnings and certain restrictive provisions, except in connection with certain refundings, of each mortgage. As of December 31, 2007, based on an assumed interest rate of 6%, $408.0 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, 2007, based on an assumed interest rate of 6%, approximately $820.1 million principal amount of additional KGE first mortgage bonds could be issued under the most restrictive provisions in KGE's mortgage.

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. Proceeds from the offering were used to repay borrowings under our revolving credit facility, which is the primary liquidity facility for acquiring capital equipment, and any remainder was used for working capital and general corporate purposes.

On May 16, 2007, Westar Energy sold $150.0 million aggregate principal amount of 6.1% Westar Energy first mortgage bonds maturing in 2047. Proceeds from the offering were used to repay borrowings under our revolving credit facility, which is the primary liquidity facility for acquiring capital equipment, and any remainder was used for working capital and general corporate purposes.

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

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

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, 2007.

Maturities

Maturities of long-term debt as of December 31, 2007, are as follows.

Year	Principal Amount
	(In Thousands)
2008	$ 558
2009	145,684
2010	633
2011	28
Thereafter	1,746,243
Total long-term debt maturities	$1,893,146

Our interest expense on long-term debt was $94.2 million in 2007, $91.0 million in 2006 and $107.8 million in 2005.

11. TAXES

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

Year Ended December 31,	2007	2006	2005
		(In Thousands)	
Income Tax Expense (Benefit) from Continuing Operations:			
Current income taxes:			
Federal	$40,648	$46,211	$ 30,132
State	9,107	14,303	4,829
Deferred income taxes:			
Federal	9,962	(1,150)	24,831
State	6,240	578	3,511
Investment tax credit amortization	(2,118)	(3,630)	(2,790)
Income tax expense from continuing operations	63,839	56,312	60,513
Income Tax Expense from Discontinued Operations:			
Current income taxes:			
Federal	—	—	29
State	—	—	7
Deferred income taxes:			
Federal	—	—	370
State	—	—	84
Income tax expense from discontinued operations	—	—	490
Total income tax expense	$63,839	$56,312	$ 61,003

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

December 31,	2007	2006
	(In Thousands)	
Current deferred tax assets	$ —	$ 853
Current deferred tax liabilities	2,310	—
Non-current deferred tax liabilities	897,293	906,311
Net deferred tax liabilities	$899,603	$905,458

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,	2007	2006
	(In Thousands)	
Deferred tax assets:		
Deferred gain on sale-leaseback	$ 52,616	$ 54,978
Accrued liabilities	29,248	30,531
Disallowed costs	15,301	15,955
Long-term energy contracts	8,262	9,314
Deferred employee benefit costs	82,752	77,155
Capital loss carryforward[a]	216,626	219,795
Other[b]	93,796	74,963
Total gross deferred tax assets	498,601	482,691
Less: Valuation allowance[a]	220,146	223,227
Deferred tax assets	$ 278,455	$ 259,464
Deferred tax liabilities:		
Accelerated depreciation	$ 644,707	$ 642,493
Acquisition premium	219,985	227,999
Amounts due from customers for future income taxes, net	151,279	160,147
Deferred employee benefit costs	79,693	74,111
Other	82,394	60,172
Total deferred tax liabilities	$1,178,058	$1,164,922
Net deferred tax liabilities	$ 899,603	$ 905,458

[a] *As of December 31, 2007, we have a net capital loss of $544.6 million available to offset any future capital gains through 2009. However, as we do not expect to realize any significant capital gains in the future, a valuation allowance of $216.6 million has been established. In addition, a valuation allowance of $3.5 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 $220.1 million as of December 31, 2007, and $223.2 million as of December 31, 2006. The net reduction in valuation allowance of $3.1 million was due primarily to capital gains realized in 2007. See the discussion below regarding the filing of amended Federal income tax returns for years 2003 and 2004.*

[b] *As of December 31, 2006, we had available general business tax credits of $0.5 million generated from affordable housing partnerships in which we sold the majority of our interests in 2001. These tax credits expire beginning 2019 through 2025. We believe these tax credits will be fully utilized on the 2007 tax return.*

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,	2007	2006	2005
Statutory Federal income tax rate from continuing operations	35.0 %	35.0 %	35.0 %
Effect of:			
State income taxes	4.4	4.4	2.8
Amortization of investment tax credits	(0.9)	(1.6)	(1.4)
Corporate-owned life insurance policies	(5.8)	(8.3)	(6.9)
Accelerated depreciation flow through and amortization	2.1	1.4	1.2
Net operating loss utilization	(5.1)	(0.9)	(0.2)
Capital loss utilization	(1.2)	(4.0)	(0.8)
Other	(1.0)	(0.6)	1.3
Effective income tax rate from continuing operations	27.5 %	25.4 %	31.0 %
Statutory Federal income tax rate from discontinued operations	— %	— %	35.0 %
Effect of:			
State income taxes	—	—	4.8
Effective income tax rate from discontinued operations	— %	— %	39.8 %

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 Internal Revenue Service (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 1995.

The IRS has examined our Federal income tax returns for the years 1995 through 2002. We reached a tentative settlement with the IRS Office of Appeals (IRS Appeals Settlement) in December 2007. The principal issues related to the method for capitalizing and allocating overhead costs, the carry back of capital losses and net operating losses and the deduction of and credit for research and development costs. The IRS Appeals Settlement was approved by the Joint Committee on Taxation and accepted by the IRS in February 2008. As a result, we will receive a tax refund of approximately $18.8 million, excluding interest. The Federal statute of limitations for years 1995 through 2002 remains open until 90 days after either the IRS or we send the prescribed notice ending the agreement. We believe that the statute of limitations for the affected years will close within the next 12 months.

The IRS is currently examining our Federal income tax returns for years 2003 and 2004. On December 21, 2007, we filed amended Federal income tax returns for years 2003 and 2004. The amended returns change the original Federal income tax characterization of the loss we incurred on the sale of Protection One, Inc. (Protection One) in 2004 from a capital loss to an ordinary loss. The characterization of the loss as either capital or ordinary affects our ability to carry back and carry forward the loss to tax years in which the loss can be deducted. The IRS has challenged the position reported on the amended returns and the ultimate outcome cannot be predicted at this time. If the re-characterization of the tax loss is ultimately upheld, the loss would be available for carry back to year 2003 and carried forward 20 years to offset future taxable income. In addition, under the terms of our tax sharing agreement, we reimburse subsidiaries for current tax benefits used in our consolidated tax return. Under a settlement agreement relating to the sale transaction, we agreed to reimburse Protection One an amount equal to 50% of the tax benefit attributable to the net operating loss carryforward arising from the sale. As shown below, we have not recognized tax benefits related to the amended returns. The IRS has not paid us a refund and, thus, the unrecognized tax benefits related to this uncertain tax position do not constitute liabilities. We believe that it is reasonably possible that the examination of years 2003 and 2004 will be completed by the end of 2008. We have extended the statute of limitations for these years until December 31, 2008.

Our 2007, 2006 and 2005 income tax returns are subject to audit by Federal and state taxing authorities.

We adopted the provisions of FIN 48 as of January 1, 2007. The cumulative effect of adopting FIN 48 was an increase of $10.5 million to the January 1, 2007, retained earnings balance.

At January 1, 2007, the amount of unrecognized tax benefits and the FIN 48 liability were $50.2 million. During the year 2007, the FIN 48 liability increased to $70.8 million and the amount of unrecognized tax benefits increased to $209.6 million. The net increase in FIN 48 liability is primarily attributable to the deductions related to the December 2007 ice storm. It is reasonably possible that a reduction of unrecognized tax benefits in the range of $39.9 million to $178.7 million may occur in the next 12 months due to the expiration of the statute of limitations with respect to years 1995 through 2002 and developments pertaining to the examination of years 2003 and 2004. A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

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

As of December 31, 2007, the amount of unrecognized tax benefits that, if recognized, would favorably impact our effective tax rate, is $172.2 million (net of tax). Included in the FIN 48 liability at December 31, 2007, are $33.4 million (net of tax) of tax positions, which if recognized, would favorably impact our effective income tax rate.

With the adoption of FIN 48, we changed our practice of including interest related to income tax uncertainties in income tax expense. Effective January 1, 2007, interest is classified as interest expense and accrued interest liability. We had $13.5 million and $18.9 million accrued for interest related to income tax liabilities at December 31, 2007, and January 1, 2007, respectively. There were no penalties accrued at December 31, 2007, or January 1, 2007, and no penalties were recognized during 2007.

As of December 31, 2007 and 2006, we maintained reserves of $5.2 million and $6.9 million, respectively, for probable assessments of taxes other than income taxes.

12. EMPLOYEE BENEFIT PLANS

Pension

We maintain a qualified non-contributory defined benefit pension plan covering substantially all of our employees. For the majority of our employees, pension benefits are based on years of service and the employee's compensation during the 60 highest paid consecutive months out of 120 before retirement. Our funding policy for the pension plan is to contribute amounts sufficient to meet the minimum funding requirements under the Employee Retirement Income Security Act of 1974 (ERISA) and the Internal Revenue Code plus additional amounts as considered appropriate. Non-union employees hired after December 31, 2001, are covered by the same defined benefit plan with benefits derived from a cash balance account formula. We also maintain a non-qualified Executive Salary Continuation Plan for the benefit of certain current and retired officers.

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

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

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

As of December 31,	Pension Benefits 2007	Pension Benefits 2006	Post-retirement Benefits 2007	Post-retirement Benefits 2006
	(In Thousands)			
Change in Benefit Obligation:				
Benefit obligation, beginning of year	$ 551,728	$ 549,132	$ 124,546	$ 128,185
Service cost	9,641	9,178	1,548	1,492
Interest cost	32,418	30,522	7,574	6,875
Plan participants' contributions	—	—	4,164	3,380
Benefits paid	(28,450)	(28,345)	(11,481)	(11,306)
Actuarial losses (gains)	12,718	(8,759)	(5,994)	(4,080)
Amendments	136	—	13,778	—
Benefit obligation, end of year	$ 578,191	$ 551,728	$ 134,135	$ 124,546
Change in Plan Assets:				
Fair value of plan assets, beginning of year	$ 451,824	$ 422,300	$ 52,778	$ 44,196
Actual return on plan assets	31,208	35,302	3,215	3,374
Employer contribution	11,800	20,750	12,400	12,200
Plan participants' contributions	—	—	4,030	3,380
Part D Reimbursements	—	—	814	677
Benefits paid	(26,644)	(26,528)	(11,814)	(11,049)
Fair value of plan assets, end of year	$ 468,188	$ 451,824	$ 61,423	$ 52,778
Funded status, end of year	$(110,003)	$ (99,904)	$ (72,712)	$ (71,768)
Amounts Recognized in the Balance Sheets Consist of:				
Current liability	$ (1,838)	$ (1,930)	$ (130)	$ —
Noncurrent liability	(108,165)	(97,974)	(72,582)	(71,768)
Net amount recognized	$(110,003)	$ (99,904)	$ (72,712)	$ (71,768)
Amounts Recognized in Regulatory Assets Consist of:				
Net actuarial loss	$ 114,325	$ 102,172	$ 19,636	$ 26,570
Prior service cost	11,517	13,926	12,858	17
Transition obligation	—	—	19,979	23,909
Net amount recognized	$ 125,842	$ 116,098	$ 52,473	$ 50,496

As of December 31,	Pension Benefits 2007	Pension Benefits 2006	Post-retirement Benefits 2007	Post-retirement Benefits 2006
	(Dollars in Thousands)			
Pension Plans With a Projected Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$ 578,191	$ 551,728	$ —	$ —
Accumulated benefit obligation	497,169	483,511	—	—
Fair value of plan assets	468,188	451,824	—	—
Pension Plans With an Accumulated Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$ 578,191	$ 551,728	$ —	$ —
Accumulated benefit obligation	497,169	483,511	—	—
Fair value of plan assets	468,188	451,824	—	—
Post-retirement Plans With an Accumulated Post-retirement Benefit Obligation In Excess of Plan Assets:				
Accumulated post-retirement benefit obligation	$ —	$ —	$ 134,135	$ 124,546
Fair value of plan assets	—	—	61,423	52,778
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Benefit Obligation:				
Discount rate	6.25%	5.90%	6.10%	5.80%
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 Emerging Issues Task Force (EITF) No. D-36, "Selection of Discount Rates Used for Measuring Defined Benefit Pension Obligations and Obligations of Post Retirement Benefit Plans Other Than Pensions." The yield curve is constructed based on the yields on over 500 high-quality, non-callable corporate bonds with maturities between zero and 30 years. A theoretical spot rate curve constructed from this yield curve is then used to discount the annual benefit cash flows of our pension plan and develop a single-point discount rate matching the plan's payout structure.

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

Year Ended December 31,	Pension Benefits 2007	2006	2005
	(Dollars in Thousands)		
Components of Net Periodic Cost (Benefit):			
Service cost	$ 9,641	$ 9,178	$ 6,735
Interest cost	32,418	30,522	28,764
Expected return on plan assets	(38,506)	(35,939)	(36,272)
Amortization of unrecognized:			
Transition obligation, net	—	—	—
Prior service costs/(benefit)	2,545	2,892	2,761
Actuarial loss, net	7,864	8,759	5,347
Net periodic cost	$13,962	$15,412	$ 7,335
Other Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets:			
Current year actuarial (gain)/loss	$20,017	$ —	$ —
Amortization of actuarial loss	(7,864)	—	—
Current year prior service cost	136	—	—
Amortization of prior service cost	(2,545)	—	—
Amortization of transition obligation	—	—	—
Total recognized in regulatory assets	$ 9,744	$ —	$ —
Total recognized in net periodic cost and regulatory assets	$23,706	$15,412	$ 7,335
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost (Benefit):			
Discount rate	5.90%	5.65%	5.90%
Expected long-term return on plan assets	8.50%	8.50%	8.75%
Compensation rate increase	4.00%	3.50%	3.00%

Year Ended December 31,	Post-retirement Benefits 2007	2006	2005
	(Dollars in Thousands)		
Components of Net Periodic Cost (Benefit):			
Service cost	$ 1,548	$ 1,492	$ 1,615
Interest cost	7,574	6,875	7,049
Expected return on plan assets	(3,827)	(2,971)	(2,552)
Amortization of unrecognized:			
Transition obligation, net	3,930	3,931	3,931
Prior service costs/(benefit)	937	(415)	(467)
Actuarial loss, net	1,503	2,001	1,934
Net periodic cost	11,665	$10,913	$ 11,510
Other Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets:			
Current year actuarial (gain)/loss	$(5,431)	$ —	$ —
Amortization of actuarial loss	(1,503)	—	—
Current year prior service cost	13,778	—	—
Amortization of prior service cost	(937)	—	—
Amortization of transition obligation	(3,930)	—	—
Total recognized in regulatory assets	$ 1,977	$ —	$ —
Total recognized in net periodic cost and regulatory assets	$13,642	$10,913	$ 11,510
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost (Benefit):			
Discount rate	5.80%	5.65%	5.90%
Expected long-term return on plan assets	7.75%	7.75%	8.25%
Compensation rate increase	—	—	—

The estimated amounts that will be amortized from regulatory assets into net periodic benefit cost in 2008 are as follows:

	Pension Benefits	Other Post-retirement Benefits
	(In Thousands)	
Actuarial loss	$ 8,340	$ 1,404
Prior service cost	2,545	1,412
Transition obligation	—	3,930
Total	$10,885	$ 6,746

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

In December 2003, the Medicare Prescription Drug Improvement and Modernization Act of 2003 (Medicare Act) became law. The Medicare Act introduced a prescription drug benefit under Medicare as well as a federal subsidy beginning in 2006. This subsidy will be paid to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare. We believe our retiree health care benefits plan is at least actuarially equivalent to Medicare and is eligible for the federal subsidy. We adopted the guidance in the third quarter of 2004. Treating the future subsidy under the Medicare Act as an actuarial experience gain, as required by the guidance, decreased the accumulated post-retirement benefit obligation by approximately $4.6 million in both 2007 and 2006. The subsidy also decreased the net periodic post-retirement benefit cost by approximately $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,	2007	2006
Health care cost trend rate assumed for next year	8.00%	9.00%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	5.00%	5.00%
Year that the rate reaches the ultimate trend rate	2014	2011

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	$ 15	$ (18)
Effect on post-retirement benefit obligation	144	(249)

The asset allocation for the pension plans and the post-retirement benefit plans at the end of 2007 and 2006, and the target allocations for 2008, by asset category, are as shown in the following table.

	Target Allocations	Plan Assets	
Asset Category	2008	2007	2006
Pension Plans:			
Equity securities	65%	67%	62%
Debt securities	35%	29%	35%
Cash	0% - 5%	4%	3%
Total		100%	100%
Post-retirement Benefit Plans:			
Equity securities	65%	60%	64%
Debt securities	30%	29%	28%
Cash	5%	11%	8%
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. Investments are diversified across classes, sectors and manager style to minimize the risk of large losses. We delegate investment management to specialists in each asset class and where appropriate, provide the investment manager with specific guidelines, which include allowable and/or prohibited investment types. Investment risk is measured and monitored on an ongoing basis through quarterly investment portfolio reviews and annual liability measurements.

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

	Pension Benefits		Post-retirement Benefits	
Expected Cash Flows	To/(From) Trust	To/(From) Company Assets	To/(From) Trust	To/(From) Company Assets
		(In Millions)		
Expected contributions:				
2008[(a)]	$ 15.2	$ 1.8	$ 12.6	$ 0.1
Expected benefit payments:				
2008	$ (26.5)	$ (1.8)	$ (8.0)	$ (0.1)
2009	(26.5)	(1.8)	(8.3)	(0.1)
2010	(26.8)	(1.8)	(8.5)	(0.1)
2011	(27.4)	(1.8)	(8.7)	(0.1)
2012	(28.2)	(1.8)	(8.8)	(0.1)
2013 - 2017	(167.5)	(9.1)	(49.1)	(0.7)

[(a)] *We expect to make a voluntary contribution of $15.2 million to the Westar Energy pension trust in 2008.*

In September 2006, FASB released SFAS No. 158. Under the new standard, companies must recognize a net liability or asset to report the funded status of their defined benefit pension and other post-retirement benefit plans on their balance sheets. On December 31, 2006, we adopted the recognition and disclosure provisions of SFAS No. 158. The effect of adopting SFAS No. 158 on our financial condition at December 31, 2006, has been included in the accompanying consolidated financial statements. We received an accounting authority order from the KCC to recognize as a regulatory asset the pension and post-retirement liabilities that otherwise would have been charged to other comprehensive income.

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

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

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

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 $5.6 million in 2007, $4.8 million in 2006 and $4.1 million in 2005.

Stock Based Compensation Plans

We have a long-term incentive and share award plan (LTISA Plan), which is a stock-based compensation plan in which employees and directors are eligible for awards. The LTISA Plan was implemented as a means to attract, retain and motivate employees and directors. Under the LTISA Plan, we may grant awards in the form of stock options, dividend equivalents, share appreciation rights, RSUs, performance shares and performance share units to plan participants. Up to five million shares of common stock may be granted under the LTISA Plan. As of December 31, 2007, awards of 3,981,261 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. On March 29, 2005, the Securities and Exchange Commission (SEC) staff issued Staff Accounting Bulletin (SAB) No. 107 on Share-Based Payment to express the views of the staff regarding the interaction between SFAS No. 123R and SEC rules and regulations as well as provide staff's view on valuation of stock-based compensation arrangements for public companies. The SAB No. 107 guidance was taken into consideration with the implementation of SFAS No. 123R.

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

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

Twelve Months Ended December 31,	2007	2006	2005
		(In Thousands)	
Compensation expense	$ 5,735	$ 3,395	$4,560
Income tax benefits related to stock-based compensation arrangements	2,281	1,350	1,814

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

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, 2007, our RSU activity was as follows:

As of December 31,	2007		2006		2005	
	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	933.4	$20.82	1,094.5	$ 18.54	1,298.4	$ 17.50
Granted	413.8	26.76	160.3	23.91	135.5	22.04
Vested	(308.5)	20.53	(306.6)	14.96	(336.0)	13.28
Forfeited	(54.5)	26.79	(14.8)	21.56	(3.4)	20.43
Nonvested balance, end of year	984.2	23.11	933.4	20.82	1,094.5	18.54

Total unrecognized compensation cost related to RSU awards was $8.9 million as of December 31, 2007. These costs are expected to be recognized over a remaining weighted-average period of 2.4 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, 2007, 2006 and 2005, was $8.3 million, $7.2 million and $7.5 million, respectively. There were no modifications of awards during the years ended December 31, 2007, 2006 or 2005.

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, 2007, we had $5.2 million of temporary equity on our consolidated balance sheet. If we determine it is probable that these awards will be settled in cash, the awards will be reclassified as a liability.

Stock options granted between 1997 and 2001 are completely vested and expire 10 years from the date of grant. All 77,290 outstanding options are exercisable. There were no options exercised and 83,190 options forfeited during the year ended December 31, 2007. We currently have no plans to issue new stock option awards.

Another component of the LTISA Plan is the Executive Stock for Compensation program, where in the past eligible employees were entitled to receive deferred stock in lieu of current cash compensation. Although this plan was discontinued in 2001, dividends will continue to be paid to plan participants on their outstanding plan balance until distribution. Plan participants were awarded 4,214 shares of common stock for dividends in 2007, 4,407 shares in 2006 and 3,936 shares in 2005. Participants received common stock distributions of 505 shares in 2007, 1,936 shares in 2006 and 12,271 shares in 2005.

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

13. WOLF CREEK EMPLOYEE BENEFIT PLANS

Pension and Post-retirement Benefits

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

	Pension Benefits		Post-retirement Benefits	
As of December 31,	2007	2006	2007	2006
	(In Thousands)			
Change in Benefit Obligation:				
Benefit obligation, beginning of year	$ 79,213	$ 71,537	$ 7,391	$ 7,005
Service cost	3,436	3,245	234	248
Interest cost	4,696	4,293	435	412
Plan participants' contributions	—	—	294	253
Benefits paid	(1,809)	(1,185)	(509)	(610)
Actuarial losses/(gains)	2,071	1,278	(114)	83
Amendments	34	45	—	—
Curtailments, settlements and special termination benefits	2,205	—	865	—
Benefit obligation, end of year	$ 89,846	$ 79,213	$ 8,596	$ 7,391
Change in Plan Assets:				
Fair value of plan assets, beginning of year	$ 47,869	$ 39,752	$ —	$ —
Actual return on plan assets	3,314	4,346	—	—
Employer contribution	5,618	4,766	—	—
Benefits paid	(1,809)	(995)	—	—
Fair value of plan assets, end of year	$ 54,992	$ 47,869	$ —	$ —
Funded status	$ (34,854)	$ (31,344)	$ (8,596)	$ (7,391)
Post-measurement date adjustments	1,072	1,164	—	—
Accrued post-retirement benefit costs	$ (33,782)	$ (30,180)	$ (8,596)	$ (7,391)
Amounts Recognized in the Balance Sheets Consist of:				
Current liability	$ (168)	$ (190)	$ (632)	$ (347)
Noncurrent liability	(33,614)	(29,990)	(7,964)	(7,044)
Net amount recognized	$ (33,782)	$ (30,180)	$ (8,596)	$ (7,391)
Amounts Recognized in Regulatory Assets Consist of:				
Net actuarial loss	$ 21,120	$ 19,397	$ 3,127	$ 2,531
Prior service cost	178	202	—	—
Transition obligation	227	284	288	346
Net amount recognized	$ 21,525	$ 19,883	$ 3,415	$ 2,877

As of December 31,	Pension Benefits 2007	Pension Benefits 2006	Post-retirement Benefits 2007	Post-retirement Benefits 2006
	(Dollars in Thousands)			
Pension Plans With a Projected Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$ 89,846	$ 79,213	$ —	$ —
Accumulated benefit obligation	68,302	62,339	—	—
Fair value of plan assets	54,992	47,869	—	—
Pension Plans With an Accumulated Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$ 89,846	$ 79,213	$ —	$ —
Accumulated benefit obligation	68,302	62,339	—	—
Fair value of plan assets	54,992	47,869	—	—
Post-retirement Plans With an Accumulated Post-retirement Benefit Obligation In Excess of Plan Assets:				
Accumulated post-retirement benefit obligation	$ —	$ —	$ 8,596	$ 7,931
Fair value of plan assets	—	—	—	—
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Benefit Obligation:				
Discount rate	6.15%	5.70%	6.05%	5.80%
Compensation rate increase	4.00%	3.25%	—	—

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

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

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

Year Ended December 31,	Pension Benefits 2007	Pension Benefits 2006	Pension Benefits 2005
	(Dollars in Thousands)		
Components of Net Periodic Cost:			
Service cost	$ 3,436	$ 3,245	$ 2,820
Interest cost	4,696	4,293	3,730
Expected return on plan assets	(4,101)	(3,428)	(3,114)
Amortization of unrecognized:			
Transition obligation, net	57	57	57
Prior service costs	57	31	31
Actuarial loss, net	1,855	1,813	1,340
Curtailments, settlements and special termination benefits	1,486	—	—
Net periodic cost	$ 7,486	$ 6,011	$ 4,864
Other Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets:			
Current year actuarial loss	$ 3,578	$ —	$ —
Amortization of actuarial loss	(1,855)	—	—
Current year prior service cost	34	—	—
Amortization of prior service cost	(57)	—	—
Amortization of transition obligation	(57)	—	—
Total recognized in regulatory assets	$ 1,643	$ —	$ —
Total recognized in net periodic cost and regulatory assets	$ 9,129	$ 6,011	$ 4,864
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost:			
Discount rate	5.70%	5.75%	6.00%
Expected long-term return on plan assets	8.25%	8.25%	8.75%
Compensation rate increase	3.25%	3.25%	3.00%

Year Ended December 31,	Post-retirement Benefits 2007	Post-retirement Benefits 2006	Post-retirement Benefits 2005
	(Dollars in Thousands)		
Components of Net Periodic Cost:			
Service cost	$ 234	$ 248	$ 238
Interest cost	435	412	384
Expected return on plan assets	—	—	—
Amortization of unrecognized:			
Transition obligation, net	58	58	58
Prior service costs	—	—	—
Actuarial loss, net	191	196	170
Curtailments, settlements and special termination benefits	259	—	—
Net periodic cost	$ 1,177	$ 914	$ 850
Other Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets:			
Current year actuarial loss	$ 786	$ —	$ —
Amortization of actuarial loss	(191)	—	—
Current year prior service cost	—	—	—
Amortization of prior service cost	—	—	—
Amortization of transition obligation	(58)	—	—
Total recognized in regulatory assets	$ 537	$ —	$ —
Total recognized in net periodic cost and regulatory assets	$ 1,714	$ 914	$ 850
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost:			
Discount rate	5.80%	5.75%	6.00%
Expected long-term return on plan assets	—	—	—
Compensation rate increase	—	—	—

In January 2007, Wolf Creek Nuclear Operating Corporation offered a selective retirement incentive to certain 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 benefit cost in 2008 are as follows:

	Pension Benefits	Other Post-retirement Benefits
	(In Thousands)	
Actuarial loss	$ 1,640	$ 219
Prior service cost	57	—
Transition obligation	57	58
Total	$ 1,754	$ 277

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,	2007	2006
Health care cost trend rate assumed for next year	8.0%	9.0%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	5.0%	5.0%
Year that the rate reaches the ultimate trend rate	2014	2011

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	(44)	33

The asset allocation for the pension plans at the end of 2007 and 2006, and the target allocation for 2008, by asset category are as shown in the following table.

	Target Allocations	Plan Assets	
Asset Category	2008	2007	2006
Pension Plans:			
Equity securities	65%	67%	63%
Debt securities	35%	28%	34%
Cash	0%	5%	3%
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:				
2008	$ 5.3	$ 0.2	$ —	$ 0.6
Expected benefit payments:				
2008	$ (2.0)	$ (0.2)	$ —	$ (0.6)
2009	(1.7)	(0.2)	—	(0.4)
2010	(2.0)	(0.2)	—	(0.5)
2011	(2.4)	(0.2)	—	(0.5)
2012	(2.9)	(0.2)	—	(0.5)
2013 – 2017	(24.2)	(0.8)	—	(3.2)

Savings Plan

Wolf Creek maintains a qualified 401(k) savings plan in which most of its employees participate. They match employees' contributions in cash up to specified maximum limits. Wolf Creek's contribution to the plan is deposited with a trustee and is invested at the direction of plan participants into one or more of the investment alternatives provided under the plan. KGE's portion of expense associated with Wolf Creek's matching contributions was $0.9 million in 2007, $0.9 million in 2006 and $0.9 million in 2005.

14. COMMITMENTS AND CONTINGENCIES

Purchase Orders and Contracts

As part of our ongoing operations and construction program, we have purchase orders and contracts, excluding fuel, which is discussed below under "— Purchased Power and Fuel Commitments," that have an unexpended balance of approximately $818.2 million as of December 31, 2007, of which $608.2 million has been committed. The $608.2 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, 2007, was as follows.

	Committed Amount
	(In Thousands)
2008	$ 489,780
2009	93,281
2010	12,911
Thereafter	12,263
Total amount committed	$ 608,235

Clean Air Act

We must comply with the Clean Air Act, state laws and implementing 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 $1.2 billion of capital expenditures at our power plants for environmental air emissions projects during approximately the next eight to ten years. This estimate could increase depending on the resolution of the EPA New Source Review Investigation (NSR Investigation) described below. In addition to the capital investment, in the event we install new equipment as a result of the NSR Investigation, we anticipate that we would incur significant annual expense to operate and maintain the equipment and the operation of the equipment would reduce net production from our plants. The degree to which we will need to reduce emissions and the timing of when such emissions controls may be required is uncertain. Both the timing and the nature of required investments depend on specific outcomes that result from interpretation of existing regulations, new regulations, legislation and the resolution of the NSR Investigation described below. In addition, the availability of equipment and contractors can affect the timing and ultimate cost of the equipment.

The environmental cost recovery rider (ECRR) allows for the timely inclusion in 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 following a rate review.

On August 29, 2007, we filed an application 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 outlined in a proposed agreement filed with the KDHE on August 30, 2007, 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 and particulates between 50% and 65%.

On March 15, 2005, the EPA issued the Clean Air Mercury Rule. The rule caps permanently, and seeks to reduce, the amount of mercury that may be emitted from coal-fired power plants. The rule requires implementation of reductions in two phases, the first starting in 2010. We received an allocation of mercury emission allowances pursuant to the rule. Preliminary testing indicates that the expected allocation of allowances will be insufficient to allow us to operate our coal-fired units in compliance with the first phase requirements of the rule. If the allocated allowances are insufficient, we may need to purchase allowances in the market, install additional equipment or take other actions to reduce our mercury emissions. 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.

We have been in discussions with the EPA and the Department of Justice (DOJ) concerning this matter in an attempt to reach a settlement. We expect that any settlement 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. If settlement discussions fail, DOJ may consider whether to pursue an enforcement action against us in federal district court. Our ultimate costs to resolve the NSR Investigation could be material. We believe that costs related to updating or installing emissions controls would qualify for recovery through the ECRR. 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 clean-ups 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, 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 KCC reviews nuclear decommissioning plans in two phases. Phase one is the approval of the revised nuclear decommissioning study, the current-year funding and future funding. Phase two involves the review and approval by the KCC of a "funding schedule" by the owner of the nuclear facility detailing how it plans to fund the future-year dollar amount of its pro rata share of the plant.

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

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

We recovered in rates and deposited in an external trust fund approximately $2.9 million for nuclear decommissioning in 2007 and $3.9 million in 2006 and 2005. We record our investment in the nuclear decommissioning fund at fair value. The fair value approximated $122.3 million as of December 31, 2007, and $111.1 million as of December 31, 2006.

Storage of Spent Nuclear Fuel

Under the Nuclear Waste Policy Act of 1982, the Department of Energy (DOE) is responsible for the permanent disposal of spent nuclear fuel. As required by federal law, the Wolf Creek co-owners entered into a standard contract with the DOE in 1984 in which the DOE promised to begin accepting from commercial nuclear power plants their used nuclear fuel for disposal beginning in early 1998. In return, Wolf Creek pays into a federal Nuclear Waste Fund administered by the DOE a quarterly fee for the future disposal of spent nuclear fuel. Our share of the fee was $4.4 million in 2007, $4.1 million in 2006 and $3.8 million in 2005 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. The DOE announced in December 2007, that it planned to submit a license application to the NRC no later than June 30, 2008. However, in January 2008, DOE officials announced that that filing date was in jeopardy because of fiscal year 2008 budget allocation reductions. The opening of the Yucca Mountain site has been delayed many times and could be delayed further due to litigation and other issues related to the site as a permanent repository for spent nuclear fuel. Wolf Creek has on-site temporary storage for spent nuclear fuel expected to be generated by Wolf Creek through 2025.

Nuclear Insurance

We maintain nuclear insurance for Wolf Creek in four areas: liability, worker radiation, property and accidental outage. These policies contain certain industry standard exclusions, including, but not limited to, ordinary wear and tear and war. Both the nuclear liability and property insurance programs subscribed to by members of the nuclear power generating industry include industry aggregate limits for non-certified acts, as defined by the Terrorism Risk Insurance Act, of terrorism-related losses, including replacement power costs. An industry aggregate limit of

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

Nuclear Liability Insurance

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

Nuclear Property Insurance

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

Accidental Nuclear Outage Insurance

The owners also carry additional insurance with NEIL to cover costs of replacement power and other extra expenses incurred during a prolonged outage resulting from accidental property damage at Wolf Creek. If significant losses were incurred at any of the nuclear plants insured under the NEIL policies, we may be subject to retrospective assessments under the current policies of approximately $25.7 million (our share is $12.1 million).

Although we maintain various insurance policies to provide coverage for potential losses and liabilities resulting from an accident or an extended outage, our insurance coverage may not be adequate to cover the costs that could result from a catastrophic accident or extended outage at Wolf Creek. Any substantial losses not covered by insurance, to the extent not recoverable through rates, would have a material adverse effect on our consolidated financial condition and results of operations.

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, 2007, our share of Wolf Creek's nuclear fuel commitments were approximately $61.1 million for uranium concentrates expiring in 2016, $9.3 million for conversion expiring in 2016, $153.4 million for enrichment expiring at various times through 2024 and $50.0 million for fabrication in 2024.

As of December 31, 2007, our coal and coal transportation contract commitments in 2007 dollars under the remaining terms of the contracts were approximately $1.4 billion. The largest contract expires in 2020, with the remaining contracts expiring at various times through 2013.

As of December 31, 2007, our natural gas transportation commitments in 2007 dollars under the remaining terms of the contracts were approximately $166.8 million. The natural gas transportation contracts provide firm service to several of our natural gas burning facilities and expire at various times through 2028.

We have entered into power purchase agreements with the owners of two separate wind powered electric generating 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 farms will be approximately $21.0 million. We expect the facilities to be in service by the end of 2008.

15. 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. 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.

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

As of December 31,	2007	2006
	(In Thousands)	
Beginning asset retirement obligations	$ 84,192	$ 129,888
Liabilities incurred	85	218
Liabilities settled	(987)	(737)
Accretion expense	5,421	8,327
Revision to nuclear decommissioning ARO Liability	—	(53,504)
Ending asset retirement obligations	$ 88,711	$ 84,192

In September 2006, WCNOC, the operating company for Wolf Creek, filed a request for a 20 year extension of Wolf Creek's operating license with the NRC. Currently, the operating license will expire in 2025. The NRC's milestone schedule for its review of this request projects a decision by late 2008. The NRC may impose conditions as part of any approval. Based on the experience of other nuclear plant operators, we believe that the NRC will ultimately approve the request. Therefore, we decreased our asset retirement obligation by $53.5 million to reflect the revision in our estimate of the timing of the cash flows that we will incur to satisfy this obligation.

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

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

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

PCB-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.

The recording of the obligation for regulated operations has no income statement impact due to the deferral of the adjustments through the establishment of a regulatory asset pursuant to SFAS No. 71.

Non-Legal Liability — Cost of Removal

We recover in rates, as a component of depreciation, the costs to dispose of utility plant assets that do not represent legal retirement obligations. As of December 31, 2007 and 2006, we had $25.2 million and $13.4 million, respectively, in amounts collected, but unspent, for removal costs classified as a regulatory liability. The net amount related to non-legal retirement costs can fluctuate based on amounts recovered in rates compared to removal costs incurred.

16. LEGAL PROCEEDINGS

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

See also Notes 14 and 17 for discussion of alleged violations of the Clean Air Act, and potential liabilities to David C. Wittig and Douglas T. Lake.

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

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

On June 13, 2003, we filed a demand for arbitration with the American Arbitration Association asserting claims against Mr. Wittig and Mr. Lake arising out of their previous employment with us. Mr. Wittig and Mr. Lake filed counterclaims against us in the arbitration alleging substantial damages related to the termination of their employment and the publication of the report of a special committee of our board of directors. We intend to vigorously defend against these claims. The arbitration has been stayed pending final resolution of criminal charges filed by the United States Attorney's Office against Mr. Wittig and Mr. Lake in U.S. District Court in the District of Kansas. On September 12, 2005, a jury convicted Mr. Wittig and Mr. Lake on the charges relevant to each of them. On January 5, 2007, these convictions were overturned by U.S. Tenth Circuit Court of Appeals following appeals by Mr. Wittig and Mr. Lake. On April 30, 2007, the government announced that it had decided to retry certain charges against Mr. Wittig and Mr. Lake and the retrial is currently scheduled to commence on September 9, 2008. We are unable to predict the ultimate impact of this matter on our consolidated financial statements.

As of December 31, 2007, we had accrued liabilities totaling $76.0 million for compensation not yet paid to Mr. Wittig and Mr. Lake under various agreements and plans. The compensation includes RSU awards, deferred vested shares, deferred RSU awards, deferred vested stock for compensation, executive salary continuation plan benefits, potential obligations related to the cash received for Guardian International, Inc. (Guardian) preferred stock, and, in the case of Mr. Wittig, benefits arising from a split dollar life insurance agreement. The amount of our obligation to Mr. Wittig related to a split dollar life insurance agreement is subject to adjustment at the end of each quarter based on the total return to our shareholders from the date of that agreement. The total return considers the change in our stock price and accumulated dividends. These compensation-related accruals are included in long-term liabilities on the consolidated balance sheets with a portion recorded as a component of paid in capital. The amount accrued will increase annually for future dividends on deferred RSU awards and increases in amounts that may be due under the executive salary continuation plan.

In addition, through December 31, 2007, we have accrued $7.3 million for legal fees and expenses incurred by Mr. Wittig and Mr. Lake that are recorded in accounts payable on our consolidated balance sheets. These legal fees and expenses were incurred by Mr. Wittig and Mr. Lake in the defense of the criminal charges filed by the United States Attorney's Office and the subsequent appeal of convictions on these charges. We have filed lawsuits against Mr. Wittig and Mr. Lake claiming that the legal fees and expenses they have incurred are unreasonable and excessive and we have asked the courts to determine the amount of the legal fees and expenses that were reasonably incurred and which we have an obligation to pay, as well as the amount of the legal fees and expenses that we have an obligation to advance in the future. The U.S. District Court in the lawsuit against Mr. Lake ordered us to pay approximately $3.2 million of the past unpaid fees and expenses and directed us to advance future fees and expenses related to the retrial on a current basis at counsel's customary hourly rates. We appealed this order to the U.S. Tenth Circuit Court of Appeals and asked for a stay of the portion of the order related to the payment of past unpaid fees and expenses. On October 18, 2007, the U.S. Tenth Circuit Court of Appeals denied our request for a stay of the portion of the order related to the payment of past unpaid fees and expenses. Pursuant to the District Court's order, we have paid approximately $3.2 million of Mr. Lake's past unpaid fees and expenses and we have paid approximately $0.9 million for fees and expenses incurred by Mr. Lake in 2007. The issues on appeal other than our request for a stay remain pending before the U.S. Tenth Circuit Court of Appeals. The lawsuit against Mr. Wittig is pending in Shawnee County, Kansas District Court. A special master appointed by the District Court submitted a report in November 2007 finding that $2.5 million of the legal fees and expenses incurred by Mr. Wittig were reasonable and should be paid by us. We submitted objections to the report and the matter is now being reviewed by the District Court. We expect to incur substantial additional expenses for legal fees and expenses that will be incurred by Mr. Wittig and Mr. Lake, but are unable to estimate the amount for which we may ultimately be responsible.

18. GUARDIAN INTERNATIONAL PREFERRED STOCK

On March 6, 2006, Guardian was acquired by Devcon International Corporation in a merger. In connection with this merger, we received approximately $23.2 million for 15,214 shares of Guardian Series D preferred stock and 8,000 shares of Guardian Series E preferred stock held of record by us. We beneficially owned 354.4 shares of the Guardian Series D preferred stock and 312.9 shares of the Guardian Series E preferred stock. We recognized a gain of approximately $0.3 million as a result of this transaction. Certain current and former officers beneficially owned the remaining shares. Of these shares, 14,094 shares of Guardian Series D preferred stock and 7,276 shares of Guardian Series E preferred stock were beneficially owned by Mr. Wittig and Mr. Lake. The ownership of the shares beneficially owned by either Mr. Wittig or Mr. Lake, as well as related dividends, and now the cash received for the shares, is disputed and is the subject of the arbitration proceeding with Mr. Wittig and Mr. Lake discussed in Note 17, "Potential Liabilities to David C. Wittig and Douglas T. Lake." As a result of this transaction, we no longer hold any Guardian securities.

19. 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, 2004	214,363	86,029,721
Issuance of common stock	—	805,650
Balance at December 31, 2005	214,363	86,835,371
Issuance of common stock	—	559,515
Balance at December 31, 2006	214,363	87,394,886
Issuance of common stock	—	8,068,294
Balance at December 31, 2007	214,363	95,463,180

Westar Energy's articles of incorporation, as amended, provide for 150,000,000 authorized shares of common stock. As of December 31, 2007, we had 95,463,180 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 2007, a total of 482,981 shares were issued by Westar Energy through the DSPP and other stock based plans operated under the 1996 LTISA Plan. As of December 31, 2007, a total of 4,339,963 shares were available under the DSPP registration statement.

Common Stock Issuance

On April 12, 2007, we entered into a Sales Agency Financing Agreement with BNY Capital Markets, Inc. (BNYCMI). As of July 12, 2007, we had sold $100.0 million of common stock (3,701,568 shares) through BNYCMI, as agent, pursuant to the agreement. We received $99.0 million in proceeds net of a commission paid to BNYCMI equal to 1% of the sales price of all shares it sold under the agreement. We used the proceeds to repay borrowings under our revolving credit facility, which is the primary liquidity facility for acquiring capital equipment, and any remainder was used for working capital and general corporate purposes.

On August 24, 2007, we entered into a subsequent Sales Agency Financing Agreement with BNYCMI. Under the terms of the agreement, we may offer and sell shares of our common stock from time to time through BNYCMI, as agent, up to an aggregate of $200.0 million for a period of no more than three years. We will pay BNYCMI a commission equal to 1% of the sales price of all shares sold under the agreement. As of December 31, 2007, we had sold $20.0 million of common stock (783,745 shares) through BNYCMI. We received $19.8 million in proceeds net of commission paid to BNYCMI. We used the proceeds to repay borrowings under our revolving credit facility, which is the primary liquidity facility for acquiring capital equipment, and any remainder was used for working capital and general corporate purposes. Pursuant to the same program, in the period January 1, 2008, through February 19, 2008, we sold an additional 75,177 shares for $1.9 million, net of commission.

On November 15, 2007, we entered into a forward equity sale agreement (forward sale agreement) with UBS AG, London Branch (UBS), 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, UBS borrowed an equal number of shares of our common stock from stock lenders and sold the borrowed shares to J.P. Morgan Securities, Inc. (JPM) under an underwriting agreement among Westar Energy, JPM and UBS Securities, LLC, as co-managers for the underwriters. The underwriters subsequently offered the borrowed shares to the public at a price per share of $25.25.

The use of a forward sale agreement allows us to avoid equity market uncertainty by pricing a stock offering under then existing market conditions, while mitigating share dilution by postponing the issuance of stock until funds are needed. Except in specified circumstances or events that would require physical share settlement, we are able to elect to settle the forward sale agreement by means of a physical share, cash or net share settlement and are also able to elect to settle the agreement in whole, or in part, earlier than the stated maturity date at fixed settlement prices. Under a physical share or net share settlement, the maximum number of shares that are deliverable under the terms of the forward sale agreement is limited to 8.2 million shares.

On December 28, 2007, we delivered 3.1 million newly issued shares of our common stock to UBS, 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. Assuming gross share settlement of all remaining shares under the forward sale agreement, we could receive additional aggregate proceeds of approximately $75.0 million, based on a forward price of $24.25 per share for 3.0 million shares. Proceeds from these offerings were used to repay borrowings under our revolving credit facility, which is the primary liquidity facility for acquiring capital equipment, and any remainder was used 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, 2007.

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

The provisions of Westar Energy's articles of incorporation, as amended, contain restrictions on the payment of dividends or the making of other distributions on its common stock while any preferred shares remain outstanding unless certain capitalization ratios and other conditions are met. If the ratio of the capital represented by Westar Energy's common stock, including premiums on its capital stock and its surplus accounts, to its total capital and its surplus accounts at the end of the second month immediately preceding the date of the proposed payment of dividends, adjusted to reflect the proposed payment (capitalization ratio), will be less than 20%, then the payment of the dividends on its common stock shall not exceed 50% of its net income available for dividends for the 12-month period ending with and including the second month immediately preceding the date of the proposed payment. If the capitalization ratio is 20% or more but less than 25%, then the payment of dividends on its common stock, including the proposed payment, shall not exceed 75% of its net income available for dividends for such 12-month period. Except to the extent permitted above, no payment or other distribution may be made that would reduce the capitalization ratio to less than 25%. The capitalization ratio is determined based on the unconsolidated balance sheet for Westar Energy. As of December 31, 2007, 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.

20. 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 22 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:		
2005	$ 23,481	$ 34,239
2006	18,069	32,107
2007	18,069	35,267
Future commitments:		
2008	$ 32,892	$ 48,067
2009	32,964	47,176
2010	33,041	45,870
2011	33,122	43,800
2012	33,209	47,165
Thereafter	289,475	335,470
Total future commitments	$ 454,703	$ 567,548

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

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

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

Capital Leases

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 5 to 14 years depending on the type of vehicle. Computer equipment has either a two- or four-year term.

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,	2007	2006
	(In Thousands)	
Vehicles	$ 27,132	$ 30,009
Computer equipment and software	5,212	4,950
Jeffrey Energy Center 8% interest	118,538	—
Accumulated amortization	(20,576)	(18,115)
Total capital leases	$ 130,306	$ 16,844

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)
2008	$ 17,637
2009	16,757
2010	15,578
2011	15,489
2012	11,378
Thereafter	124,391
	201,230
Amounts representing imputed interest	(69,076)
Present value of net minimum lease payments under capital leases	132,154
Less current portion	(8,300)
Total long-term obligation under capital leases	$ 123,854

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

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

Results of discontinued operations are presented in the table below.

Year Ended December 31,	2005[a]
	(In Thousands, Except Per Share Amounts)
Sales	$ —
Costs and expenses	—
Earnings from discontinued operations before income taxes	—
Estimated gain on disposal	1,232
Income tax expense	490
Results of discontinued operations	$ 742
Basic results of discontinued operations per share	$ 0.01
Diluted results of discontinued operations per share	$ 0.01

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

22. 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.

2007	First	Second	Third	Fourth
	(In Thousands, Except Per Share Amounts)			
Sales	$370,306	$415,178	$548,496	$392,854
Net income	30,175	32,708	91,706	13,765
Earnings available for common stock	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.*

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

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

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, 2007, our disclosure controls and procedures are effective to ensure that information required to be disclosed by us in reports that we file or submit under the Securities Exchange Act of 1934 is accumulated and communicated to the chief executive officer and the chief financial officer, and recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms. 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, 2007, 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 2008 Annual Meeting of Shareholders to be filed pursuant to Regulation 14A (the 2008 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 2008 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 2008 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 2008 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 2008 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 2008 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, 2007 and 2006
Consolidated Statements of Income for the years ended December 31, 2007, 2006 and 2005
Consolidated Statements of Comprehensive Income for the years ended December 31, 2007, 2006 and 2005
Consolidated Statements of Cash Flows for the years ended December 31, 2007, 2006 and 2005
Consolidated Statements of Shareholders' Equity for the years ended December 31, 2007, 2006 and 2005
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
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	#
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
		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

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, 2005				
Allowances deducted from assets for doubtful accounts	$5,313	$3,959	$(4,039)	$5,233
Year ended December 31, 2006				
Allowances deducted from assets for doubtful accounts	$5,233	$5,091	$(4,067)	$6,257
Year ended December 31, 2007				
Allowances deducted from assets for doubtful accounts	$6,257	$3,273	$(3,809)	$5,721

[(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 29, 2008

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)	President, Director and Chief Executive Officer (Principal Executive Officer)	February 29, 2008
/s/ MARK A. RUELLE (Mark A. Ruelle)	Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	February 29, 2008
/s/ CHARLES Q. CHANDLER IV (Charles Q. Chandler IV)	Chairman of the Board	February 29, 2008
/s/ MOLLIE H. CARTER (Mollie H. Carter)	Director	February 29, 2008
/s/ R. A. EDWARDS III (R. A. Edwards III)	Director	February 29, 2008
/s/ JERRY B. FARLEY (Jerry B. Farley)	Director	February 29, 2008
/s/ B. ANTHONY ISAAC (B. Anthony Isaac)	Director	February 29, 2008
/s/ ARTHUR B. KRAUSE (Arthur B. Krause)	Director	February 29, 2008
/s/ SANDRA A. J. LAWRENCE (Sandra A. J. Lawrence)	Director	February 29, 2008
/s/ MICHAEL F. MORRISSEY (Michael F. Morrissey)	Director	February 29, 2008
/s/ JOHN C. NETTELS, JR. (John C. Nettels, Jr.)	Director	February 29, 2008

Construction on the circulating water line replacement on unit 3 at Jeffrey Energy Center.

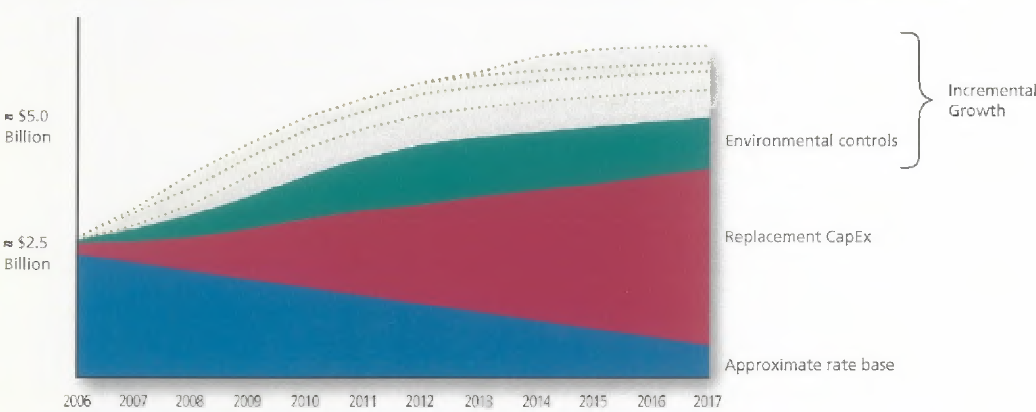
Crews prepare to seal a section of the new water line on unit 3.

We all share the responsibility of being good stewards of the environment.

At Westar Energy, that means doing what it takes to preserve resources and to protect our environment for future generations.

Westar plans to invest about $465 million in environmental projects at Jeffrey Energy Center over the next several years to dramatically decrease air emissions. Projects include rebuilding machinery that removes sulfur dioxide, adding new burners to reduce nitrous oxides and modifying equipment to better capture very small particulate matter. We will also invest to meet new regulations to reduce mercury emissions. We have similar emission control projects lined up at all of our coal plants.

PLANNED CAPITAL EXPANSION



Environmental improvements, represented by the first layer of investment, will reduce the emissions of our existing power plants.

Westar Energy is expanding its transmission network with initiatives that will serve Kansas well into future decades.

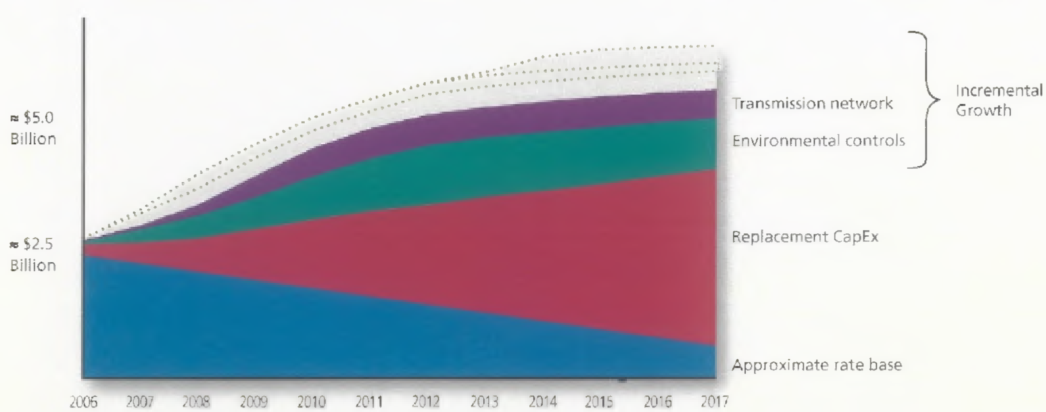
Our planned transmission expansion will also increase the availability of affordable power to Kansans, as well as improve regional reliability. Transmission systems can help ensure the power we have is distributed most efficiently within our state, improve reliability and facilitate the introduction of wind power into our system.

In January 2008 we began constructing the first section of a 345 kilovolt (kV) high-capacity transmission line extending from near Wichita to the Hutchinson area. The remaining section will take the line from Hutchinson to southeast of Salina. We expect to complete construction of this line in late 2009.

We have proposed a 345 kV high-capacity transmission line from near Wichita south to Oklahoma Gas and Electric's system to support current demand, while allowing for growth. We would build the line from south of Wichita to the border of Kansas and Oklahoma. If approved, this project is expected to be serving customers by summer 2011.

Reels of wire at Gordon Evans Energy Center that will be used for the new 345 kV line from Wichita to Hutchinson, and then to Salina. Construction is expected to be complete by late 2009.

PLANNED CAPITAL EXPANSION



Investment in new transmission lines, represented by the next layer of the graph, will increase the reliability of our system and the availability of affordable power throughout the state.

Contractors pour the concrete foundation for a steel pole for phase one of the 345 kV Wichita to Hutchinson to Salina line. Phase one extends from Wichita to Hutchinson. Phase two continues from Hutchinson to Salina.

Contractors construct the 40 foot long rebar cages that will serve as part of the foundation for hundreds of steel poles.

Westar Energy generates electricity using diverse resources – nuclear, coal, natural gas, and, by the end of 2008, wind.

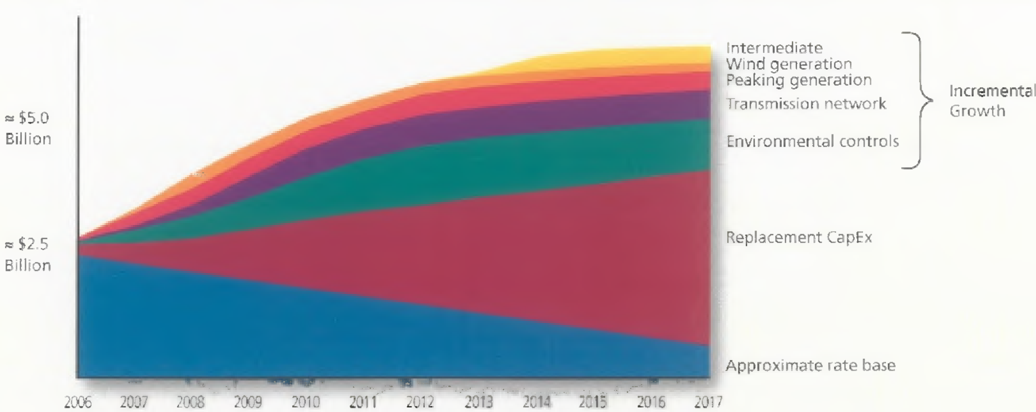
We operate about 6,200 megawatts (MW) of electric generation. We estimate that over the next decade, we will need another 1,100 MW of generation to meet consumer needs. During this time, our nuclear and coal-fueled plants will continue to be important to our generation mix, but we will see natural gas and wind taking larger roles.

Our moderate size makes it important to balance innovation and risk. We have designed our investment plan to provide time for industry developments as technologies mature and regulations evolve. This flexible approach to planning allows us to make better decisions for our customers and shareholders. Our plan allows us to remain nimble and anticipate change.

Water tower at the new Emporia Energy Center.

Overview of Emporia Energy Center construction.

PLANNED CAPITAL EXPANSION



Generation resources account for the remaining layers of our investment plan. Even with successful energy efficiency initiatives, new generation will be needed.

Westar Energy is launching Kansas' largest wind energy program.

By the end of 2008, we will add nearly 300 MW of wind generation to our energy resources, making our program one of the largest utility-sponsored wind programs in the country. Technological advances in recent years have made wind affordable and appealing.

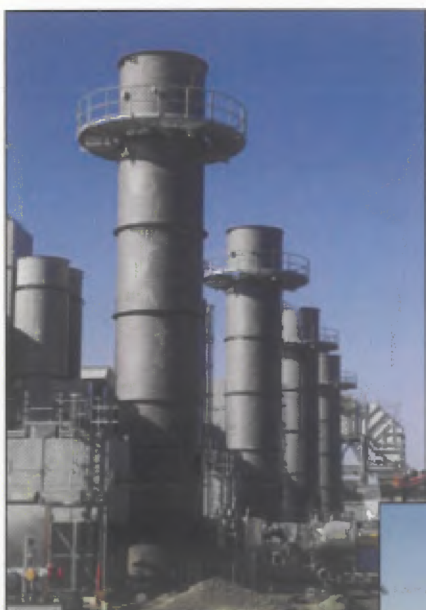
Westar has worked with regulators to ensure recovery of these investments and has signed agreements with developers for three wind farms in different parts of the state. The agreements represent more than a half-billion dollar commitment to wind power in Kansas.

We will bring about 300 MW of wind generation into our generation mix by the end of 2008 with wind farms in Wichita, Barber and Cloud Counties.

Along with energy efficiency and renewable energy, we will need to build additional plants to meet growing needs.

Growth in customers' use of electricity requires us to invest in additional new power plants. We will keep a close eye on market changes, but at this point we expect a highly efficient combined-cycle natural gas plant will be a more cost effective solution than a base load coal plant when it comes time to build more than a peaking plant.

The first phase of our Emporia Energy Center, which is a gas peaking plant, will be available to serve customers this spring and construction of the second phase is scheduled to be complete next spring. This natural gas plant paired with our wind investment will provide reliable electricity for our consumers.



Units at the new Emporia Energy Center.

Larry Graves, Emporia Energy Center plant manager.

Constructive rate mechanisms will benefit shareholders and customers as we grow.

We prepared carefully for this time of growth, working with the Kansas Corporation Commission, our primary regulator, to develop forward-thinking approaches to setting utility rates and to ensure we have the financial capacity to meet growing demands and increasingly uncertain future conditions.

Our Environmental Cost Recovery Rider adjusts each year to reflect investments related to meeting the requirements of the Clean Air Act and other environmental regulations since the prior full review of our rates. Customers benefit because rate changes are more gradual and ultimately lower than they would be without this cost recovery rider. Investors benefit from more timely investment recovery.

Our ability to adjust components of our rates monthly in response to changing fuel prices helps customers understand the cost of their electric service, including the cost of meeting stricter environmental standards, which in turn helps them make better choices to meet their energy needs. In today's volatile fuel markets, it also ensures they are paying the correct price for fuel.

Under a recent state law, Kansas utilities are able to establish with regulators how new generation investment will be recovered in utility rates before a utility makes a substantial commitment to invest. With the rapid changes affecting our industry, this confirms the prudence of these investments and keeps our cost of capital reasonable.

Dustin Spencer, substation apprentice, Topeka Operations Center.

Ryan McCallister, apprentice lineman, and Robert Heath, journeyman lineman, install protective cover up on a line in preparation to provide service to a new commercial customer in DeSoto.

Darrin Hackney, journeyman lineman, loads material at the Shawnee Service Center before heading to the job site.

Construction on the circulating water line replacement on unit 3 at Jeffrey Energy Center.

Transmission lines coming out of Emporia Energy Center.

We are ready for change, but are still steadfast in our mission.

As needs, policies and regulations change, we expect to make adjustments to our investment plan, but our mission and sole business purpose remains the same: Westar Energy provides safe, reliable, high quality electric energy service at a reasonable cost to all customers.

Todd Richardson, apprentice lineman, communicates with crew members as an underground cable is installed for a new residential development in Olathe.

Shareholder Information & Assistance:

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

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

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

Please visit our Web site at **www.WestarEnergy.com.** Registered shareholders can easily access their shareholder account information online by clicking on the **Go to Shareholder Sign-in button.**

CONTACTING SHAREHOLDER SERVICES

TELEPHONE

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

ADDRESS

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

E-MAIL ADDRESS

shareholders@WestarEnergy.com

Please include a daytime telephone number in all correspondence.

CO-TRANSFER AGENT

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

CONTACTING INVESTOR RELATIONS

TELEPHONE (785) 575-8227

ADDRESS

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

E-MAIL ADDRESS

ir@WestarEnergy.com

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

TRUSTEE FOR FIRST MORTGAGE BONDS

PRINCIPAL TRUSTEE, PAYING AGENT AND REGISTRAR

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

CORPORATE INFORMATION

CORPORATE ADDRESS

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

COMMON STOCK LISTING

Ticker Symbol (NYSE): WR

Daily Stock Table Listing:
WestarEngy

CHIEF EXECUTIVE OFFICER AND CHIEF FINANCIAL OFFICER CERTIFICATIONS

In 2007, 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, 2007, were included as exhibits to Westar Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2007, that was filed with the Securities and Exchange Commission.

Directors:

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

CHARLES Q. CHANDLER IV (54)
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 (45)
Director since 2003
Chairman of the Board, President and Chief Executive Officer
Sunflower Banks, Inc.
Salina, Kansas
Committees: Compensation, Finance

R.A. EDWARDS III (62)
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 (61)
Director since 2004
President
Washburn University
Topeka, Kansas
Committees: Audit, Nominating and Corporate Governance

B. ANTHONY ISAAC (54)
Director since 2003
President
LodgeWorks, LP
Wichita, Kansas
Committees: Compensation, Finance

ARTHUR B. KRAUSE (66)
Director since 2003
Executive Vice President and Chief Financial Officer (Retired)
Sprint Corporation
Naples, Florida
Committees: Audit, Finance

SANDRA A.J. LAWRENCE (50)
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 (55)
Director since 2007
President and Chief Executive Officer
Westar Energy, Inc.
Topeka, Kansas

MICHAEL F. MORRISSEY (65)
Director since 2003
Managing Partner (Retired)
Ernst & Young LLP
Naples, Florida
Committees: Audit, Compensation

JOHN C. NETTELS, JR. (51)
Director since 2000
Partner
Stinson Morrison Hecker LLP
Overland Park, Kansas
Committee: Finance

Officers:

WILLIAM B. MOORE (55)
27 years of service
President and Chief Executive Officer

DOUGLAS R. STERBENZ (44)
10 years of service
Executive Vice President and Chief Operating Officer

MARK A. RUELLE (46)
15 years of service
Executive Vice President and Chief Financial Officer

JAMES J. LUDWIG (49)
17 years of service
Executive Vice President, Public Affairs and Consumer Services

BRUCE AKIN (43)
20 years of service
Vice President, Operations Strategy and Support

JEFF BEASLEY (49)
30 years of service
Vice President, Corporate Compliance and Internal Audit

GREG A. GREENWOOD (42)
14 years of service
Vice President, Generation Construction

KELLY B. HARRISON (49)
26 years of service
Vice President, Transmission Operations and Environmental Services

LARRY D. IRICK (51)
8 years of service
Vice President, General Counsel and Corporate Secretary

KENNETH C. JOHNSON (54)
6 years of service
Vice President, Generation

MICHAEL LENNEN (62)
1 year of service
Vice President, Regulatory Affairs

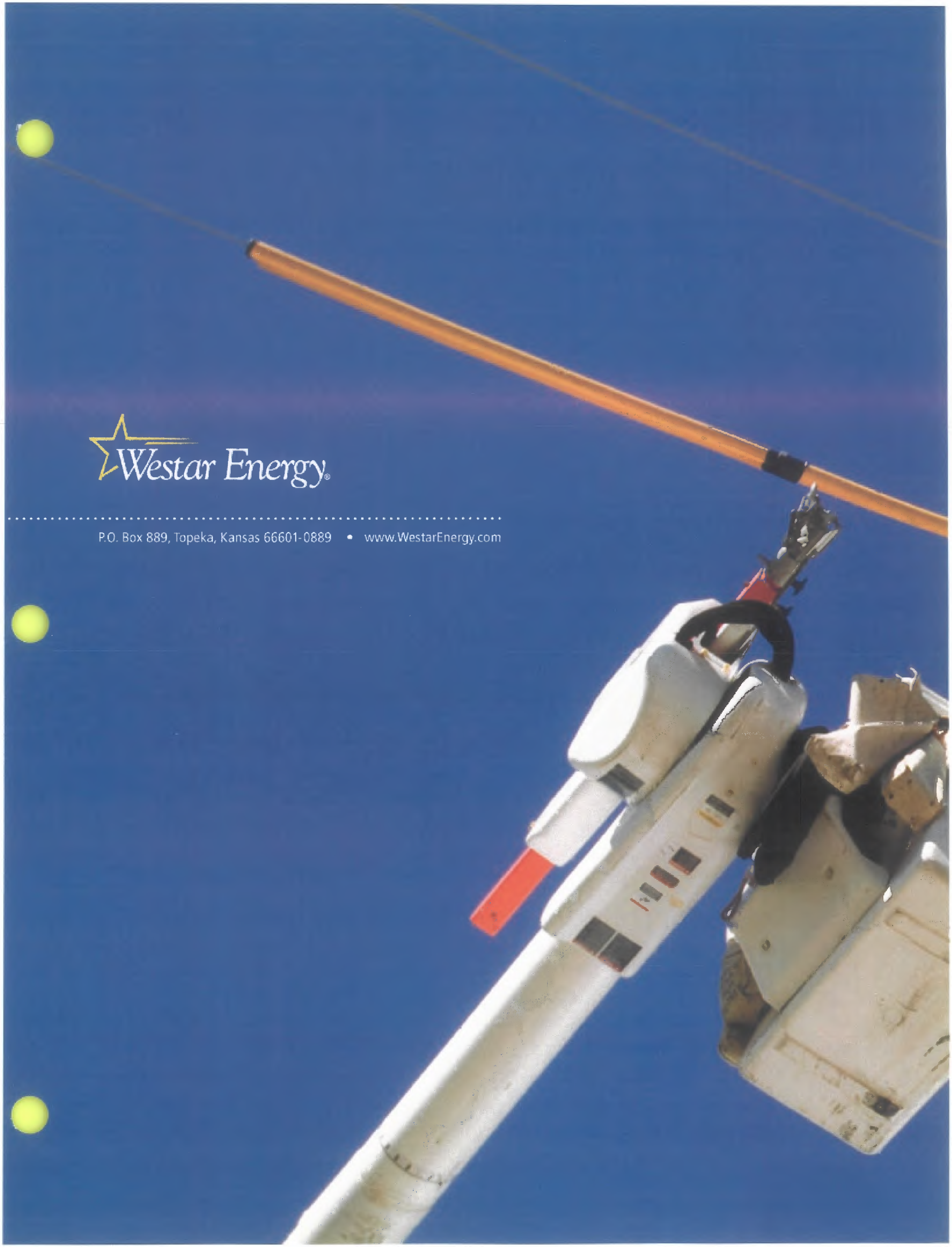
PEGGY S. LOYD (50)
29 years of service
Vice President, Customer Care

ANTHONY D. SOMMA (44)
13 years of service
Treasurer

LEE WAGES (59)
30 years of service
Vice President, Controller

CAROLINE A. WILLIAMS (51)
32 years of service
Vice President, Distribution Power Delivery

Ages and years of service are as of December 31, 2007.



Westar Energy®

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