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

FORM 10-K

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

For the fiscal year ended December 31, 2010

OR

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

For the transition period from __________ to __________

Commission File Number 1-3523

WESTAR ENERGY, INC.
(Exact name of registrant as specified in its charter)

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

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

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

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

Common Stock, par value $5.00 per share First Mortgage Bonds, 6.10% Series due 2047	New York Stock Exchange New York Stock Exchange
(Title of each class)	(Name of each exchange on which registered)

Securities registered pursuant to section 12(g) of the Act:
Preferred Stock, 4-1/2% Series, $100 par value
(Title of Class)

Indicate by check mark whether the registrant is a well-known seasoned issuer (as defined in Rule 405 of the Act). Yes _X_ No ____

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes _X_ No ____

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

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

Large accelerated filer _X_ Accelerated filer ____ Non-accelerated filer ____ Smaller reporting company ____

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

The aggregate market value of the voting common equity held by non-affiliates of the registrant was approximately $2,391,619,392 at June 30, 2010.

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

Common Stock, par value $5.00 per share	113,566,796 shares
(Class)	(Outstanding at February 15, 2011)

DOCUMENTS INCORPORATED BY REFERENCE:

Description of the document	Part of the Form 10-K
Portions of the Westar Energy, Inc. definitive proxy statement to be used in connection with the registrant's 2010 Annual Meeting of Shareholders	Part III (Item 10 through Item 14) (Portions of Item 10 are not incorporated by reference and are provided herein)

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GLOSSARY OF TERMS

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

Abbreviation or Acronym	Definition
AFUDC	Allowance for funds used during construction
ARO	Asset retirement obligation
BACT	Best Available Control Technology
BNSF	Burlington Northern Santa Fe Railway
Btu	British thermal units
CAMR	Clean Air Mercury Rule
CATR	Clean Air Transport Rule
CCB	Coal combustion byproduct
CO_2	Carbon dioxide
COLI	Corporate-owned life insurance
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
DOE	Department of Energy
DOJ	Department of Justice
DSPP	Direct Stock Purchase Plan
ECRR	Environmental Cost Recovery Rider
EPA	Environmental Protection Agency
EPS	Earnings per share
ERISA	Employee Retirement Income Security Act
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Investors Service
GAAP	Generally Accepted Accounting Principles
GHG	Greenhouse gas
INPO	Institute of Nuclear Power Operations
IRS	Internal Revenue Service
JEC	Jeffrey Energy Center
KCC	Kansas Corporation Commission
KCPL	Kansas City Power & Light Company
KDHE	Kansas Department of Health and Environment
KGE	Kansas Gas and Electric Company
kV	Kilovolt
La Cygne	La Cygne Generating Station
LTISA Plan	Long-Term Incentive and Share Award Plan
Medicare Act	Medicare Prescription Drug Improvement and Modernization Act of 2003
MMBtu	Millions of Btu
Moody’s	Moody’s Investors Service
MW	Megawatt(s)
MWh	Megawatt hour(s)
NAAQS	National Ambient Air Quality Standards
NDT	Nuclear Decommissioning Trust
NEIL	Nuclear Electric Insurance Limited
NOx	Nitrogen oxides
NRC	Nuclear Regulatory Commission
NSPS	New Source Performance Standard
ONEOK	ONEOK, Inc.

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OTC	Over-the-counter
PCB	Polychlorinated biphenyl
PRB	Powder River Basin
Protection One	Protection One, Inc.
PSD	Prevention of Significant Deterioration program
RCRA	Resource Conservation and Recovery Act
RECA	Retail energy cost adjustment
RSU	Restricted share unit
RTO	Regional Transmission Organization
S&P	Standard & Poor’s Ratings Group
S&P 500	Standard & Poor’s 500 Index
S&P Electric Utilities	Standard & Poor’s Electric Utility Index
SCR	Selective catalytic reduction
SEC	Securities and Exchange Commission
SO_2	Sulfur dioxide
SPP	Southwest Power Pool
SSCGP	Southern Star Central Gas Pipeline
VaR	Value-at-Risk
VIE	Variable interest entity
Wolf Creek	Wolf Creek Generating Station

FORWARD-LOOKING STATEMENTS

Certain matters discussed in this Annual Report on Form 10-K are “forward-looking statements.” The Private Securities Litigation Reform Act of 1995 has established that these statements qualify for safe harbors from liability. Forward-looking statements may include words like we “believe,” “anticipate,” “target,” “expect,” “estimate,” “intend” and words of similar meaning. Forward-looking statements describe our future plans, objectives, expectations or goals. Such statements address future events and conditions concerning matters such as, but not limited to:

- amount, type and timing of capital expenditures,
- earnings,
- cash flow,
- liquidity and capital resources,
- litigation,
- accounting matters,
- possible corporate restructurings, acquisitions and dispositions,
- compliance with debt and other restrictive covenants,
- interest rates and dividends,
- environmental matters,
- regulatory matters,
- nuclear operations, and
- the overall economy of our service area and its impact on our customers’ demand for electricity and their ability to pay for service.

What happens in each case could vary materially from what we expect because of such things as:

- the risk of operating in a heavily regulated industry subject to frequent and uncertain political, legislative, judicial and regulatory developments at any level of government that can affect our revenues and costs,
- weather conditions and their effect on sales of electricity as well as on prices of energy commodities,
- equipment damage from storms and extreme weather,
- economic and capital market conditions, including the impact of inflation or deflation, changes in interest rates, the cost and availability of capital and the market for trading wholesale energy,
- the impact of changes in market conditions on employee benefit liability calculations, as well as actual and assumed investment returns on invested plan assets,
- the impact of changes in estimates regarding our Wolf Creek Generating Station (Wolf Creek) decommissioning obligation,
- the ability of our counterparties to make payments as and when due and to perform as required,
- the existence of or introduction of competition into markets in which we operate,
- the impact of frequently changing laws and regulations relating to air emissions, water emissions, waste management and other environmental matters,
- risks associated with execution of our planned capital expenditure program, including timing and receipt of regulatory approvals necessary for planned construction and expansion projects as well as the ability to complete planned construction projects within the terms and time frames anticipated,
- cost, availability and timely provision of equipment, supplies, labor and fuel we need to operate our business,
- availability of generating capacity and the performance of our generating plants,
- changes in regulation of nuclear generating facilities and nuclear materials and fuel, including possible shutdown or required modification of nuclear generating facilities,
- uncertainty regarding the establishment of interim or permanent sites for spent nuclear fuel storage and disposal,
- homeland and information security considerations,
- wholesale electricity prices,
- changes in accounting requirements and other accounting matters,

- changes in the energy markets in which we participate resulting from the development and implementation of real time and next day trading markets, and the effect of the retroactive repricing of transactions in such markets following execution because of changes or adjustments in market pricing mechanisms by regional transmission organizations (RTOs) and independent system operators,
- reduced demand for coal-based energy because of climate impacts and development of alternate energy sources,
- current and future litigation, regulatory investigations, proceedings or inquiries,
- other circumstances affecting anticipated operations, electricity sales and costs, and
- other factors discussed elsewhere in this report, including in "Item 1A. Risk Factors" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations," and in other reports we file from time to time with the Securities and Exchange Commission (SEC).

These lists are not all-inclusive because it is not possible to predict all factors. This report should be read in its entirety. No one section of this report deals with all aspects of the subject matter. The reader should not place undue reliance on any forward-looking statement, as forward-looking statements speak only as of the date such statements were made. We undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement was made.

PART I

ITEM 1. BUSINESS

GENERAL

Overview

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

We provide electric generation, transmission and distribution services to approximately 687,000 customers in Kansas. Westar Energy provides these services in central and northeastern Kansas, including the cities of Topeka, Lawrence, Manhattan, Salina and Hutchinson. Kansas Gas and Electric Company (KGE), Westar Energy's wholly-owned subsidiary, provides these services in south-central and southeastern Kansas, including the city of Wichita. Both Westar Energy and KGE conduct business using the name Westar Energy. Our corporate headquarters is located at 818 South Kansas Avenue, Topeka, Kansas 66612.

Strategy

We expect to continue operating as a vertically integrated, regulated, electric utility. We strive to optimize flexibility in our planning and operations to be able to respond to uncertain and changing conditions. Working constructively with our regulators and public officials is also an important part of our strategy.

Significant elements of our strategy include maintaining a flexible and diverse energy supply portfolio. In doing so, presently we are making environmental upgrades to our coal-fired power plants, developing more wind generation and building and upgrading transmission facilities, in addition to developing systems and programs to help our customers use energy more efficiently. Following is a summary of recent progress we have made on significant elements of our strategy.

- During 2010, we made capital expenditures of $111.7 million at our power plants to reduce regulated emissions.
- Along with third parties, in 2008 and 2009 we developed approximately 300 megawatts (MW) of wind generation facilities at three different sites in Kansas, approximately half of which we own and half of which we purchase the renewable energy produced under long-term supply contracts.
- We completed construction of a 345 kilovolt (kV) transmission line in central Kansas in 2010.
- We are implementing SmartStar Lawrence, a smart grid project based in Lawrence, Kansas. Under this project, we will install Advanced Metering Infrastructure equipment to give customers the ability to better monitor their energy use. We qualified to receive a matching grant of approximately $19.0 million from the Department of Energy (DOE), $3.2 million of which we received in 2010. We expect the total project to cost approximately $39.3 million.

Our plans and expectations for 2011 and beyond include:

- Investing approximately $1.0 billion at our power plants over the next three years to reduce regulated emissions.
- On December 14, 2010, we announced that we reached two separate agreements with third parties, subject to regulatory approval, to purchase under 20-year supply contracts the renewable energy produced from approximately 370 MW of wind generation beginning in late 2012.

- We began constructing a 50-mile 345 kV transmission line in south central Kansas.
- Upon receiving all necessary regulatory approvals, Prairie Wind Transmission, LLC, a joint venture company of which we own 50%, intends to construct approximately 110 miles of transmission facilities running from near Wichita, Kansas, southwest to a location near Medicine Lodge, Kansas, and then south to the Oklahoma border.
- In addition to the transmission lines described above, subject to regulatory approvals, we plan to make significant capital expenditures to develop over the next decade additional transmission lines to strengthen Kansas' electrical transmission network.
- We expect to continue improving our distribution system through vegetation management and other programs.
- We expect to continue developing and expanding programs to help customers use energy more efficiently.

OPERATIONS

General

Westar Energy supplies electric energy at retail to approximately 369,000 customers in central and northeast Kansas and KGE supplies electric energy at retail to approximately 318,000 customers in south-central and southeastern Kansas. We supply electric energy at wholesale to municipalities and electric cooperatives in Kansas. We also have contracts for the sale, purchase or exchange of wholesale electricity with other utilities. In addition, we engage in energy marketing and purchase and sell electricity in areas outside our retail service territory.

We have a retail energy cost adjustment (RECA) under which we are permitted to recover in our prices the cost of fuel consumed in generating electricity and purchased power needed to serve our retail customers. Through the RECA, we bill our customers for fuel and purchased power costs based on a quarter-ahead estimate. The RECA provides for an annual review by the Kansas Corporation Commission (KCC) to reconcile estimated and actual fuel and purchased power costs. The KCC uses this same method as the means by which we refund to retail and cost-based wholesale customers the margins we realize from market-based wholesale sales.

Generation Capacity

We have 6,756 MW of accredited generating capacity in service, 2,518 MW of which KGE owns or leases from variable interest entities (VIEs). See "Item 2. Properties" for additional information on our generating units. While we also own wind generation facilities with an installed design capacity of 149 MW, the intermittent nature of this type of production does not create any appreciable amount of accredited capacity. Our capacity and net generation by fuel type is summarized below.

Fuel Type	Capacity (MW)	Percent of Total Capacity	Net Generation (MWh)	Percent of Total Net Generation
Coal	3,437	51%	21,440,267	76%
Nuclear	544	8	4,491,170	16
Natural gas, oil, diesel	2,771	41	1,921,822	7
Wind	4	<1	453,049	1
Total	6,756	100%	28,306,308	100%

In addition to owning and leasing generating capacity, we also have two agreements under which we purchase renewable energy from third parties that own wind generation facilities with a combined installed design capacity totaling 146 MW.

Our aggregate 2010 peak system net load of 5,485 MW occurred on August 12, 2010. This included 137 MW of potentially interruptible load. Our net generating capacity, combined with firm capacity purchases and sales and potentially interruptible load, provided a capacity margin of 20% above system peak responsibility at the time of our 2010 peak system net load.

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

Utility (a)	Capacity (MW)	Expiration
Oklahoma Municipal Power Authority	61	December 2013
ONEOK Energy Services Co.	75	December 2015
Midwest Energy, Inc.	120	May 2016
Mid-Kansas Electric Company, LLC	173	January 2019
Kansas Power Pool	50	March 2020
Midwest Energy, Inc.	135	May 2025
Other	8	June 2011 – May 2015
Total	622	

(a) Under a wholesale agreement that expires in May 2039, we provide base load capacity to the city of McPherson, Kansas, and in return the city provides peaking capacity to us. During 2010, we provided approximately 85 MW to, and received approximately 151 MW from, the city. The amount of base load capacity provided to the city is based on a fixed percentage of its annual peak system load. The city is a full requirements customer of Westar Energy.

Generation Mix

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

Based on MMBtu, our 2010 fuel mix was 78% coal, 15% nuclear and 7% natural gas, with diesel and oil making up less than 1%. Our generation mix fluctuates with the operation of Wolf Creek, variations in fuel costs, plant availability, customer demand, and the cost and availability of power in the wholesale market.

Fossil Fuel Generation

Coal

Jeffrey Energy Center (JEC): The three coal-fired units at JEC have an aggregate capacity of 2,165 MW, of which we own or lease a combined 92% share, or 1,992 MW. We have a long-term coal supply contract with Alpha Natural Resources, Inc. to supply coal to JEC from surface mines located in the Powder River Basin (PRB) in Wyoming. The contract contains a schedule of minimum annual MMBtu delivery quantities. All of the coal used at JEC is purchased under this contract, which expires December 31, 2020. The contract provides for price escalation based on certain costs of production. The price for quantities purchased in excess of the scheduled annual minimum is subject to renegotiation every five years to provide an adjusted price for the ensuing five years that reflects then current market prices. The next re-pricing for those quantities over the scheduled annual minimum will occur in 2013.

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

The average delivered cost of coal consumed at JEC during 2010 was approximately $1.60 per MMBtu, or $26.39 per ton.

La Cygne Generating Station (La Cygne): The two coal-fired units at La Cygne have an aggregate generating capacity of 1,418 MW, of which we own or lease a 50% share, or 709 MW. La Cygne unit 1 uses a blended fuel mix containing approximately 90% PRB coal and 10% Kansas/Missouri coal, the latter of which is purchased from time to time from Kansas and Missouri producers. La Cygne unit 2 uses PRB coal. The operator of La Cygne, Kansas City Power & Light Company (KCPL), arranges coal purchases and transportation services for La Cygne. Approximately 80% of La Cygne unit 1 and unit 2 PRB coal requirements is under contract for 2011. Approximately 50% of the requirements for 2012 and 2013 and 40% of the 2014 requirements are also under contract. Up to 75% of those commitments are fixed price contracts. All of the La Cygne PRB coal is transported under KCPL's rail transportation agreements with BNSF through 2013 and Kansas City Southern Railroad through 2020. As the PRB coal contracts expire, we anticipate that KCPL will negotiate new supply contracts or purchase coal on the spot market.

During 2010, the average delivered cost of our share of coal consumed at La Cygne unit 1 was approximately $1.38 per MMBtu, or $23.23 per ton. The average delivered cost of our share of coal consumed at La Cygne unit 2 was approximately $1.24 per MMBtu, or $20.91 per ton.

Lawrence and Tecumseh Energy Centers: The units located at Lawrence and Tecumseh Energy Centers have an aggregate generating capacity of 773 MW. We purchase PRB coal for these two energy centers under a contract with Arch Coal, Inc., which we expect to provide 100% of the coal requirements for the energy centers through 2012. BNSF transports coal for these energy centers under a contract that expires in December 2013.

During 2010, the average delivered cost of coal consumed in the Lawrence units was approximately $1.69 per MMBtu, or $29.78 per ton. The average delivered cost of coal consumed in the Tecumseh units was approximately $1.66 per MMBtu, or $29.34 per ton.

Natural Gas

We use natural gas as a primary fuel at our Gordon Evans, Murray Gill, Neosho, Abilene, Hutchinson, Spring Creek and Emporia Energy Centers, at the State Line facility and in the gas turbine units at Tecumseh Energy Center. We can also use natural gas as a supplemental fuel in the coal-fired units at Lawrence and Tecumseh Energy Centers. During 2010, we consumed 21.3 million MMBtu of natural gas for a total cost of $109.0 million. Natural gas accounted for approximately 7% of our total MMBtu of fuel consumed during 2010 and approximately 21% of our total fuel expense. From time to time, we may enter into contracts, including the use of derivatives, in an effort to manage the overall cost of natural gas. For additional information about our exposure to commodity price risks, see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

We maintain natural gas transportation arrangements for Abilene and Hutchinson Energy Centers with Kansas Gas Service, a division of ONEOK, Inc. (ONEOK). Abilene Energy Center is covered under a standard tariff as a large industrial transportation customer while Hutchinson Energy Center is covered under a rate agreement that expires on April 30, 2011. We plan to renegotiate the agreement for Hutchinson Energy Center prior to its expiration. We meet a portion of our natural gas transportation requirements for Gordon Evans, Murray Gill, Lawrence, Tecumseh and Emporia Energy Centers through firm natural gas transportation capacity agreements with Southern Star Central Gas Pipeline (SSCGP). We meet all of the natural gas transportation requirements for the State Line facility through a firm natural gas transportation agreement with SSCGP. The firm transportation agreement that serves Gordon Evans and Murray Gill Energy Centers extends through April 1, 2020. The agreement for the State Line facility extends through April 9, 2017, while the agreement for Emporia Energy Center is in place until December 1, 2028, and is renewable for five-year terms thereafter. We meet all of the natural gas transportation requirements for Spring Creek Energy Center through an interruptible month-to-month natural gas transportation agreement with ONEOK Gas Transportation, LLC.

Diesel and Oil

Once started with natural gas, the steam units at our Gordon Evans, Murray Gill, Neosho and Hutchinson Energy Centers have the capability to burn No. 6 oil or natural gas. We may use No. 6 oil when natural gas is unavailable. During 2010, we did not use No. 6 oil.

We also use No. 2 diesel to start some of our coal generating stations, as a primary fuel in the Hutchinson No. 4 combustion turbine and in our diesel generators. We purchase No. 2 diesel in the spot market. We maintain quantities in inventory that we believe will allow us to facilitate economic dispatch of power, satisfy emergency requirements and protect against reduced availability of natural gas for limited periods.

During 2010, we consumed 0.2 million MMBtu of diesel at a total cost of $3.8 million. Diesel accounted for less than 1% of our total MMBtu of fuel consumed during 2010 and approximately 1% of our total fuel expense.

Nuclear Generation

General

Wolf Creek is a 1,158 MW nuclear power plant located near Burlington, Kansas. KGE owns a 47% interest in Wolf Creek, or 544 MW, which represents 8% of our total generating capacity. Wolf Creek's operating license is effective until 2045 and Wolf Creek Nuclear Operating Corporation operates the plant for its owners. The plant's owners pay operating costs equal to their respective ownership in Wolf Creek.

Fuel Supply

The owners of Wolf Creek have on hand or under contract all of the uranium and conversion services needed to operate through March 2014 and approximately 68% of the uranium and conversion services needed after that date through March 2020. The owners also have under contract 100% of the uranium enrichment and fabrication services required to operate Wolf Creek through March 2026. All such agreements have been entered into in the ordinary course of business.

Spent Nuclear Fuel and High-Level Radioactive Waste

Under the Nuclear Waste Policy Act of 1982, the DOE is responsible for the permanent disposal of spent nuclear fuel. Wolf Creek pays into a federal Nuclear Waste Fund administered by the DOE a quarterly fee for the future disposal of spent nuclear fuel. Our share of the fee, calculated as one-tenth of a cent for each kilowatt-hour of net nuclear generation delivered to customers, was $4.0 million in 2010, $3.7 million in 2009 and $3.5 million in 2008. We include these costs in fuel and purchased power expense on our consolidated statements of income.

In March 2010, the DOE filed a motion to withdraw its application with the Nuclear Regulatory Commission (NRC) to construct a national repository for the disposal of spent nuclear fuel and high-level radioactive waste at Yucca Mountain, Nevada, which would end the licensing process. An NRC board denied the DOE's motion to withdraw its application in June 2010 and the DOE appealed that decision to the full NRC in early July 2010. The NRC has not yet decided that appeal. The question of the DOE's legal authority to withdraw its license application also is pending in multiple lawsuits filed with a federal appellate court. Oral argument to the court is set for late March 2011. Wolf Creek has an on-site storage facility designed to hold all spent fuel generated at the plant through 2025 and believes it will be able to expand on-site storage as needed past 2025. We cannot predict when, or if, an alternative disposal site will be available to receive Wolf Creek's spent nuclear fuel and will continue to monitor this activity.

Low-Level Radioactive Waste

Wolf Creek disposes of most of its low-level radioactive waste at an existing third-party repository in Utah, which we expect will remain available to Wolf Creek. Wolf Creek also contracts with a waste processor to process, take title and store in another state most of the remainder of Wolf Creek's low-level radioactive waste. Should on-site waste storage be needed in the future, Wolf Creek has storage capacity on site adequate for about four years of plant operations.

Outages

Wolf Creek operates on an 18-month planned refueling and maintenance outage schedule. Wolf Creek did not have such an outage in 2010 and the next outage is scheduled for spring 2011. During outages at the plant, we meet our electric demand primarily with our other generating units and by purchasing power. As authorized by regulators, we defer and amortize to expense ratably over an 18-month operating cycle the incremental maintenance costs incurred for planned refueling and maintenance outages.

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

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

Nuclear Decommissioning

Nuclear decommissioning is a nuclear industry term for the permanent shutdown of a nuclear power plant and the removal of radioactive components in accordance with NRC requirements. The NRC will terminate a plant’s license and release the property for unrestricted use when a company has reduced the residual radioactivity of a nuclear plant to a level mandated by the NRC. The NRC requires companies with nuclear plants to prepare formal financial plans to fund nuclear decommissioning. These plans are designed so that sufficient funds required for nuclear decommissioning will be accumulated prior to the expiration of the license of the related nuclear power plant. Wolf Creek files a nuclear decommissioning site 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 including the estimated costs to decommission the plant. Phase two involves the review and approval by the KCC of a “funding schedule” prepared 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 decommissioning costs.

The KCC approved Wolf Creek’s most recent nuclear decommissioning site study in August 2009. Based on the study, our share of decommissioning costs, including decontamination, dismantling and site restoration, is estimated to be $279.0 million. This amount compares to the prior site study estimate of $243.3 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 and technologies as well as changes in costs for labor, materials and equipment.

We are allowed to recover nuclear decommissioning costs in our prices over a period equal to the operating license of Wolf Creek, which is through 2045. The NRC requires that funds sufficient to meet nuclear decommissioning obligations be held in trust. We believe that the KCC approved funding level will also be sufficient to meet the NRC requirement. Our consolidated financial results would be materially adversely affected if we were not allowed to recover in our prices the full amount of the funding requirement.

We recovered in our prices and deposited in an external trust fund for nuclear decommissioning approximately $3.1 million in 2010 and $2.9 million in both 2009 and 2008. We record our investment in the nuclear decommissioning trust (NDT) fund at fair value, which approximated $127.0 million as of December 31, 2010, and $112.3 million as of December 31, 2009.

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Wind Generation

As discussed under “Environmental Matters – Renewable Energy Standard” below, the State of Kansas has enacted legislation mandating that more energy be derived from renewable sources. For us, wind has been the primary source of renewable energy. During 2010, our wind generation facilities produced 453,049 megawatt hours (MWh) of electricity and we purchased an additional 423,673 MWh of renewable energy through purchase power agreements. On December 14, 2010, we announced that we reached two separate agreements with third parties, subject to regulatory approval, to purchase under 20-year supply contracts the renewable energy produced from approximately 370 MW of wind generation beginning in late 2012.

Other Fuel Matters

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

	2010	2009	2008
Per MMBtu:			
Nuclear	$ 0.63	$ 0.47	$ 0.44
Coal	1.56	1.51	1.42
Natural gas	5.12	4.22	7.77
Diesel/oil	15.76	15.58	21.01
Per MWh Generation:			
Nuclear	$ 6.50	$ 4.87	$ 4.57
Coal	17.45	16.79	15.75
Natural gas/diesel/oil	56.37	48.52	79.50
All generating stations	18.37	17.18	18.99

Our wind production has no fuel costs and is therefore excluded from the table above.

Purchased Power

We purchase electricity in addition to generating it. Factors that cause us to make such purchases include contractual arrangements, planned and unscheduled outages at our generating plants, prices for wholesale energy compared to our own costs of production, weather conditions and other factors. Transmission constraints may limit our ability to bring purchased electricity into our control area, potentially requiring us to curtail or interrupt our customers as permitted by our tariffs. In 2010, purchased power comprised approximately 14% of our total fuel and purchased power expense. The weighted average cost of purchased power per MWh was $36.23 in 2010, $35.62 in 2009 and $58.96 in 2008.

Energy Marketing Activities

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

Competition and Deregulation

The Federal Energy Regulatory Commission (FERC) requires owners of regulated transmission assets to allow third parties nondiscriminatory access to their transmission systems. FERC also requires us to provide transmission services to others on the same basis as we use those assets ourselves. Furthermore, FERC issued an order encouraging the formation of RTOs under which transmission service is aggregated and coordinated across broad regions to better enable competitive wholesale power markets.

Regional Transmission Organization

We are a member of the Southwest Power Pool (SPP), the RTO in our region. The SPP coordinates the operation of our transmission system within an interconnected transmission system that covers all or portions of nine states. The SPP collects revenues for the use of each transmission owner's transmission system. Transmission customers transmit power purchased and generated for sale or bought for resale in the wholesale market throughout the entire SPP system. Transmission capacity is sold on a first come/first served non-discriminatory basis. All transmission customers are charged rates applicable to the transmission system in the zone where energy is delivered, including transmission customers that may sell power inside our certificated service territory. The SPP then distributes as revenue to transmission owners, less an administrative charge, the amounts it collects from transmission users.

Real-Time Energy Imbalance Market

The SPP utilizes a real-time energy imbalance market to accommodate financial settlement of energy imbalances within the SPP region. The objective of the real-time market is to permit an efficient balancing of energy production and consumption through the use of a least-cost economic dispatch system. It also provides a ready market for the purchase and sale of electricity to balance production with demand. We participate in this market.

Regulation and Our Prices

Kansas law gives the KCC general regulatory authority over our prices, extensions and abandonments of service and facilities, the classification of accounts, the issuance of some securities and various other matters. We are also subject to the jurisdiction of FERC, which has authority over wholesale sales of electricity, the transmission of electric power and the issuance of some securities. We are subject to the jurisdiction of the NRC for nuclear plant operations and safety. Regulatory authorities have established various methods permitting adjustments to our prices for the recovery of certain costs. For portions of our cost of service, regulators allow us to adjust our prices periodically by formulae, which reduce the time between making expenditures and reflecting them in the prices we charge customers. However, for the remaining portions of our cost of service, we must file a formal rate case, which lengthens the period of time between making and recovering expenditures.

KCC Proceedings

In February 2011, we filed an application with the KCC to adjust our prices to include updated transmission costs as reflected in our transmission formula rate discussed below. If approved, we estimate that the new prices will increase our annual retail revenues by $14.6 million. We expect the KCC to issue an order on our request in March 2011.

On January 27, 2011, the KCC opened a docket seeking additional information from us and KCPL regarding planned environmental upgrades. The docket is focused on determining how required environmental upgrades may affect generating capabilities of the two companies and establishing criteria to be used when evaluating retrofit, decommission or replacement decisions. We are not able to determine the timing or outcome of this docket.

On October 29, 2010, the KCC issued an order, effective November 2010, allowing us to recover in our prices $5.8 million of previously deferred amounts associated with various energy efficiency programs.

On June 11, 2010, the KCC issued a final order approving an adjustment to our prices that we made earlier in 2010. The adjustment included updated transmission costs as reflected in our transmission formula rate discussed below. The new prices were effective March 16, 2010, and are expected to increase our annual retail revenues by $6.4 million.

On May 25, 2010, the KCC issued an order allowing us to adjust our prices to include costs associated with environmental investments made in 2009. The new prices were effective June 1, 2010, and are expected to increase our annual retail revenues by $13.8 million.

On January 27, 2010, the KCC issued an order allowing us to adjust our prices to include costs associated with investments in natural gas and wind generation facilities. The new prices were effective February 2010 and are expected to increase our annual retail revenues by $17.1 million.

FERC Proceedings

On October 15, 2010, we posted our updated transmission formula rate which includes projected 2011 transmission capital expenditures and operating costs. The updated rate was effective January 1, 2011, and is expected to increase our annual transmission revenues by $15.9 million.

Our transmission formula rate that includes projected 2010 transmission capital expenditures and operating costs became effective January 1, 2010, and was expected to increase our annual transmission revenues by $16.8 million. The transmission formula rate provides the basis for our annual request with the KCC to adjust our retail prices to include updated transmission costs as noted above.

On January 12, 2010, FERC issued an order accepting our request to implement a cost-based formula rate for electricity sales to wholesale customers. The use of a cost-based formula rate allows us to annually adjust our prices to reflect changes in our cost of service. The cost-based formula rate was effective December 1, 2009.

Environmental Matters

General

We are subject to various federal, state and local environmental laws and regulations. Environmental laws and regulations affecting power plants are overlapping, complex, subject to changes in interpretation and implementation, and have become more stringent over time. These laws and regulations relate primarily to discharges into the air, air quality, discharges of effluents into water, the use of water, and the handling, disposal and clean-up of hazardous and non-hazardous substances and wastes. These laws and regulations require a lengthy and complex process for obtaining licenses, permits and approvals from governmental agencies for our new, existing or modified facilities. If we fail to comply with such laws, regulations and permits, or fail to obtain and maintain necessary permits, we could be fined or otherwise sanctioned by regulators, and such fines or sanctions may not be recoverable in our prices. We have incurred and will continue to incur significant capital and other expenditures to comply with environmental laws and regulations. We are permitted to recover certain of these costs through the environmental cost recovery rider (ECRR), which allows for the more timely inclusion in retail prices the costs of capital expenditures associated with environmental improvements, including those required by the Federal Clean Air Act. However, there can be no assurance that the costs to comply with existing or future environmental laws and regulations will not have a material adverse effect on our consolidated financial results. Certain key environmental issues, laws and regulations facing us are described further below.

Air Emissions

We must comply with the Federal 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, nitrogen oxides (NOx) and mercury. In addition, we must comply with the provisions of the Federal Clean Air Act Amendments of 1990 that require reductions in SO_2 and NOx.

Emissions from our generating facilities, including particulate matter, SO_2 and NOx, have been determined by regulation to reduce visibility by causing or contributing to regional haze. Under federal laws, such as the Clean Air Visibility Rule, and pursuant to an agreement with the Kansas Department of Health and Environment (KDHE), we are required to install and maintain controls to reduce emissions found to cause or contribute to regional haze.

Sulfur Dioxide

Through the combustion of fossil fuels at our generating facilities, we emit SO_2 and NOx. Federal and state laws and regulations limit the amount of SO_2 that we can emit. If we exceed these limits we could be subject to fines and penalties. In order to meet KDHE SO_2 regulations applicable to our generating facilities, we use low-sulfur coal and natural gas and have equipped some of our generating facilities with equipment to control such emissions.

We are subject to the SO_2 allowance and trading program under the Federal Clean Air Act. Under this program, the Environmental Protection Agency (EPA) allocates annual SO_2 emissions allowances to emitting units subject to the program. Each unit must have enough allowances to cover its SO_2 emissions for that year. Allowances are tradable so that operators of affected units that are anticipated to emit SO_2 in excess of their allowances may purchase additional allowances from others. In 2010, we had SO_2 allowances adequate to meet planned generation and we expect to have enough in 2011. In the future if we need to purchase additional air emission allowances our operating costs would increase. We recover, and expect to continue to recover, the cost of such allowances through the RECA.

Clean Air Transport Rule

In July 2010, the EPA proposed the Clean Air Transport Rule (CATR), which would require the District of Columbia and 31 states, including Kansas, to issue regulations and develop a plan by which power plants in their respective jurisdictions will further reduce emissions of SO_2 and NOx. Reductions would be required beginning in 2012, with further reductions likely to be required in 2014. The EPA expects CATR to be finalized in the spring of 2011, but it is unclear when the states would issue implementing regulations. There are a number of uncertainties relating to this proposed rule, including whether it will be finalized and how the states will implement the requirements. As a result, we cannot determine the impact this rule will have on our operations or consolidated financial results, but it could be material.

National Ambient Air Quality Standards

Under the Federal Clean Air Act, the EPA sets National Ambient Air Quality Standards (NAAQS) for six criteria pollutants considered harmful to public health and the environment, including particulate matter, NOx, ozone and SO_2, which result from coal combustion. Areas meeting the NAAQS are designated attainment areas while those that do not meet the NAAQS are considered nonattainment areas. In 2009, KDHE proposed to designate portions of the Kansas City area nonattainment for the 8-hour ozone standard, which has the potential to impact our operations. Each state must develop a plan to bring nonattainment areas into compliance with the NAAQS. NAAQS must be reviewed by the EPA at five-year intervals.

In 2010, the EPA strengthened the NAAQS for both NOx and SO_2. We are currently evaluating what impact this could have on our operations. If we are required to install additional equipment to control emissions at our facilities, the revised NAAQS could have a material impact on our operations and consolidated financial results.

Particulate matter, principally ash, is a byproduct of coal combustion. In 2011, the particulate matter NAAQS are scheduled for their required five-year review, at which time the EPA could issue more stringent standards. We cannot at this time predict the impact of any new standards on our operations or consolidated financial results, but it could be material.

The EPA is currently in the process of revising the NAAQS for ozone. The EPA has requested additional time to finalize the ozone NAAQS, which are expected to be issued in July 2011. If these revisions result in more stringent standards, we could be required to place additional NOx pollution control measures on our facilities. Without knowing the new ozone standards, we cannot determine the impact they may have on our operations or consolidated financial results, but it could be material.

Mercury Emissions

Coal contains mercury. When we combust coal at our generating facilities, we emit mercury into the air. The federal Clean Air Mercury Rule (CAMR) permanently caps and reduces nationwide mercury emissions from new and existing coal-fired power plants. In 2008, the U.S. Court of Appeals for the District of Columbia Circuit vacated CAMR. In lieu of CAMR, the EPA has announced that it intends to propose air toxics standards under the Clean Air Act, including mercury standards, for coal and oil-fired electric generating units by March 2011 and to finalize a rule by November 2011. Without knowing what the rule will require, we cannot estimate the impact to us. However, our costs to comply with future mercury emission requirements could have a material impact on our operations and consolidated financial results.

Carbon Dioxide and Greenhouse Gases

One byproduct of burning coal and other fossil fuels is the emission of carbon dioxide (CO_2), which is believed by many to contribute to climate change. Legislators, including the U.S. Congress, have at times considered the passage of laws to limit the emission of CO_2 and other gases referred to as greenhouse gases (GHGs). In 2009 the U.S. House of Representatives passed, and the U.S. Senate considered but did not pass, legislation that proposed, among other things, a nationwide cap on CO_2 and other GHG emissions and a requirement that major sources, including coal-fueled power plants, obtain emission allowances to meet that cap. It is possible that federal legislation related to GHG emissions will be considered by legislators in the future. The EPA has also proposed using the Federal Clear Air Act to limit CO_2 and other GHG emissions, and other measures are being imposed or offered by individual states, municipalities and regional agreements, such as the Midwestern Greenhouse Gas Reduction Accord, with the goal of reducing GHG emissions.

Under EPA regulations finalized in May 2010, known as the tailoring rule, the EPA began regulating GHG emissions from certain stationary sources in January 2011. The regulations are being implemented pursuant to two Federal Clear Air Act programs: the Title V Operating Permit program and the program requiring a permit if undergoing construction or major modifications, which is referred to as the Prevention of Significant Deterioration program (PSD). Obligations relating to Title V permits will include recordkeeping and monitoring requirements. With respect to PSD permits, projects that cause a significant increase in GHG emissions (currently defined to be more than 75,000 tons or more per year or 100,000 tons or more per year, depending on various factors), will be required to implement best available control technology (BACT). The EPA has issued guidance on what BACT entails for the control of GHGs and individual states are now required to determine what controls are required for facilities within their jurisdiction on a case-by-case basis. We cannot at this time determine the impact of these new regulations on our operations and consolidated financial results, but we believe the cost of compliance with new regulations could be material.

In December 2010, the EPA announced it will be proposing GHG New Source Performance Standard (NSPS) rules for power plants and refineries. The rules for power plants will be proposed by July 2011, and finalized by May 2012. These rules would apply to new and existing facilities, including ours. Because these regulations have yet to be proposed, we cannot predict the impact they may have on our generating facilities or consolidated financial results, but it could be material.

In the absence of further federal legislation or regulation, certain states, regions and local authorities have developed their own GHG initiatives. In November 2007, the governors of Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Ohio, South Dakota and Wisconsin and the Premier of Manitoba signed the Midwestern Greenhouse Gas Reduction Accord to develop and implement steps to reduce GHG emissions. In May 2010, the Midwestern Greenhouse Gas Reduction Accord Advisory Group finalized their recommendations for emissions reductions targets and targeted sectors for GHG reductions in their jurisdiction. These include a recommended reduction in GHG emissions of 20% below 2005 emissions levels by 2020. These recommendations are from the advisory committee only and have not been endorsed by the respective states or provinces. If Kansas were to implement the recommended or any other targets, the impact on our operations and consolidated financial results could be material.

Wastewater Effluent

Some water used in our operations is discharged as wastewater effluent. This wastewater may contain heavy metals and other substances deemed to be pollutants. The EPA plans to propose revisions to the rules governing such wastewater effluent from coal-fired power plants by July 2012 with final action on the proposed rules expected to occur by January 2014. Although we cannot at this time determine the impact of any new regulations, more stringent regulations could have a material impact on our operations and consolidated financial results.

Regulation of Coal Combustion Byproducts

In the course of operating our coal generation plants, we produce coal combustion byproducts (CCBs), including fly ash and bottom ash, which we must handle, dispose, recycle or process. We recycle approximately 45% of our fly ash and bottom ash production, principally by selling to the aggregate industry. This is referred to as "beneficial use." On June 21, 2010, the EPA published in the Federal Register a proposed rule to regulate CCBs under the Resource Conservation and Recovery Act (RCRA). The proposed rule provides two possible options for CCB regulation, both of which technically would allow for the continued beneficial use of CCBs, but we believe might actually curtail or impair beneficial use to the extent we are able to recycle it today. The first option would subject CCBs to regulation as special waste under Subtitle C of RCRA. The second option would regulate CCBs as non-hazardous solid waste under Subtitle D of RCRA and impose national criteria applicable to CCBs disposed of in landfills and surface impoundments. While we cannot at this time estimate the impact and cost associated with future regulations of CCBs, we believe the impact on our operations and consolidated financial results could be material.

Agreement with Regulators

We entered into an agreement with the EPA and Department of Justice (DOJ) to resolve alleged violations of the Federal Clean Air Act at JEC. The terms of the agreement require us to install additional equipment as well as perform environmental mitigation projects to further reduce air emissions. See "—EPA Lawsuit" below for further information regarding the terms of the agreement.

Renewable Energy Standard

In May 2009, Kansas enacted legislation that mandates, among other requirements, that more energy be derived from renewable sources. In years 2011 through 2015 net renewable generation capacity must be 10% of the average peak demand for the three prior years, subject to limited exceptions. This requirement increases to 15% for years 2016 through 2019 and 20% for 2020 and thereafter. We have worked with third parties to develop approximately 300 MW of qualifying wind generation facilities, which together with the use of renewable energy credits, we expect to meet the 2011 requirement. On December 14, 2010, we announced that we reached two separate agreements with third parties, subject to regulatory approval, to purchase under 20-year supply contracts the renewable energy produced from approximately 370 MW of wind generation beginning in late 2012. We expect these agreements, along with our prior development of wind generation facilities, will satisfy our net renewable generation requirement through 2015 and contribute toward meeting the increased requirement beginning in 2016.

Environmental Costs

We will continue to make significant capital expenditures and incur operating expenses at our power plants to reduce regulated emissions. The amount of these expenditures could change materially depending on the timing and nature of required investments, the specific outcomes resulting from interpretation of existing regulations, new regulations, legislation and the manner in which we operate 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. Additionally, our ability to access capital markets and the availability of materials, equipment and contractors may affect the timing and amount of these capital investments. The ECRR allows for the more timely inclusion in retail prices the costs of capital expenditures associated with environmental improvements, including those required by the Federal Clean Air Act.

A recent order of the KCC indicated that it may be more appropriate to recover environmental costs at La Cygne through the filing of a general rate case as opposed to the ECRR. This could increase the time between making these investments and having them reflected in the prices we charge our customers, as well as the amount we charge our customers. Estimated capital expenditures associated with environmental improvements for 2011-2013 appear in the following table. We prepare these estimates for planning purposes and revise them from time to time.

	La Cygne	Total
Year	(In Thousands)	
2011	$ 63,000	$244,100
2012	171,000	371,100
2013	195,100	349,400
Total	$429,100	$964,600

In addition to the capital investment, in the event we install new equipment, such equipment may cause us to incur significant increases in annual operating and maintenance expense and may reduce the net production, reliability and availability of the plants. In order to change our prices to recognize increased operating and maintenance costs, we must file a general rate case with the KCC.

Manufactured Gas Sites

We have been identified as being partially responsible for remediating a number of former manufactured gas sites located in Kansas. We and the KDHE entered into a consent agreement governing all future work at these sites. Under terms of the consent agreement, we agreed to investigate and, if necessary, remediate these sites. Pursuant to an environmental indemnity agreement with ONEOK, the current owner of some of the sites, ONEOK assumed total liability for remediation of seven sites and we share liability for remediation with ONEOK for five sites. Our total liability for the five shared sites is capped at $3.8 million.

Our environmental liability for remediation of former manufactured gas sites in Missouri associated with assets we divested many years ago had been limited to $7.5 million by the terms of an environmental indemnity agreement with the purchaser of those assets. In June 2010, the purchaser agreed to reduce our maximum liability to $2.5 million, which reflects our share of the purchaser’s expected remediation costs. We have settled this liability.

EPA Lawsuit

Under Section 114(a) of the Federal Clean Air Act, 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 NSPS. 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.

In January 2004, the EPA notified us that certain projects completed at JEC violated certain requirements of the New Source Review program. In February 2009, the DOJ, on behalf of the EPA, filed a lawsuit against us in U.S. District Court in the District of Kansas asserting substantially the same claims. On January 25, 2010, we announced a settlement of the lawsuit. The settlement was filed with the court, seeking its approval, and on March 26, 2010, the court entered an order approving the settlement. The settlement requires that we install a selective catalytic reduction (SCR) on one of the three JEC coal units by the end of 2014. We estimate the cost of this to be approximately $240.0 million. This amount could change materially depending on final engineering and design. Depending on the NOx emission reductions attained by the single SCR and attainable through the installation of other controls on the other two JEC coal units, we may have to install an SCR on another JEC unit by the end of 2016, if needed to meet NOx reduction targets. Recovery of costs to install these systems is subject to the approval of our regulators. We believe these costs are appropriate for inclusion in the prices we are allowed to charge our customers. We will also invest $5.0 million over six years in environmental mitigation projects that we will own. In 2009, we recorded as part of the settlement $1.0 million for environmental mitigation projects that will be owned by a qualifying third party and a $3.0 million civil penalty.

SEASONALITY

As a summer peaking utility, our revenues are seasonal. The third quarter typically accounts for our greatest revenues. Our electricity sales are affected by weather conditions, the economy of our service territory and other factors affecting customers' demand for electricity.

EMPLOYEES

As of February 15, 2011, we had 2,409 employees. Our current contract with Local 304 and Local 1523 of the International Brotherhood of Electrical Workers extends through June 30, 2011. We expect to negotiate a new contract with the Electrical Workers. The contract covered 1,326 employees as of February 15, 2011.

ACCESS TO COMPANY INFORMATION

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

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EXECUTIVE OFFICERS OF THE COMPANY

Name	Age	Present Office	Other Offices or Positions Held During the Past Five Years
William B. Moore	58	Director, President and Chief Executive Officer (since July 2007)	**Westar Energy, Inc.** President and Chief Operating Officer (March 2006 to June 2007) Executive Vice President and Chief Operating Officer (December 2002 to March 2006)
James J. Ludwig	52	Executive Vice President, Public Affairs and Consumer Services (since July 2007)	**Westar Energy, Inc.** Vice President, Regulatory and Public Affairs (March 2006 to June 2007) Vice President, Public Affairs (January 2003 to March 2006)
Mark A. Ruelle	49	Executive Vice President and Chief Financial Officer (since January 2003)	
Douglas R. Sterbenz	47	Executive Vice President and Chief Operating Officer (since July 2007)	**Westar Energy, Inc.** Executive Vice President, Generation and Marketing (March 2006 to June 2007) Senior Vice President, Generation and Marketing (October 2001 to March 2006)
Jeffrey L. Beasley	52	Vice President, Corporate Compliance and Internal Audit (since September 2007)	**Westar Energy, Inc.** Executive Director, Corporate Compliance and Internal Audit (September 2006 to September 2007) Director, Corporate Finance (March 2005 to September 2006)
Larry D. Irick	54	Vice President, General Counsel and Corporate Secretary (since February 2003)	
Michael Lennen	65	Vice President, Regulatory Affairs (since July 2007)	**Morris, Laing, Evans, Brock & Kennedy, Chartered** Partner (January 1990 to July 2007)
Lee Wages	62	Vice President, Controller (since December 2001)	

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

ITEM 1A. RISK FACTORS

We operate in market and regulatory environments that involve significant risks, many of which are beyond our control. In addition to other information in this Form 10-K, including “Item 1. Business” and “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations,” and in other documents we file with the SEC from time to time, the following factors may affect our results of operations and cash flows and the market prices of our publicly traded securities. These factors may cause results to differ materially from those expressed in any forward-looking statements made by us or on our behalf. The factors listed below are not intended to be an exhaustive discussion of all such risks, and the statements below must be read together with factors discussed elsewhere in this document and in our other filings with the SEC.

Weather conditions, including mild and severe weather, may adversely impact our consolidated financial results.

Weather conditions directly influence the demand for electricity. Our customers use electricity for heating in winter months and cooling in summer months. Because of air conditioning demand, typically we produce our highest revenues in the third quarter. Milder temperatures reduce demand for electricity and have a corresponding affect on our revenues. Unusually mild weather in the future could adversely affect our consolidated financial results.

In addition, severe weather conditions can produce storms that can inflict extensive damage to our equipment and facilities that can require us to incur additional operating and maintenance expense and additional capital expenditures. Our prices may not always be adjusted timely and adequately to reflect these higher costs. Additionally, because many of our power plants use water for cooling, severe drought conditions could result in limited power production.

Our prices are subject to regulatory review and may not prove adequate.

We must obtain from state and federal regulators the authority to establish terms and prices for our services. The KCC and, for most of our wholesale customers, FERC, use a cost-of-service approach that takes into account operating expenses, fixed obligations and recovery of and return on capital investments. Using this approach, the KCC and FERC set prices at levels calculated to recover these costs and a permitted return on investment. Except for wholesale transactions for which the price is not so regulated, and except to the extent the KCC and FERC permit us to modify our prices by using approved formulae, our prices generally remain fixed until changed following a rate review. Further, the adjustments and formulae may be modified, limited or eliminated by regulatory or legislative actions. We may apply to change our prices or intervening parties may request that our prices be reviewed for possible adjustment.

Rate proceedings through which our prices and terms of service are determined typically involve numerous parties including electricity consumers, consumer advocates and governmental entities, some of whom frequently take positions adverse to us. The decision making process used in these proceedings may or may not be subject to statutory timelines, and in any event regulators’ decisions may be appealed to the courts by us or other parties to the proceedings. These factors may lead to uncertainty and delays in implementing changes to our prices or terms of service. There can be no assurance that our regulators will find all of our costs to have been prudently incurred. A finding that costs have been imprudently incurred can lead to disallowance of recovery for those costs. The prices approved by the applicable regulatory body may not be sufficient for us to recover our costs and to provide for an adequate return on and of capital investments.

We cannot predict the outcome of any rate review or the actions of our regulators. The outcome of rate proceedings, or delays in implementation of new prices regarding costs that we have already incurred, could have a significant affect on our ability to recover costs and could have a material adverse affect on our consolidated financial results.

Significant decisions about capital investments are based on forecasts of long-term demand for energy incorporating assumptions about multiple, uncertain factors. Our actual experience may differ significantly from our assumptions, which may adversely impact our consolidated financial results.

We attempt to forecast demand to determine the timing and adequacy of our energy and energy delivery resources. Long-term forecasts involve risks because they rely on assumptions we make concerning uncertain factors including weather, technological change, economic conditions, regulatory requirements, social pressures and the responsiveness of customers' electricity demand to conservation measures and prices. Actual future demand depends on these and other factors and may vary materially from our forecasts. If our actual experience varies significantly from our forecasts, our consolidated financial results may be adversely affected.

Our ability to fund our capital expenditures and meet our working capital and liquidity needs may be limited by conditions in the bank and capital markets or by our credit ratings or the market price of Westar Energy's common stock.

To fund our capital expenditures and for working capital and liquidity, we rely on access to capital markets and to short-term credit. Disruption in capital markets, deterioration in the financial condition of the financial institutions on which we rely, any credit rating downgrade or any decrease in the market price of Westar Energy's common stock may make capital more difficult and costly for us to obtain, may restrict liquidity available to us, may require us to defer or limit capital investments or impact operations, or may reduce the value of our financial assets. These and other related affects may have an adverse impact on our business and consolidated financial results, including our ability to pay dividends and to make investments or undertake programs necessary to meet regulatory mandates and customer demand.

Our planned capital investment for the next few years is large in relation to our size, subjecting us to significant risks.

Our anticipated capital expenditures for 2011 through 2013 are approximately $2.4 billion. In addition to risks discussed above associated with recovering capital investments through our prices, and risks associated with our reliance on the capital markets and short-term credit to fund those investments, our capital expenditure program poses risks, including, but not necessarily limited to:

- shortages, disruption in the delivery and inconsistent quality of equipment, materials and labor;
- contractor or supplier non-performance;
- delays in or failure to receive necessary permits, approvals and other regulatory authorizations;
- impacts of new and existing laws and regulations, including environmental laws, regulations and permit requirements;
- adverse weather;
- unforeseen engineering problems or changes in project design or scope;
- environmental and geological conditions; and
- unanticipated cost increases with respect to labor or materials, including basic commodities needed for our infrastructure such as steel, copper and aluminum.

These and other factors, or any combination of them, could cause us to defer or limit our capital expenditure program and could adversely impact our consolidated financial results.

Capital market conditions can cause fluctuations in the values of assets set aside for employee benefit obligations and the Wolf Creek NDT and may increase our funding requirements related to these obligations.

We have significant future financial obligations with respect to employee benefit obligations and the Wolf Creek NDT. The value of the assets needed to meet those obligations are subject to market fluctuations and will yield uncertain returns, which may fall below our expectations, upon which we plan to meet our obligations. Additionally, changes in interest rates affect the value of future liabilities. While the KCC has recently allowed us to implement a regulatory accounting mechanism to track certain of our employee benefit plan expenses, this mechanism does not allow us to make automatic price adjustments. Only in future rate proceedings may we be allowed to adjust our prices to reflect changes in our funding requirements for these benefit plans. Further, the tracking mechanism for these benefit plan expenses is part of our overall rate structure, and as such it is subject to KCC review and may be modified, limited or eliminated in the future. If these assets are not managed successfully, our consolidated financial results could be adversely affected.

Adverse economic conditions could adversely impact our operations and our consolidated financial results.

Our operations are affected by economic conditions. Adverse general economic conditions including a prolonged recession or capital market disruptions may:

- reduce demand for our service;
- increase delinquencies or non-payment by customers;
- adversely impact the financial condition of suppliers, which may in turn limit our access to inventory or capital equipment or increase our costs;
- increase deductibles and premiums and result in more restrictive policy terms under insurance policies regarding risks we typically insure against, or make insurance claims more difficult to collect;
- result in lower worldwide demand for coal, oil and natural gas, which may decrease fossil fuel prices and put downward pressure on electricity prices; and
- reduce the credit available to our energy trading counterparties and correspondingly reduce our energy trading activity or increase our exposure to counterparty default.

Any of these events, and others we may not be able to identify, could have an adverse impact on our consolidated financial results.

Deliveries of fuel for our plants may be interrupted or slowed, which may adversely impact our consolidated financial results.

We purchase fuel, including coal, natural gas and uranium, from a number of suppliers. Disruption in the delivery of fuel or environmental regulations affecting any of our fuel suppliers could limit our ability to operate our facilities. In addition, the markets for coal, natural gas and uranium are subject to price fluctuations, availability restrictions and counterparty default. It is not possible to predict the cost or availability of these commodities. Such costs, if not recovered in our prices, could have a material adverse affect on our consolidated financial results.

We are subject to complex governmental regulation that could require us to incur additional expenses or subject us to penalties.

Our operations are subject to extensive regulation and require numerous permits, approvals and certificates from various governmental agencies. New laws or regulations, the revision or reinterpretation of existing laws or regulations, or penalties imposed for non-compliance with existing laws or regulations may require us to incur additional expenses, which could have a material adverse affect on our consolidated financial results.

We could be subject to penalties as a result of mandatory reliability standards, which could adversely affect our consolidated financial results.

As a result of the Energy Policy Act of 2005, owners and operators of the bulk power transmission system, including Westar Energy and KGE, are subject to mandatory reliability standards promulgated by the North American Electric Reliability Corporation and enforced by FERC. If we are found not to be in compliance with the mandatory reliability standards, we could be subject to sanctions, including substantial monetary penalties, which we may not be able to recover in the prices we charge our customers. This could have a material adverse affect on our consolidated financial results.

Our costs of compliance with environmental laws are significant, and the future cost of compliance with environmental laws could adversely affect our consolidated financial results.

We are subject to extensive federal, state and local environmental statutes, rules and regulations relating to discharges into the air, air quality, discharges of effluents into water, water quality, the use of water, the handling, disposal and clean up of hazardous and non-hazardous substances and wastes, natural resources, and health and safety. Compliance with these legal requirements, which change frequently and often become more restrictive, requires us to commit significant capital and operating resources toward permitting, emission fees, environmental monitoring, installation and operation of pollution control equipment and purchases of air emission allowances and/or offsets.

Costs of compliance with environmental regulations, if not recovered in our prices, could adversely affect our consolidated financial results, especially if emission and/or discharge limits are tightened, more extensive permitting requirements are imposed, additional substances become regulated and the number and types of assets we operate increases. We cannot estimate our compliance costs with certainty due to our inability to predict the requirements and timing of implementation of environmental rules or regulations.

We may be subject to legislative and regulatory responses to concerns about climate change, which could require us to incur substantial costs.

We emit large amounts of CO_2 and other gases through the operation of our power plants. Federal legislation has been in the past and may in the future be introduced in Congress to regulate the emission of GHGs and numerous states have adopted programs to stabilize or reduce GHG emissions.

Additionally, the EPA is proceeding with regulation of GHGs under the Clean Air Act. Under EPA regulations finalized in May 2010, the EPA began regulating GHG emissions from certain stationary sources, such as power plants, in January 2011. Under the regulations, any source that emits at least 75,000 tons per year of GHGs will be required to have a Title V operating permit under the Clean Air Act. Sources that already have a Title V permit would have GHG provisions added to their permit upon renewal. Additionally, PSD permits for new major sources of GHG emissions and GHG sources that undergo major modifications on or after January 2, 2011, will require the implementation of the BACT for the control of GHG emissions. The EPA has issued guidance on what BACT entails for the control of GHGs and individual states are now required to determine what controls are required for facilities within their jurisdiction on a case-by-case basis. These regulations could have a material impact on our operations or require us to incur substantial costs.

Furthermore, in December 2010, the EPA announced it will be proposing GHG NSPS rules for power plants and refineries. The rules for power plants will be proposed by July 2011, and finalized by May 2012. These rules would apply to new and existing facilities, including ours. Because these regulations have yet to be proposed, we cannot predict the impact they may have on our generating facilities or consolidated financial results, but it could be material.

Our cost of compliance with future federal regulations relating to the disposal of CCBs could require us to incur substantial costs.

In the course of operations, many of our facilities generate CCBs, including fly ash and bottom ash, requiring disposal or processing. On June 21, 2010, the EPA published in the Federal Register a proposed rule to regulate CCBs under RCRA. The proposed rule provides two possible options for CCB regulation, one of which would subject CCBs to increased regulation as special waste under Subtitle C of RCRA. While the impact and cost associated with the potential future regulation of CCBs cannot be established until such regulations are finalized, such regulations could have a material impact on our operations and/or require us to incur substantial costs.

Our risk management policies cannot eliminate price volatility and counterparty credit risks associated with our energy marketing activities.

We engage in energy marketing transactions with the goal of managing our commodity price risk, enhancing system reliability and increasing profits. We operate in active wholesale markets that expose us to price volatility for electricity and fuel and other commodities. The prices we use to value these transactions reflect our best estimates of the fair value of these contracts. Results actually achieved from these activities could vary materially from intended results and could cause significant earnings variability. In addition, we are exposed to credit risks of our counterparties and the risk that one or more counterparties may fail to perform their obligations to make payments or deliveries. Defaults by suppliers or other counterparties may adversely affect our consolidated financial results.

We attempt to manage our exposure to price volatility and counterparty credit risk through application of established risk limits and risk management procedures. These risk limits and risk management procedures may not work as planned and cannot eliminate all risks associated with these activities.

We are exposed to various risks associated with the ownership and operation of Wolf Creek, any of which could adversely impact our consolidated financial results.

Through KGE’s ownership interest in Wolf Creek, we are subject to the risks of nuclear generation, which include:

- the risks associated with storing, handling and disposing of radioactive materials and the current lack of a long-term disposal solution for radioactive materials;

- limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with nuclear operations;

- uncertainties with respect to the technological and financial aspects of decommissioning Wolf Creek at the end of its life; and

- costs of measures associated with public safety.

The NRC has authority to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has authority to impose fines or shut down a unit, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. Revised safety requirements enacted by the NRC could necessitate substantial capital expenditures at Wolf Creek. In addition, the Institute of Nuclear Power Operations (INPO) reviews Wolf Creek operations and facilities. Compliance with INPO recommendations could result in substantial capital expenditures or a substantial increase in operating expenses at Wolf Creek being passed through to KGE.

If an incident did occur at Wolf Creek, it could have a material adverse affect on our consolidated financial results. Furthermore, the non-compliance of other nuclear facilities operators with applicable regulations or the occurrence of a serious nuclear incident at other facilities could result in increased regulation of the industry as a whole, which could in turn increase Wolf Creek’s compliance costs and impact our consolidated financial results.

In addition, in the event of an extended or unscheduled outage at Wolf Creek, we would be required to generate power from more costly generating units, purchase power in the open market to replace the power normally produced at Wolf Creek and have less power available for sale into the wholesale markets. If we were unable to recover these costs from customers, such events would likely have an adverse impact on our consolidated financial results.

Events could occur that would change the accounting principles for regulated utilities currently applicable to our business, which would have an adverse impact on our consolidated financial results.

We currently apply accounting principles that are unique to regulated entities. As of December 31, 2010, we had recorded regulatory assets of $861.1 million and regulatory liabilities of $164.0 million. In the event we determined that we could no longer apply these principles, either as: (i) a result of the establishment of retail competition in our service territory; (ii) a change in the regulatory approach for setting our prices from cost-based ratemaking to another form of ratemaking; (iii) a result of other regulatory actions that restrict cost recovery to a level insufficient to recover costs; or (iv) a change from current generally accepted accounting principles (GAAP) to another set of standards that does not recognize regulatory assets and/or liabilities, then we may be required to record a charge against income in an amount up to the remaining unamortized regulatory assets. Such an action would materially reduce our shareholders' equity. We review these criteria to ensure that the continuing application of these principles is appropriate each reporting period. Based upon our most current evaluation of the various factors that are expected to impact future cost recovery, we believe that our regulatory assets are probable of recovery.

Equipment failures and other events beyond our control may cause extended or unplanned plant outages, which may adversely impact our consolidated financial results.

The generation, distribution and transmission of electricity requires the use of expensive and complicated equipment, much of which is aged, and all of which requires significant ongoing maintenance. Although we maintain our power plants and equipment, they are still subject to extended or unplanned outages because of equipment failure, weather, transmission system disruption, operator error, contractor or subcontractor failure and other factors largely beyond our control. In such events, we must either produce replacement power from our other units, which may be less efficient or more expensive to operate, or purchase power from others at unpredictable and potentially higher costs in order to meet our sales obligations. Such events could also limit our ability to make sales to customers. Therefore, the occurrence of extended or unplanned outages could adversely affect our consolidated financial results.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

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ITEM 2. PROPERTIES

Name	Location	Unit No.		Year Installed	Principal Fuel	Unit Capacity (MW) By Owner: Westar Energy	KGE	Total Company
Abilene Energy Center:	Abilene, Kansas							
Combustion Turbine		1		1973	Gas	68	—	68
Central Plains Wind Farm	Wichita County, Kansas		(a)	2009	Wind	3	—	3
Emporia Energy Center:	Emporia, Kansas							
Combustion Turbine		1		2008	Gas	45	—	45
		2		2008	Gas	45	—	45
		3		2008	Gas	47	—	47
		4		2008	Gas	46	—	46
		5		2008	Gas	161	—	161
		6		2009	Gas	159	—	159
		7		2009	Gas	160	—	160
Flat Ridge Wind Farm	Barber County, Kansas		(a)	2009	Wind	1	—	1
Gordon Evans Energy Center:	Colwich, Kansas							
Steam Turbines		1		1961	Gas—Oil	—	155	155
		2		1967	Gas—Oil	—	384	384
Combustion Turbines		1		2000	Gas	73	—	73
		2		2000	Gas	71	—	71
		3		2001	Gas	150	—	150
Hutchinson Energy Center:	Hutchinson, Kansas							
Steam Turbine		4		1965	Gas—Oil	167	—	167
Combustion Turbines		1		1974	Gas	56	—	56
		2		1974	Gas	56	—	56
		3		1974	Gas	56	—	56
		4		1975	Diesel	62	—	62
Jeffrey Energy Center (92%):	St. Marys, Kansas							
Steam Turbines		1	(b)	1978	Coal	521	145	666
		2	(b)	1980	Coal	522	145	667
		3	(b)	1983	Coal	516	143	659
La Cygne Station (50%):	La Cygne, Kansas							
Steam Turbines		1	(b)	1973	Coal	—	368	368
		2	(c)	1977	Coal	—	341	341
Lawrence Energy Center:	Lawrence, Kansas							
Steam Turbines		3		1954	Coal	51	—	51
		4		1960	Coal	109	—	109
		5		1971	Coal	371	—	371
Murray Gill Energy Center:	Wichita, Kansas							
Steam Turbines		1		1952	Gas	—	40	40
		2		1954	Gas—Oil	—	56	56
		3		1956	Gas—Oil	—	102	102
		4		1959	Gas—Oil	—	95	95
Spring Creek Energy Center:	Edmond, Oklahoma							
Combustion Turbines		1	(d)	2001	Gas	72	—	72
		2	(d)	2001	Gas	70	—	70
		3	(d)	2001	Gas	68	—	68
		4	(d)	2001	Gas	69	—	69
State Line (40%):	Joplin, Missouri							
Combined Cycle		2-1	(b)	2001	Gas	64	—	64
		2-2	(b)	2001	Gas	65	—	65
		2-3	(b)	2001	Gas	72	—	72
Tecumseh Energy Center:	Tecumseh, Kansas							
Steam Turbines		7		1957	Coal	73	—	73
		8		1962	Coal	132	—	132
Combustion Turbines		1		1972	Gas	18	—	18
		2		1972	Gas	19	—	19
Wolf Creek Generating Station (47%):	Burlington, Kansas							
Nuclear		1	(b)	1985	Uranium	—	544	544
Total						4,238	2,518	6,756

(a) Westar Energy owns Central Plains Wind Farm, which has an installed design capacity of 99 MW. Westar Energy owns 50% and purchases the other 50% of the generation from Flat Ridge Wind Farm pursuant to a purchase power agreement with BP Alternative Energy North. In total, it has an installed design capacity of 100 MW.

(b) Westar Energy jointly owns State Line (40%) while KGE jointly owns La Cygne unit 1 generating unit (50%) and Wolf Creek (47%). We jointly own and lease JEC (92%). The leased portion of JEC is consolidated as a VIE as discussed in Note 17 of the Notes to Consolidated Financial Statements, “Variable Interest Entities.” Unit capacity amounts reflect our ownership and leased percentages only.

(c) In 1987, KGE entered into a sale-leaseback transaction involving its 50% interest in the La Cygne unit 2 generating unit. We consolidate the leasing entity as a VIE as discussed in Note 17 of the Notes to Consolidated Financial Statements, “Variable Interest Entities.”

(d) We acquired Spring Creek Energy Center in 2006.

We own and have in service approximately 6,300 miles of transmission lines, approximately 23,800 miles of overhead distribution lines and approximately 4,300 miles of underground distribution lines.

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

ITEM 3. LEGAL PROCEEDINGS

Information on other legal proceedings is set forth in Notes 3, 13 and 15 of the Notes to Consolidated Financial Statements, “Rate Matters and Regulation,” “Commitments and Contingencies – EPA Lawsuit – FERC Investigation” and “Legal Proceedings,” respectively, which are incorporated herein by reference.

ITEM 4. REMOVED AND RESERVED

PART II

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

STOCK PERFORMANCE GRAPH

The following graph compares the performance of Westar Energy's common stock during the period that began on December 31, 2005, and ended on December 31, 2010, to the Standard & Poor's 500 Index (S&P 500) and the Standard & Poor's Electric Utility Index (S&P Electric Utilities). The graph assumes a $100 investment in Westar Energy's common stock and in each of the indices at the beginning of the period and a reinvestment of dividends paid on such investments throughout the period.

	Dec-2005	Dec-2006	Dec-2007	Dec-2008	Dec-2009	Dec-2010
Westar Energy Inc.	$100	$126	$131	$110	$124	$151
S&P 500	$100	$116	$122	$77	$97	$112
S&P Electric Utilities	$100	$123	$151	$112	$116	$120

STOCK TRADING

Westar Energy's common stock is listed on the New York Stock Exchange and traded under the ticker symbol WR. As of February 15, 2011, there were 22,236 common shareholders of record. For information regarding quarterly common stock price ranges for 2010 and 2009, see Note 20 of the Notes to Consolidated Financial Statements, "Quarterly Results (Unaudited)."

DIVIDENDS

Holders of Westar Energy's preferred and common stocks are entitled to dividends when and as declared by Westar Energy's board of directors.

Quarterly dividends on common and preferred stock have historically been paid on or about the first business day of January, April, July and October to shareholders of record as of or about the ninth day of the preceding month. Westar Energy's board of directors reviews the common stock dividend policy from time to time. Among the factors the board of directors considers in determining Westar Energy's dividend policy are earnings, cash flows, capitalization ratios, regulation, competition and financial loan covenants. During 2010 Westar Energy's board of directors declared four quarterly dividends of $0.31 per share, reflecting an annual dividend of $1.24 per share, compared to four quarterly dividends of $0.30 per share in 2009, reflecting an annual dividend of $1.20 per share. On February 23, 2011, Westar Energy's board of directors declared a quarterly dividend of $0.32 per share payable to shareholders on April 1, 2011. The indicated annual dividend rate is $1.28 per share.

Westar Energy's articles of incorporation restrict the payment of dividends or other distributions on its common stock while any preferred shares remain outstanding unless it meets certain capitalization ratios and other conditions. Westar Energy was not limited by any such restrictions during 2010. Further information on these restrictions is included in Note 16 of the Notes to Consolidated Financial Statements, "Common and Preferred Stock." Westar Energy does not expect these restrictions to have an impact on its ability to pay dividends on its common stock.

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ITEM 6. SELECTED FINANCIAL DATA

	Year Ended December 31,				
	2010	2009	2008	2007	2006
	(In Thousands)				
Income Statement Data:					
Total revenues	$2,056,171	$1,858,231	$1,838,996	$1,726,834	$1,605,743
Income from continuing operations	208,624	141,330	178,140	168,354	165,309
Net income attributable to common stock	202,926	174,105	177,170	167,384	164,339

	As of December 31,				
	2010	2009	2008	2007	2006
	(In Thousands)				
Balance Sheet Data:					
Total assets	$8,079,638	$7,525,483	$7,443,259	$6,395,430	$5,455,175
Long-term obligations and mandatorily redeemable preferred stock (a)	2,808,560	2,610,315	2,465,968	2,022,493	1,580,108

	Year Ended December 31,				
	2010	2009	2008	2007	2006
Common Stock Data:					
Basic earnings per share available for common stock from continuing operations (b)	$ 1.81	$ 1.28	$ 1.69	$ 1.83	$ 1.86
Basic earnings per share available for common stock (b)	$ 1.81	$ 1.58	$ 1.69	$ 1.83	$ 1.86
Dividends declared per share	$ 1.24	$ 1.20	$ 1.16	$ 1.08	$ 1.00
Book value per share	$ 21.25	$ 20.59	$ 20.18	$ 19.14	$ 17.61
Average equivalent common shares outstanding (in thousands) (c) (d) (e)	111,629	109,648	103,958	90,676	87,510

(a) Includes long-term debt, capital leases and, for 2010, long-term debt of VIEs. See Note 17 of the Notes to Consolidated Financial Statements, “Variable Interest Entities,” for additional information regarding VIEs.

(b) Earnings per share (EPS) amounts previously reported for 2006 through 2008 were adjusted to reflect the use of the two-class method. See Note 2 of the Notes to Consolidated Financial Statements, “Summary of Significant Accounting Policies—Earnings per Share,” for additional information regarding the two-class method.

(c) In 2007, Westar Energy issued and sold approximately 8.1 million shares of common stock realizing net proceeds of $195.4 million.

(d) In 2008, Westar Energy issued and sold approximately 12.8 million shares of common stock realizing net proceeds of $293.6 million.

(e) In 2010, Westar Energy issued and sold approximately 3.1 million shares of common stock realizing net proceeds of $54.7 million.

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

Certain matters discussed in Management's Discussion and Analysis are "forward-looking statements." The Private Securities Litigation Reform Act of 1995 has established that these statements qualify for safe harbors from liability. Forward-looking statements may include words like we "believe," "anticipate," "target," "expect," "estimate," "intend" and words of similar meaning. Forward-looking statements describe our future plans, objectives, expectations or goals.

EXECUTIVE SUMMARY

Overview

We are the largest electric utility in Kansas. We produce, transmit and sell electricity at retail to approximately 687,000 customers in Kansas under the regulation of the KCC. We also provide electric energy at wholesale to municipalities and electric cooperatives in Kansas under the regulation of FERC. We have other contracts for the sale, purchase or exchange of wholesale electricity with other utilities. In addition, we engage in energy marketing and purchase and sell electricity in areas outside of our retail service territory.

Key Factors Affecting Our Performance

The principal business, economic and other factors that affect our operations and financial performance include:

- Weather conditions;
- Customer conservation efforts;
- The economy;
- Performance of our electric generating facilities and networks;
- Conditions in the fuel, wholesale electricity and energy markets;
- Rate and other regulations and costs of addressing public policy initiatives including environmental regulation;
- The availability of and our access to liquidity and capital resources; and
- Capital market conditions.

Strategy

We expect to continue operating as a vertically integrated, regulated, electric utility. We strive to optimize flexibility in our planning and operations to be able to respond to uncertain and changing conditions of all manner. Working constructively with our regulators and public officials is an important part of our strategy.

Significant elements of our strategy include maintaining a flexible and diverse energy supply portfolio. In doing so, presently we are making environmental upgrades to our coal-fired power plants, developing more wind generation and building and upgrading transmission facilities, in addition to developing systems and programs to help our customers use energy more efficiently. Following is a summary of recent progress we have made on significant elements of our strategy.

- During 2010, we made capital expenditures of $111.7 million at our power plants to reduce regulated emissions.
- Along with third parties, in 2008 and 2009 we developed approximately 300 MW of wind generation facilities at three different sites in Kansas, approximately half of which we own and half of which we purchase the renewable energy produced under long-term supply contracts.
- We completed construction of a 345 kV transmission line in central Kansas in 2010.

- We are implementing SmartStar Lawrence, a smart grid project based in Lawrence, Kansas. Under this project, we will install Advanced Metering Infrastructure equipment to give customers the ability to better monitor their energy use. We qualified to receive a matching grant of approximately $19.0 million from the DOE, $3.2 million of which we received in 2010. We expect the total project to cost approximately $39.3 million.

Our plans and expectations for 2011 and beyond include:

- Investing approximately $1.0 billion at our power plants over the next three years to reduce regulated emissions.

- On December 14, 2010, we announced that we reached two separate agreements with third parties, subject to regulatory approval, to purchase under 20-year supply contracts the renewable energy produced from approximately 370 MW of wind generation beginning in late 2012.

- We began constructing a 50-mile 345 kV transmission line in south central Kansas.

- Upon receiving all necessary regulatory approvals, Prairie Wind Transmission, LLC, a joint venture company of which we own 50%, intends to construct approximately 110 miles of transmission facilities running from near Wichita, Kansas, southwest to a location near Medicine Lodge, Kansas, and then south to the Oklahoma border.

- In addition to the transmission lines described above, subject to regulatory approvals, we plan to make significant capital expenditures to develop over the next decade additional transmission lines to strengthen Kansas' electrical transmission network.

- We expect to continue improving our distribution system through vegetation management and other programs.

- We expect to continue developing and expanding programs to help customers use energy more efficiently.

Summary of Significant Items

Overview

Several significant items have impacted or may impact us and our operations since January 1, 2010:

- We reported income from continuing operations of $208.6 million and basic EPS from continuing operations of $1.81 for the year ended December 31, 2010, compared to income from continuing operations of $141.3 million and basic EPS from continuing operations of $1.28 for the year ended December 31, 2009. See "—Increase in Income from Continuing Operations" below;

- We experienced warmer than normal weather during the third quarter of 2010. As measured by cooling degree days, the weather during this period was 63% warmer than the same period in 2009 and 20% warmer than the 20-year average. Warmer weather was the key contributor to the increase in retail electricity sales in 2010;

- Economic conditions in our service territory, particularly related to some of our largest customers, showed signs of improvement in 2010. See "—Economic Conditions" below for additional information;

- We made capital expenditures of $540.1 million during 2010. See "Liquidity and Capital Resources" below for additional information;

- Westar Energy issued 1.2 million shares of common stock for $25.0 million under a Sales Agency Financing Agreement and entered into forward sale transactions with respect to an aggregate of 13.9 million shares. Westar Energy partially settled the forward sale transactions by delivering approximately 1.2 million shares of common stock for proceeds of $26.4 million. See Note 16 of the Notes to Consolidated Financial Statements, "Common and Preferred Stock," for additional information.

Increase in Income from Continuing Operations

Income from continuing operations increased $67.3 million in 2010 compared to 2009 due primarily to higher retail revenues. The increase in retail revenues was due principally to higher electricity sales, which were the result primarily of warmer weather and higher industrial electricity sales, and price increases.

Economic Conditions

Economic conditions in our service territory showed signs of improvement in 2010. Most notably, some of our commercial and industrial customers experienced increased orders and production, although not to levels experienced prior to the economic downturn. As a result, demand for electricity was higher in 2010 compared to 2009 as evidenced by the 4% and 6% increases in commercial and industrial electricity sales, respectively. We cannot predict when or if the economy may fully recover from the economic downturn or to what extent economic volatility may affect our consolidated financial results.

Current Trends

Environmental Regulation

Environmental laws and regulations affecting power plants, which relate primarily to discharges into the air, air quality, discharges of effluents into water, the use of water, and the handling, disposal and clean-up of hazardous and non-hazardous substances and wastes, continue to evolve and have become more stringent over time. We have incurred and will continue to incur significant capital and other expenditures to comply with existing and new environmental laws and regulations. While certain of these costs are recoverable through the ECRR, we cannot assure that all such costs will be recoverable in a timely manner from customers. A recent order of the KCC indicated that it may be more appropriate to recover environmental costs at La Cygne through the filing of a general rate case as opposed to the ECRR. This could increase the time between making these investments and having them reflected in the prices we charge our customers, as well as the amount we charge our customers. Our anticipated capital expenditures at La Cygne for environmental equipment for 2011 through 2013 are $429.1 million.

Greenhouse Gases

Under EPA regulations finalized in May 2010, known as the tailoring rule, the EPA began regulating GHG emissions from certain stationary sources in January 2011. The regulations are being implemented pursuant to two Federal Clear Air Act programs: the Title V Operating Permit program and the program requiring a permit if undergoing construction or major modifications, which is referred to as PSD. Obligations relating to Title V permits will include recordkeeping and monitoring requirements. With respect to PSD permits, projects that cause a significant increase in GHG emissions (currently defined to be more than 75,000 tons or more per year or 100,000 tons or more per year, depending on various factors), will be required to implement BACT. The EPA has issued guidance on what BACT entails for the control of GHGs and individual states are now required to determine what controls are required for facilities within their jurisdiction on a case-by-case basis. We cannot at this time determine the impact of these new regulations on our operations and consolidated financial results, but we believe the cost of compliance with new regulations could be material.

In December 2010, the EPA announced it will be proposing GHG NSPS rules for power plants and refineries. The rules for power plants will be proposed by July 2011, and finalized by May 2012. These rules would apply to new and existing facilities, including ours. Because these regulations have yet to be proposed, we cannot predict the impact they may have on our generating facilities or consolidated financial results, but it could be material.

Regulation of Coal Combustion Byproducts

In the course of operating our coal generation plants, we produce CCBs, including fly ash and bottom ash, which we must handle, dispose, recycle or process. We recycle approximately 45% of our fly ash and bottom ash production, principally by selling to the aggregate industry. This is referred to as "beneficial use." On June 21, 2010, the EPA published in the Federal Register a proposed rule to regulate CCBs under the RCRA. The proposed rule provides two possible options for CCB regulation, both of which technically would allow for the continued beneficial use of CCBs, but we believe might actually curtail or impair beneficial use to the extent we are able to recycle it today. The first option would subject CCBs to regulation as special waste under Subtitle C of RCRA. The second option would regulate CCBs as non-hazardous solid waste under Subtitle D of RCRA and impose national criteria applicable to CCBs disposed of in landfills and surface impoundments. While we cannot at this time estimate the impact and cost associated with future regulations of CCBs, we believe the impact on our operations and consolidated financial results could be material.

Air Emissions

Coal contains mercury. When we combust coal at our generating facilities, we emit mercury into the air. The federal CAMR permanently caps and reduces nationwide mercury emissions from new and existing coal-fired power plants. In 2008, the U.S. Court of Appeals for the District of Columbia Circuit vacated CAMR. In lieu of CAMR, the EPA has announced that it intends to propose air toxics standards under the Clean Air Act, including mercury standards, for coal and oil-fired electric generating units by March 2011 and to finalize a rule by November 2011. Without knowing what the rule will require, we cannot estimate the impact to us. However, our costs to comply with future mercury emission requirements could have a material impact on our operations and consolidated financial results.

In July 2010, the EPA proposed CATR, which would require the District of Columbia and 31 states, including Kansas, to issue regulations and develop a plan by which power plants in their respective jurisdictions will further reduce emissions of SO_2 and NOx. Reductions would be required beginning in 2012, with further reductions likely to be required in 2014. The EPA expects CATR to be finalized in the spring of 2011, but it is unclear when the states would issue implementing regulations. There are a number of uncertainties relating to this proposed rule, including whether it will be finalized and how the states will implement the requirements. As a result, we cannot determine the impact this rule will have on our operations or consolidated financial results, but it could be material.

National Ambient Air Quality Standards

Particulate matter, principally ash, is a byproduct of coal combustion. In 2011, the particulate matter NAAQS are scheduled for their required five-year review, at which time the EPA could issue more stringent standards. We cannot at this time predict the impact of any new standards on our operations or consolidated financial results, but it could be material.

The EPA is currently in the process of revising the NAAQS for ozone. The EPA has requested additional time to finalize the ozone NAAQS, which are expected to be issued in July 2011. If these revisions result in more stringent standards, we could be required to place additional NOx pollution control measures on our facilities. Without knowing the new ozone standards, we cannot determine the impact they may have on our operations or consolidated financial results, but it could be material.

Wastewater Effluent

Some water used in our operations is discharged as wastewater effluent. This wastewater may contain heavy metals and other substances deemed to be pollutants. The EPA plans to propose revisions to the rules governing such wastewater effluent from coal-fired power plants by July 2012 with final action on the proposed rules expected to occur by January 2014. Although we cannot at this time determine the impact of any new regulations, more stringent regulations could have a material impact on our operations and consolidated financial results.

Renewable Energy Standard

In May 2009, Kansas enacted legislation that mandates, among other requirements, that more energy be derived from renewable sources. In years 2011 through 2015 net renewable generation capacity must be 10% of the average peak demand for the three prior years, subject to limited exceptions. This requirement increases to 15% for years 2016 through 2019 and 20% for 2020 and thereafter. We have worked with third parties to develop approximately 300 MW of qualifying wind generation facilities, which together with the use of renewable energy credits, we expect to meet the 2011 requirement. On December 14, 2010, we announced that we reached two separate agreements with third parties, subject to regulatory approval, to purchase under 20-year supply contracts the renewable energy produced from approximately 370 MW of wind generation beginning in late 2012. We expect these agreements, along with our prior development of wind generation facilities, will satisfy our net renewable generation requirement through 2015 and contribute toward meeting the increased requirement beginning in 2016.

We expect to continue to develop renewable energy sources, which we anticipate being primarily wind generation, to meet regulatory and legal requirements as well as to diversify our generating fleet.

Allowance for Funds Used During Construction

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

	Year Ended December 31,		
	2010	2009	2008
		(In Thousands)	
Borrowed funds	$4,295	$4,857	$20,536
Equity funds	3,104	5,031	18,284
Total	$7,399	$9,888	$38,820
Average AFUDC Rates	2.6%	4.2%	6.4%

We expect both AFUDC for borrowed funds and equity funds to fluctuate over the next several years as we execute our capital expenditure program.

Interest Expense

We expect interest expense to increase over the next several years as we issue new debt securities to fund our capital expenditure program. We believe this increase will be reflected in the prices we are permitted to charge customers, as cost of capital will be a component of future rate proceedings and is also recognized in some of the other rate adjustments we are permitted to make. In addition, short-term interest rates are extremely low by historic standards. We cannot predict to what extent these conditions will persist.

Outstanding Shares of Common Stock

We expect the number of outstanding shares of Westar Energy common stock to increase over the next several years as we settle our forward sale agreements and/or issue additional shares to fund our capital expenditure program. See Note 16 of the Notes to Consolidated Financial Statements, “Common and Preferred Stock,” for additional information regarding our forward sale agreements.

Accounting Changes

The Financial Accounting Standards Board (FASB) is currently working on several projects including, among others, revenue recognition, leases, financial instruments, fair value measurements and insurance contracts, in an effort to both improve U.S. GAAP and converge U.S. GAAP with International Financial Reporting Standards. These projects could significantly change accounting guidance in these areas over the next few years. Although we cannot predict the impact that such accounting changes might have on our consolidated financial results, it could be material.

2011 Outlook

In 2011, we expect to maintain our current business strategy and regulatory approach. We anticipate price increases in the form of permitted formula adjustments. We have no way of predicting the weather and, as a result, assume for planning purposes that weather will revert to its historic average. For 2011, this means that we anticipate lower residential and commercial electricity sales than in 2010. We expect a slight increase in industrial electricity sales under the assumption that economic conditions will continue to improve. We anticipate operating and maintenance as well as selling, general and administrative expenses to trend in line with historic labor increases and inflation rates. We expect depreciation expense to increase in 2011 as a result of plant additions during the year. Furthermore, we expect to contribute $71.2 million to our pension and post-retirement benefit plans and Wolf Creek's pension plan in 2011. We plan to increase capital spending in 2011 as provided under "—Future Cash Requirements" below. To fund such capital investments, we will issue additional shares of common stock pursuant to the forward sale agreements discussed in Note 16 of the Notes to Consolidated Financial Statements, "Common and Preferred Stock." We may also issue debt.

CRITICAL ACCOUNTING ESTIMATES

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

Regulatory Accounting

We currently apply accounting standards that recognize the economic effects of rate regulation. Accordingly, we have recorded regulatory assets and liabilities when required by a regulatory order or based on regulatory precedent. Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery in our prices. Regulatory liabilities represent probable future reductions in revenue or refunds to customers.

The deferral of costs as regulatory assets is appropriate only when the future recovery of such costs is probable. In assessing probability, we consider such factors as specific regulatory orders, regulatory precedent and the current regulatory environment. Were we to deem it no longer probable that we would recover such costs, we would record a charge against income in the amount of the related regulatory assets.

As of December 31, 2010, we had recorded regulatory assets currently subject to recovery in future prices of approximately $861.1 million and regulatory liabilities of $164.0 million, as discussed in greater detail in Note 3 of the Notes to Consolidated Financial Statements, "Rate Matters and Regulation." We believe that it is probable that our regulatory assets will be recovered in the future.

Pension and Other Post-retirement Benefit Plans Actuarial Assumptions

We and Wolf Creek calculate our pension benefit and post-retirement medical benefit obligations and related costs using actuarial concepts within the guidance provided by applicable GAAP.

In accounting for our retirement plans and other post-retirement benefits, we make assumptions regarding the valuation of benefit obligations and the performance of plan assets. The reported costs of our pension plans are impacted by estimates regarding earnings on plan assets, contributions to the plan, discount rates used to determine our projected benefit obligation and pension costs and employee demographics including age, compensation levels and employment periods. Changes in these assumptions will result in changes to regulatory assets, regulatory liabilities or the amount of related pension and other post-retirement liabilities reflected on our consolidated balance sheets. Such changes may also require cash contributions.

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

Actuarial Assumption	Change in Assumption	Change in Projected Benefit Obligation (a)	Change in Pension Liability (a)	Annual Change in Projected Pension Expense (a)
			(Dollars In Thousands)	
Discount rate	0.5% decrease	$ 63,262	$ 63,262	$ 6,000
	0.5% increase	(58,993)	(58,993)	(5,843)
Salary scale	0.5% decrease	(14,485)	(14,485)	(2,788)
	0.5% increase	14,743	14,743	2,864
Rate of return on plan assets	0.5% decrease	—	—	2,623
	0.5% increase	—	—	(2,616)

(a) Increases or decreases due to changes in actuarial assumptions result in changes to regulatory assets and liabilities.

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

Actuarial Assumption	Change in Assumption	Change in Projected Benefit Obligation (a)	Change in Post-retirement Liability (a)	Annual Change in Projected Post-retirement Expense (a)
		(Dollars In Thousands)		
Discount rate	0.5% decrease	$ 7,663	$ 7,663	$ 366
	0.5% increase	(7,286)	(7,286)	(380)
Rate of return on plan assets	0.5% decrease	—	—	404
	0.5% increase	—	—	(402)

(a) Increases or decreases due to changes in actuarial assumptions result in changes to regulatory assets and liabilities.

Revenue Recognition

Electricity Sales

We record revenue at the time we deliver electricity to customers. We determine the amounts delivered to individual customers through systematic monthly readings of customer meters. At the end of each month, we estimate how much electricity we have delivered since the prior meter reading and record the corresponding unbilled revenue.

Our unbilled revenue estimate is affected by factors including fluctuations in energy demand, weather, line losses and changes in the composition of customer classes. We had estimated unbilled revenue of $53.8 million as of December 31, 2010, and $56.6 million as of December 31, 2009.

Energy Marketing Contracts

We account for energy marketing derivative contracts under the fair value 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 certain fuel supply and electricity contracts, which we record as regulatory assets or regulatory liabilities, we include the net change in fair value in revenues on our consolidated statements of income. We record the unrealized gains and losses as energy marketing long-term or short-term assets and liabilities on our consolidated balance sheets as appropriate. We use quoted market prices to value our energy marketing derivative contracts when such data are available. When market prices are not readily available or determinable, we use alternative approaches, such as model pricing. The prices we use to value these transactions reflect our best estimate of the fair value of these contracts. Results actually achieved from these activities could vary materially from intended results and could affect our consolidated financial results.

Normal Purchases and Normal Sales Exception

Determining whether a contract qualifies for the normal purchases and normal sales exception requires that we exercise judgment on whether the contract will physically deliver and requires that we ensure compliance with all of the associated qualification and documentation requirements. Revenues and expenses on contracts that qualify as normal purchases and normal sales are recognized when the underlying physical transaction is completed. Contracts which qualify for the normal purchases and normal sales exception are those for which physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time and price is not tied to an unrelated underlying derivative.

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The table below shows the fair value of energy marketing contracts outstanding as of December 31, 2010.

	Fair Value of Contracts (In Thousands)
Net fair value of contracts outstanding as of December 31, 2009 (a)	$ 4,441
Contracts outstanding at the beginning of the period that were realized or otherwise settled during the period	6,212
Changes in fair value of contracts outstanding at the beginning and end of the period	1,506
Fair value of new contracts entered into during the period	638
Net fair value of contracts outstanding as of December 31, 2010 (b)	$ 12,797

(a) Approximately $7.6 million and $6.0 million of the fair value of energy marketing contracts were recognized as a regulatory asset and regulatory liability, respectively.

(b) Approximately $7.8 million of the fair value of energy marketing contracts was recognized as a regulatory liability.

The sources of the fair values of the financial instruments related to these contracts and the maturity periods of the contracts as of December 31, 2010, are summarized in the following table.

	Fair Value of Contracts at End of Period				
Sources of Fair Value	Total Fair Value	Maturity Less Than 1 Year	Maturity 1-3 Years	Maturity 4-5 Years	Maturity Over 5 Years
	(Dollars In Thousands)				
Prices actively quoted (futures)	$ 544	$ 544	$ —	$ —	$ —
Prices provided by other external sources (swaps and forwards)	13,663	3,530	7,858	2,275	—
Prices based on option pricing models (options and other) (a)	(1,410)	(739)	(550)	(121)	—
Total fair value of contracts outstanding	$ 12,797	$ 3,335	$ 7,308	$ 2,154	$ —

(a) Options are priced using a series of techniques, such as the Black option pricing model.

Income Taxes

We use the asset and liability method of accounting for income taxes. Under this method, we recognize deferred tax assets and liabilities for the future tax consequences attributable to temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. We recognize the future tax benefits to the extent that realization of such benefits is more likely than not. We amortize deferred investment tax credits over the lives of the related properties as required by tax laws and regulatory practices. We recognize production tax credits in the year that electricity is generated to the extent that realization of such benefits is more likely than not.

We record deferred tax assets to carry forward into future periods capital losses, operating losses and tax credits. However, when we believe based on available evidence that we do not, or will not, have sufficient future capital gains or taxable income in the appropriate taxing jurisdiction to realize the entire benefit during the applicable carryforward period, we record a valuation allowance against the deferred tax asset.

The application of income tax law is complex. Laws and regulations in this area are voluminous and often ambiguous. Accordingly, we must make judgments regarding income tax exposure. Interpretations of and guidance surrounding income tax laws and regulations change over time. As a result, changes in our judgments can materially affect amounts we recognize in our consolidated financial statements. See Note 10 of the Notes to Consolidated Financial Statements, “Taxes,” for additional detail on our accounting for income taxes.

Asset Retirement Obligations

Legal Liability

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 the asset retirement obligation (ARO) is capitalized and depreciated over the remaining life of the asset. We estimate our AROs based on the fair value of the AROs we incurred at the time the related long-lived assets were either acquired, placed in service or when regulations establishing the obligation became effective.

We initially recorded AROs at fair value for the estimated cost to decommission Wolf Creek (our 47% share), retire our wind generating facilities, dispose of asbestos insulating material at our power plants, remediate ash disposal ponds and dispose of polychlorinated biphenyl contaminated oil. In determining our AROs, we make assumptions regarding probable future disposal costs. A change in these assumptions could have a significant impact on the AROs reflected on our consolidated balance sheets.

As of December 31, 2010 and 2009, we have recorded AROs of $126.0 million and $119.5 million, respectively. For additional information on our legal AROs, see Note 14 of the Notes to Consolidated Financial Statements, "Asset Retirement Obligations."

Non-Legal Liability – Cost of Removal

We recover in our prices the costs to dispose of plant assets that do not represent legal retirement obligations. As of December 31, 2010 and 2009, we had $70.3 million and $68.1 million, respectively, in amounts collected, but not yet spent, for removal costs classified as a regulatory liability.

Contingencies and Litigation

We are currently involved in certain legal proceedings and have estimated the probable cost for the resolution of these claims. These estimates are based on an analysis of potential results, assuming a combination of litigation and settlement strategies. It is possible that our future consolidated financial results could be materially affected by changes in our assumptions. See Note 13 and 15 of the Notes to Consolidated Financial Statements, "Commitments and Contingencies" and "Legal Proceedings," for more detailed information.

OPERATING RESULTS

We evaluate operating results based on EPS. We have various classifications of revenues, defined as follows:

Retail: Sales of electricity to residential, commercial and industrial customers. Classification of customers as residential, commercial or industrial requires judgment and our classifications may be different from other companies. Assignment of tariffs is not dependent on classification.

Other retail: Sales of electricity for lighting public streets and highways, net of revenue subject to refund.

Wholesale: Sales of electricity to electric cooperatives, municipalities and other electric utilities, the prices for which are either based on cost or prevailing market prices as prescribed by FERC authority. This category also includes changes in valuations of contracts for the sale of such electricity that have yet to settle. Margins realized from sales based on prevailing market prices generally serve to offset our retail prices and the cost-based prices charged to certain wholesale customers.

Transmission: Reflects transmission revenues, including those based on tariffs with the SPP.

Other: Miscellaneous electric revenues including ancillary service revenues and rent from electric property leased to others. This category also includes energy marketing transactions unrelated to the production of our generating assets, changes in valuations of related contracts and fees we earn for marketing services that we provide for third parties.

Electric utility revenues are impacted by things such as rate regulation, fuel costs, customer conservation efforts, the economy and competitive forces. Changing weather also affects the amount of electricity our customers use as electricity sales are seasonal. As a summer peaking utility, the third quarter typically accounts for our greatest electricity sales. Hot summer temperatures and cold winter temperatures prompt more demand, especially among residential customers. Mild weather reduces customer demand. Our wholesale revenues are impacted by, among other factors, demand, cost and availability of fuel and purchased power, price volatility, available generation capacity, transmission availability and weather.

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2010 Compared to 2009

Below we discuss our operating results for the year ended December 31, 2010, compared to the results for the year ended December 31, 2009. Significant changes in results of operations shown in the table immediately below are further explained in the descriptions that follow.

	Year Ended December 31,			
	2010	2009	Change	% Change
	(Dollars In Thousands, Except Per Share Amounts)			
REVENUES:				
Residential	$ 661,177	$ 576,896	$ 84,281	14.6
Commercial	572,062	529,847	42,215	8.0
Industrial	318,249	291,754	26,495	9.1
Other retail	(12,703)	(18,516)	5,813	31.4
Total Retail Revenues	1,538,785	1,379,981	158,804	11.5
Wholesale	334,669	308,269	26,400	8.6
Transmission (a)	144,513	132,450	12,063	9.1
Other	38,204	37,531	673	1.8
Total Revenues	2,056,171	1,858,231	197,940	10.7
OPERATING EXPENSES:				
Fuel and purchased power	583,361	534,864	48,497	9.1
Operating and maintenance	520,409	516,930	3,479	0.7
Depreciation and amortization	271,937	251,534	20,403	8.1
Selling, general and administrative	207,607	199,961	7,646	3.8
Total Operating Expenses	1,583,314	1,503,289	80,025	5.3
INCOME FROM OPERATIONS	472,857	354,942	117,915	33.2
OTHER INCOME (EXPENSE):				
Investment earnings	7,026	12,658	(5,632)	(44.5)
Other income	5,369	7,128	(1,759)	(24.7)
Other expense	(16,655)	(17,188)	533	3.1
Total Other (Expense) Income	(4,260)	2,598	(6,858)	(264.0)
Interest expense	174,941	157,360	17,581	11.2
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	293,656	200,180	93,476	46.7
Income tax expense	85,032	58,850	26,182	44.5
INCOME FROM CONTINUING OPERATIONS	208,624	141,330	67,294	47.6
Results of discontinued operations, net of tax	—	33,745	(33,745)	(100.0)
NET INCOME	208,624	175,075	33,549	19.2
Less: Net income attributable to noncontrolling interests	4,728	—	4,728	(b)
NET INCOME ATTRIBUTABLE TO WESTAR ENERGY	203,896	175,075	28,821	16.5
Preferred dividends	970	970	—	—
NET INCOME ATTRIBUTABLE TO COMMON STOCK	$ 202,926	$ 174,105	$ 28,821	16.6
BASIC EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING:				
Earnings available from continuing operations	$ 1.81	$ 1.28	$ 0.53	41.4
Discontinued operations, net of tax	—	0.30	(0.30)	(100.0)
Earnings per common share	$ 1.81	$ 1.58	$ 0.23	14.6

(a) **Transmission:** Reflects revenue derived from an SPP network transmission tariff. In 2010, our SPP network transmission costs were $116.4 million. This amount, less $14.4 million retained by the SPP as administration cost, was returned to us as revenue. In 2009, our SPP network transmission costs were $105.4 million with an administration cost of $11.2 million retained by the SPP.

(b) Cannot divide by zero.

Gross Margin

Fuel and purchased power costs fluctuate with electricity sales and unit costs. As permitted by regulators, we adjust our retail prices to reflect changes in the costs of fuel and purchased power. Fuel and purchased power costs for wholesale customers are recovered at prevailing market prices or based on a predetermined formula with a price adjustment approved by FERC. As a result, changes in fuel and purchased power costs are offset in revenues with minimal impact on net income. For this reason, we believe gross margin, although a non-GAAP measure, is useful for understanding and analyzing changes in our operating performance from one period to the next. We calculate gross margin as total revenues less the sum of fuel and purchased power costs and SPP network transmission costs. Transmission costs reflect the costs of providing network transmission service. Accordingly, in calculating gross margin, we recognize the net value of this transmission activity as shown in the table immediately following. However, we record transmission costs as operating and maintenance expense on our consolidated statements of income. The following table summarizes our gross margin for the years ended December 31, 2010 and 2009.

	Year Ended December 31,			
	2010	2009	Change	% Change
	(Dollars In Thousands)			
REVENUES:				
Residential	$ 661,177	$ 576,896	$ 84,281	14.6
Commercial	572,062	529,847	42,215	8.0
Industrial	318,249	291,754	26,495	9.1
Other retail	(12,703)	(18,516)	5,813	31.4
Total Retail Revenues	1,538,785	1,379,981	158,804	11.5
Wholesale	334,669	308,269	26,400	8.6
Transmission	144,513	132,450	12,063	9.1
Other	38,204	37,531	673	1.8
Total Revenues	2,056,171	1,858,231	197,940	10.7
Less: Fuel and purchased power expense	583,361	534,864	48,497	9.1
SPP network transmission costs	116,449	105,401	11,048	10.5
Gross Margin	$1,356,361	$1,217,966	$138,395	11.4

The following table reflects changes in electricity sales for the years ended December 31, 2010 and 2009. No electricity sales are shown for transmission or other as they are not directly related to the amount of electricity we sell.

	Year Ended December 31,			
	2010	2009	Change	% Change
	(Thousands of MWh)			
ELECTRICITY SALES:				
Residential	6,957	6,404	553	8.6
Commercial	7,519	7,235	284	3.9
Industrial	5,468	5,145	323	6.3
Other retail	89	88	1	1.1
Total Retail	20,033	18,872	1,161	6.2
Wholesale	8,712	8,788	(76)	(0.9)
Total	28,745	27,660	1,085	3.9

Gross margin increased in 2010 compared to 2009 due principally to an increase in total retail revenues. Of the $158.8 million increase in total retail revenues, 53% was attributable to higher electricity sales and 47% was due to higher prices as discussed in Note 3 of the Notes to Consolidated Financial Statements, “Rate Matters and Regulation.” Retail electricity sales increased due primarily to the effects of warmer weather, which particularly impacted residential electricity sales, and for reasons we believe to be principally related to improved economic conditions. As measured by cooling degree days, the weather during 2010 was 47% warmer than 2009 and 25% warmer than the 20-year average. While weather also affects commercial and industrial customers, those electricity sales typically are not as sensitive to weather as residential electricity sales. We believe improving economic conditions are why some of our commercial and industrial customers experienced increased orders and production in 2010, which lead to increased electricity sales to them. Economic conditions generally have not recovered to levels experienced prior to the economic downturn.

Income from operations is the most directly comparable measure to gross margin that is calculated and presented in accordance with GAAP in our consolidated statements of income. Our presentation of gross margin should not be considered in isolation or as a substitute for income from operations. Additionally, our presentation of gross margin may not be comparable to similarly titled measures reported by other companies. The following table reconciles income from operations with gross margin for the years ended December 31, 2010 and 2009.

	Year Ended December 31,			
	2010	2009	Change	% Change
	(Dollars In Thousands)			
Gross margin	$1,356,361	$1,217,966	$138,395	11.4
Add: SPP network transmission costs	116,449	105,401	11,048	10.5
Less: Operating and maintenance expense	520,409	516,930	3,479	0.7
Depreciation and amortization expense	271,937	251,534	20,403	8.1
Selling, general and administrative expense	207,607	199,961	7,646	3.8
Income from operations	$ 472,857	$ 354,942	$117,915	33.2

Operating Expenses and Other Income and Expense Items

	Year Ended December 31,			
	2010	2009	Change	% Change
	(Dollars in Thousands)			
Operating and maintenance expense	$520,409	$516,930	$ 3,479	0.7

Operating and maintenance expense increased due primarily to higher SPP network transmission costs of $11.0 million, which were offset by higher SPP network transmission revenues of $7.9 million, higher power plant maintenance costs of $7.6 million and higher maintenance costs of $5.6 million for our electrical distribution system. The higher power plant maintenance costs were due primarily to higher costs at Wolf Creek and our wind generation facilities while the increase in maintenance costs for our electrical distribution system was due principally to additional tree trimming and other line clearance activities in 2010. Offsetting these increases was a $20.4 million reduction resulting from the consolidation of VIEs as discussed in Note 17 of the Notes to Consolidated Financial Statements, “Variable Interest Entities,” and a $5.0 million reduction in our maximum liability for environmental remediation costs associated with assets we divested many years ago.

	Year Ended December 31,			
	2010	2009	Change	% Change
	(Dollars in Thousands)			
Depreciation and amortization expense	$271,937	$251,534	$20,403	8.1

Depreciation and amortization expense increased primarily to reflect the addition of wind generation facilities, new generating plant, air quality controls at our power plants and other plant additions. We also recorded additional depreciation expense of $6.1 million as a result of consolidating VIEs as discussed in Note 17 of the Notes to Consolidated Financial Statements, “Variable Interest Entities.”

	Year Ended December 31,			
	2010	2009	Change	% Change
	(Dollars in Thousands)			
Selling, general and administrative expense	$207,607	$199,961	$ 7,646	3.8

A significant amount of our non-union, non-executive employee compensation is at-risk to employees and, therefore, payable only in the event we meet pre-established operating and financial objectives. Likewise, under our executive long-term incentive and share award plan, shares are issued only when certain service conditions are met and/or we meet pre-established financial objectives. In 2010 we adjusted these compensation plans to better align compensation with our financial performance. Selling, general and administrative expense increased due principally to higher compensation expense of $12.9 million that was primarily the result of the aforementioned plan adjustments and our improved financial performance. This increase was partially offset by our having recorded a $4.0 million expense in 2009 related to the settlement of the EPA lawsuit discussed in Note 13 of the Notes to Consolidated Financial Statements, “Commitments and Contingencies.”

	Year Ended December 31,			
	2010	2009	Change	% Change
	(Dollars in Thousands)			
Investment earnings	$7,026	$12,658	$(5,632)	(44.5)

Investment earnings decreased due principally to our having recorded lower gains on investments held in a trust to fund retirement benefits. We recorded gains on these investments of $4.8 million in 2010 compared to gains of $8.4 million recorded in 2009.

	Year Ended December 31,			
	2010	2009	Change	% Change
	(Dollars in Thousands)			
Interest expense	$174,941	$157,360	$17,581	11.2

Interest expense increased due primarily to our having recorded additional interest expense of $12.2 million as a result of consolidating VIEs as discussed in Note 17 of the Notes to Consolidated Financial Statements, “Variable Interest Entities,” and interest on additional debt issued in June 2009 to fund capital investments.

	Year Ended December 31,			
	2010	2009	Change	% Change
	(Dollars in Thousands)			
Income tax expense	$85,032	$58,850	$26,182	44.5

Income tax expense increased due principally to higher income from continuing operations before income taxes.

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2009 Compared to 2008

Below we discuss our operating results for the year ended December 31, 2009, compared to the results for the year ended December 31, 2008. Significant changes in results of operations shown in the table immediately below are further explained in the descriptions that follow.

	Year Ended December 31,			
	2009	2008	Change	% Change
	(Dollars In Thousands, Except Per Share Amounts)			
REVENUES:				
Residential	$ 576,896	$ 516,926	$ 59,970	11.6
Commercial	529,847	485,016	44,831	9.2
Industrial	291,754	291,863	(109)	(b)
Other retail	(18,516)	(6,093)	(12,423)	(203.9)
Total Retail Revenues	1,379,981	1,287,712	92,269	7.2
Wholesale	308,269	413,809	(105,540)	(25.5)
Transmission (a)	132,450	98,549	33,901	34.4
Other	37,531	38,926	(1,395)	(3.6)
Total Revenues	1,858,231	1,838,996	19,235	1.0
OPERATING EXPENSES:				
Fuel and purchased power	534,864	694,348	(159,484)	(23.0)
Operating and maintenance	516,930	471,838	45,092	9.6
Depreciation and amortization	251,534	203,738	47,796	23.5
Selling, general and administrative	199,961	184,427	15,534	8.4
Total Operating Expenses	1,503,289	1,554,351	(51,062)	(3.3)
INCOME FROM OPERATIONS	354,942	284,645	70,297	24.7
OTHER INCOME (EXPENSE):				
Investment earnings (losses)	12,658	(10,453)	23,111	221.1
Other income	7,128	29,658	(22,530)	(76.0)
Other expense	(17,188)	(15,324)	(1,864)	(12.2)
Total Other Income	2,598	3,881	(1,283)	(33.1)
Interest expense	157,360	106,450	50,910	47.8
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	200,180	182,076	18,104	9.9
Income tax expense	58,850	3,936	54,914	(c)
INCOME FROM CONTINUING OPERATIONS	141,330	178,140	(36,810)	(20.7)
Results of discontinued operations, net of tax	33,745	—	33,745	(d)
NET INCOME	175,075	178,140	(3,065)	(1.7)
Preferred dividends	970	970	—	—
NET INCOME ATTRIBUTABLE TO COMMON STOCK	$ 174,105	$ 177,170	$ (3,065)	(1.7)
BASIC EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING:				
Basic earnings available from continuing operations	$ 1.28	$ 1.69	$ (0.41)	(24.3)
Discontinued operations, net of tax	0.30	—	0.30	(d)
Basic earnings per common share	$ 1.58	$ 1.69	$ (0.11)	(6.5)

(a) **Transmission:** Reflects revenue derived from an SPP network transmission tariff. In 2009, our SPP network transmission costs were $105.4 million. This amount, less $11.2 million retained by the SPP as administration cost, was returned to us as revenue. In 2008, our SPP network transmission costs were $77.9 million with an administration cost of $6.7 million retained by the SPP.

(b) Change less than 0.1%.

(c) Change greater than 1000%.

(d) Cannot divide by zero.

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Gross Margin

The following table summarizes our gross margin for the years ended December 31, 2009 and 2008.

	Year Ended December 31,			
	2009	2008	Change	% Change
	(Dollars In Thousands)			
REVENUES:				
Residential	$ 576,896	$ 516,926	$ 59,970	11.6
Commercial	529,847	485,016	44,831	9.2
Industrial	291,754	291,863	(109)	(a)
Other retail	(18,516)	(6,093)	(12,423)	(203.9)
Total Retail Revenues	1,379,981	1,287,712	92,269	7.2
Wholesale	308,269	413,809	(105,540)	(25.5)
Transmission	132,450	98,549	33,901	34.4
Other	37,531	38,926	(1,395)	(3.6)
Total Revenues	1,858,231	1,838,996	19,235	1.0
Less: Fuel and purchased power expense	534,864	694,348	(159,484)	(23.0)
SPP network transmission costs	105,401	77,871	27,530	35.4
Gross Margin	$1,217,966	$1,066,777	$ 151,189	14.2

(a) Change less than 0.1%.

The following table reflects changes in electricity sales for the years ended December 31, 2009 and 2008. No electricity sales are shown for transmission or other as they are unrelated to the amount of electricity we sell.

	Year Ended December 31,			
	2009	2008	Change	% Change
	(Thousands of MWh)			
ELECTRICITY SALES:				
Residential	6,404	6,494	(90)	(1.4)
Commercial	7,235	7,363	(128)	(1.7)
Industrial	5,145	5,769	(624)	(10.8)
Other retail	88	88	—	—
Total Retail	18,872	19,714	(842)	(4.3)
Wholesale	8,788	9,384	(596)	(6.4)
Total	27,660	29,098	(1,438)	(4.9)

The increase in gross margin in 2009 compared to 2008 was due principally to the increase in total retail revenues. Total retail revenues increased primarily as a result of price increases authorized by the KCC, which more than offset the decrease in total retail electricity sales. The decreases in both residential and commercial electricity sales were attributable primarily to cooler weather, particularly during the third quarter of 2009. As measured by cooling degree days, the weather during the third quarter of 2009 was 14% cooler than the same period in 2008 and 27% cooler than the 20-year average. Industrial electricity sales decreased due principally to the effects of recessionary conditions that served to reduce industrial demand for electricity. In addition, wholesale revenues decreased compared to 2008 due principally to a 17% lower average market price for these sales that was the result primarily of reduced demand and lower natural gas prices. Substantially all of the margins realized on these electricity sales are returned to our customers.

The following table reconciles income from operations with gross margin for the years ended December 31, 2009 and 2008.

	Year Ended December 31,			
	2009	2008	Change	% Change
	(Dollars In Thousands)			
Gross margin	$1,217,966	$1,066,777	$151,189	14.2
Add: SPP network transmission costs	105,401	77,871	27,530	35.4
Less: Operating and maintenance expense	516,930	471,838	45,092	9.6
Depreciation and amortization expense	251,534	203,738	47,796	23.5
Selling, general and administrative expense	199,961	184,427	15,534	8.4
Income from operations	$ 354,942	$ 284,645	$ 70,297	24.7

Operating Expenses and Other Income and Expense Items

	Year Ended December 31,			
	2009	2008	Change	% Change
		(Dollars in Thousands)		
Operating and maintenance expense	$516,930	$471,838	$45,092	9.6

Operating and maintenance expense increased due primarily to a $27.5 million increase in SPP network transmission costs, which was offset by higher transmission revenues of $33.9 million. Maintenance expense increased $8.2 million due principally to a $5.5 million increase in amounts expensed for previously deferred storm costs and higher maintenance costs of $3.3 million for our new generating facilities.

	Year Ended December 31,			
	2009	2008	Change	% Change
		(Dollars in Thousands)		
Depreciation and amortization expense	$251,534	$203,738	$47,796	23.5

We completed a number of large construction projects in 2009 and 2008. Consequently, depreciation and amortization expense increased primarily as a result of these plant additions. During 2009, we recorded depreciation expense of $9.3 million for Emporia Energy Center, $10.3 million for wind generation facilities and $5.7 million for various transmission projects. During 2008, we recorded depreciation expense of $3.4 million for Emporia Energy Center and $0.2 million for the same transmission projects described above. We did not record any depreciation expense for the wind generation facilities in 2008 because they were not yet in service.

	Year Ended December 31,			
	2009	2008	Change	% Change
		(Dollars in Thousands)		
Selling, general and administrative expense	$199,961	$184,427	$15,534	8.4

The increase in selling, general and administrative expense was due primarily to a $7.0 million increase in pension and other employee benefit costs. In addition, we recorded a $4.0 million expense related to the settlement of the EPA lawsuit discussed in Note 13 of the Notes to Consolidated Financial Statements, “Commitments and Contingencies.”

	Year Ended December 31,			
	2009	2008	Change	% Change
		(Dollars in Thousands)		
Investment earnings (losses)	$12,658	$(10,453)	$23,111	221.1

Investment earnings increased in 2009 compared to 2008 due principally to our having recorded an $8.4 million gain on investments held in a trust to fund non-qualified retirement benefits. We recorded a $10.9 million loss on those investments in 2008.

	Year Ended December 31,			
	2009	2008	Change	% Change
		(Dollars in Thousands)		
Other income	$7,128	$29,658	$(22,530)	(76.0)

Other income decreased due principally to our having recorded less equity AFUDC and corporate-owned life insurance (COLI) benefit in 2009. We recorded $5.0 million of equity AFUDC in 2009 compared to $18.3 million of equity AFUDC recorded during 2008. This decrease reflects the completion of several large construction projects in 2009. In addition, we recorded $0.4 million of COLI benefit in 2009 compared to $5.8 million of COLI benefit recorded in 2008.

	Year Ended December 31,			
	2009	2008	Change	% Change
	(Dollars in Thousands)			
Interest expense	$157,360	$106,450	$50,910	47.8

In 2008, we reversed $17.8 million of accrued interest associated with uncertain income tax positions, which reduced interest expense. We did not record such a reversal in 2009 and, as a result, our interest expense was higher. Absent this reversal, interest expense increased $33.1 million in 2009 compared to 2008 due principally to interest on additional debt issued to fund capital investments. Contributing to the increase was our having recorded $15.7 million less for capitalized interest as a result of completing several large construction projects in 2009. These factors were offset partially by a $7.5 million decrease in interest related to lower interest rates and less borrowing under Westar Energy's revolving credit facility.

	Year Ended December 31,			
	2009	2008	Change	% Change
	(Dollars in Thousands)			
Income tax expense	$58,850	$3,936	$54,914	(a)

(a) Change greater than 1000%.

In 2008, we recognized $28.7 million of previously unrecognized income tax benefits associated with uncertain income tax positions and $14.6 million in state tax credits related to investments and jobs creation within the state of Kansas, both of which decreased income tax expense. We did not recognize similar income tax benefits in continuing operations in 2009.

Financial Condition

A number of factors affected amounts recorded on our balance sheet as of December 31, 2010, compared to December 31, 2009.

As a result of consolidating the VIEs discussed in Note 17 of the Notes to Consolidated Financial Statements, "Variable Interest Entities," we had recorded as of December 31, 2010, property, plant and equipment of variable interest entities, net, of $345.0 million, current maturities of long-term debt of variable interest entities of $30.2 million and long-term debt of variable interest entities, net, of $278.2 million.

The fair market value of energy marketing contracts increased $8.4 million to $12.8 million at December 31, 2010. This was due principally to the settlement of a fuel supply contract that was recorded as a $7.5 million liability at December 31, 2009. Changes in the measurement of this fuel supply contract have an offsetting impact to regulatory assets.

Tax receivable decreased $28.5 million due principally to the receipt of federal and state tax refunds related to the settlement of prior tax years.

Regulatory assets, net of regulatory liabilities, decreased $18.0 million to $697.0 million at December 31, 2010, from $715.0 million at December 31, 2009. Total regulatory assets increased $5.3 million due primarily to a $61.1 million increase in accrued employee benefits and $9.9 million increase due to the accumulation of energy efficiency costs. Increases were offset by $21.5 million amortization of deferred storm costs, $13.3 million decrease in previously deferred fuel expense, $11.5 million decrease in net amounts due from customers for future income taxes and $9.8 million amortization of previously deferred amounts for a Wolf Creek refueling and maintenance outage. Total regulatory liabilities increased $23.3 million due principally to a $14.7 million increase resulting from the increase in the fair value measurement of our NDT assets, $13.3 million resulting from consolidating our 50% leasehold interest in La Cygne unit 2 and a $7.7 million increase in the fair value measurement of a treasury yield hedge we entered into in anticipation of a future debt issuance. Increases to regulatory liabilities were partially offset by an $11.1 million decrease in our refund obligation related to the RECA.

Short-term debt decreased $16.1 million due principally to increased cash receipts from customers, the above mentioned tax refund and the issuance of common stock.

Other current liabilities increased $53.3 million, other long-term liabilities decreased $58.4 million and current deferred tax assets increased $22.3 million due primarily to a change in the status of legal proceedings involving two former executives who we dismissed in 2002. In 2010, the U.S. government dismissed criminal charges against them which allowed for the resumption of an arbitration proceeding against them which had previously been stayed pending resolution of the criminal charges. We expect arbitration to conclude within the next year. For additional information, see Note 15 of the Notes to Consolidated Financial Statements, “Legal Proceedings.”

Deferred income taxes increased $138.2 million due principally to the recording of tax benefits resulting from the use of accelerated depreciation methods, including $48.4 million resulting from the extension of the bonus depreciation tax provisions.

Unamortized investment tax credits decreased $26.4 million since we do not expect to realize all of the state investment tax credits prior to expiration that we earned on investments in plant located in the state of Kansas.

Accrued employee benefits increased $50.2 million due primarily to a higher projected benefit obligation for our and Wolf Creek’s pension plans. We recognize as a regulatory asset or regulatory liability the difference between the fair value of pension and post-retirement benefit plan assets and the liabilities for pension and post-retirement benefit plans. See Notes 11 and 12 of the Notes to Consolidated Financial Statements, “Employee Benefit Plans” and “Wolf Creek Employee Benefit Plans,” respectively, for additional information.

LIQUIDITY AND CAPITAL RESOURCES

Overview

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

During 2011, we plan to increase our capital spending and expect to contribute to our pension trust. We continue to believe that we will have the ability to pay dividends. Uncertainties affecting our ability to meet cash requirements include, among others: factors affecting revenues described in “—Operating Results” above, economic conditions, regulatory actions, compliance with environmental regulations and conditions in the capital markets.

Capital Structure

As of December 31, 2010 and 2009, our capital structure, excluding short-term debt, was as follows:

	2010	2009
Common equity	46%	47%
Preferred stock	<1%	<1%
Noncontrolling interests	<1%	—
Long-term debt (a)	54%	52%

(a) Includes long-term debt of VIEs in 2010. See Note 17 of the Notes to Consolidated Financial Statements, "Variable Interest Entities," for additional information.

Short-Term Borrowings

Westar Energy has a $730.0 million revolving credit facility with a syndicate of banks that terminates on March 17, 2012. As discussed above, we use the revolving credit facility primarily to fund investments in capital equipment and to help meet our day-to-day cash requirements including, among other items, fuel and purchased power, dividends, interest payments, income taxes and pension contributions. As of February 15, 2011, $264.0 million had been borrowed and an additional $21.5 million of letters of credit had been issued under the revolving credit facility.

On January 27, 2010, FERC approved our request for authority to issue short-term securities in an aggregate amount up to $1.0 billion including, without limitation, by increasing the size of Westar Energy's revolving credit facility. In February 2011, Westar Energy entered into a new revolving credit facility with a similar syndicate of banks for an additional $270.0 million. The commitments under this facility terminate in February 2015.

A default by Westar Energy or KGE under other indebtedness totaling more than $25.0 million would be a default under both revolving credit facilities. Westar Energy is required to maintain a consolidated indebtedness to consolidated capitalization ratio not greater than 65% at all times. At December 31, 2010, our ratio was 54%. Available liquidity under the facilities is not impacted by a decline in Westar Energy's credit ratings.

Debt Financing

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

Under the Westar Energy mortgage, the issuance of bonds is subject to limitations based on the amount of bondable property additions. In addition, so long as any bonds issued prior to January 1, 1997, remain outstanding, the mortgage prohibits additional first mortgage bonds from being issued, except in connection with certain refundings, unless Westar Energy's unconsolidated net earnings available for interest, depreciation and property retirement (which as defined, does not include earnings or losses attributable to the ownership of securities of subsidiaries), for a period of 12 consecutive months within 15 months preceding the issuance, are not less than the greater of twice the annual interest charges on or 10% of the principal amount of all first mortgage bonds outstanding after giving effect to the proposed issuance. As of December 31, 2010, based on an assumed interest rate of 5.90%, approximately $817.0 million principal amount of additional first mortgage bonds could be issued under the most restrictive provisions in the mortgage, except in connection with certain refundings.

Under the KGE mortgage, the issuance of bonds is subject to limitations based on the amount of bondable property additions. In addition, the mortgage prohibits additional first mortgage bonds from being issued, except in connection with certain refundings, unless KGE's net earnings before income taxes and before provision for retirement and depreciation of property for a period of 12 consecutive months within 15 months preceding the issuance are not less than either two and one-half times the annual interest charges on or 10% of the principal amount of all KGE first mortgage bonds outstanding after giving effect to the proposed issuance. As of December 31, 2010, approximately $635.0 million principal amount of additional KGE first mortgage bonds could be issued under the most restrictive provisions in the mortgage.

Some of our debt instruments contain restrictions that require us to maintain leverage ratios as defined in the agreements. We calculate these ratios in accordance with our credit agreements. These ratios are used solely to determine compliance with our various debt covenants. We were in compliance with these covenants as of December 31, 2010.

As of December 31, 2010, we had $121.9 million of variable rate, tax-exempt bonds. Interest rates payable under these bonds are normally set by auctions, which occur every 35 days. However, auctions for these bonds have failed over the past few years, resulting in volatile alternative index-based interest rates for these bonds. With the KCC's approval, on October 15, 2009, KGE refinanced $50.0 million of auction rate bonds at a fixed interest rate of 5.00% and a maturity date of June 1, 2031. We continue to monitor the credit markets and evaluate our options with respect to our remaining auction rate bonds.

On August 3, 2009, Westar Energy repaid $145.1 million principal amount of 7.125% unsecured senior notes with borrowings under Westar Energy's revolving credit facility.

On June 11, 2009, KGE issued $300.0 million principal amount of first mortgage bonds at a discount yielding 6.725%, bearing stated interest at 6.70% and maturing on June 15, 2019. KGE received net proceeds of $297.5 million.

In addition, KGE amended its Mortgage and Deed of Trust, dated April 1, 1940, as supplemented, in June 2009 to increase the maximum amount of KGE first mortgage bonds authorized to be issued from $2.0 billion to $3.5 billion.

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

Impact of Credit Ratings on Debt Financing

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

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

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

On June 1, 2010, and May 19, 2010, respectively, Fitch and Moody's revised their outlooks for Westar Energy and KGE credit ratings to positive from stable. Additionally, on April 27, 2010, S&P upgraded its credit ratings for Westar Energy's and KGE's first mortgage bonds/senior secured debt from BBB to BBB+. S&P also upgraded its credit rating for Westar Energy's unsecured debt from BBB- to BBB and changed its outlook for the ratings from positive to stable.

As of February 15, 2011, ratings with these agencies are as shown in the table below.

	Westar Energy First Mortgage Bond Rating	KGE First Mortgage Bond Rating	Westar Energy Unsecured Debt	Rating Outlook
Moody's	Baa1	Baa1	Baa3	Positive
S&P	BBB+	BBB+	BBB	Stable
Fitch	BBB+	BBB+	BBB	Positive

Certain of our derivative instruments contain collateral provisions subject to credit agency ratings of our senior unsecured debt. If our senior unsecured debt ratings were to decrease or fall below investment grade, the counterparties to the derivative instruments, pursuant to the provisions, could require collateralization on derivative instruments. The aggregate fair value of all derivative instruments with objective credit-risk-related contingent features that were in a liability position as of December 31, 2010 and 2009, was $1.6 million and $1.4 million, respectively, for which we had posted no collateral. If all credit-risk-related contingent features underlying these agreements had been triggered as of December 31, 2010 and 2009, we would have been required to provide to our counterparties $1.6 million and $0.1 million, respectively, of additional collateral after taking into consideration the offsetting impact of derivative assets and net accounts receivable.

Common Stock Issuance

Westar Energy's articles of incorporation, as amended, provide for 150,000,000 authorized shares of common stock. As of December 31, 2010, we had 112,128,068 shares issued and outstanding.

Through a Sales Agency Financing Agreement entered into with a broker dealer subsidiary of a bank in 2007, Westar Energy sold 1.2 million shares of common stock for $25.0 million in 2010 and 1.1 million shares of common stock for $26.9 million in 2008. Westar Energy did not sell any shares of common stock under this agreement during 2009.

During 2010, Westar Energy entered into two separate forward sale agreements with banks. The use of a forward sale agreement allows Westar Energy the means to minimize equity market uncertainty by pricing a common stock offering under then existing market conditions while mitigating share dilution by postponing the issuance of common stock until funds are needed. Westar Energy is also better able to match the timing of its financing needs with its capital investment and regulatory plans. The forward sale transactions are entered into at market prices; therefore, the forward sale agreements have no initial fair value. Westar Energy will not receive any proceeds from the sale of common stock under the forward sale agreements until transactions are settled. Upon settlement, Westar Energy will record the forward sale agreements within equity. Except in specified circumstances or events that would require physical share settlement, Westar Energy is able to elect to settle any forward sale transactions by means of physical share, cash or net share settlement, and is also able to elect to settle the forward sale transactions in whole, or in part, earlier than the stated maturity dates. Currently, Westar Energy anticipates settling the forward sale transactions through physical share settlement. The shares under the forward sale agreements were initially priced when the agreements were entered into and are subject to certain fixed pricing adjustments during the term of the agreements. Accordingly, assuming physical share settlement, Westar's net proceeds from the forward sale transactions will represent the prices established by the forward sale agreements applicable to the time periods in which physical settlement occurs.

Westar Energy entered into one such forward sale agreement on November 4, 2010. Under the terms of the agreement, the bank, as forward seller, borrowed 7.5 million shares of Westar Energy's common stock from third parties and sold them to a group of underwriters for $25.54 per share. Under an over-allotment option included in the agreement, the underwriters purchased approximately 1.0 million additional shares on November 5, 2010, also for $25.54 per share, which increased the total number of shares under the forward sale agreement to approximately 8.5 million shares. The underwriters receive a commission equal to 3.5% of the sales price of all shares sold under the agreement. Westar Energy must settle the forward sale agreement within 18 months of the transaction date. Assuming physical share settlement of this agreement at December 31, 2010, Westar Energy would have received aggregate proceeds of approximately $206.2 million, net of commission, based on an average forward price of $24.32 per share.

On April 2, 2010, Westar Energy entered into a new, three-year Sales Agency Financing Agreement and forward sale agreement. The maximum amount that Westar Energy may offer and sell under the agreements is the lesser of an aggregate of $500.0 million or approximately 22.0 million shares, subject to adjustment for share splits, share combinations and share dividends. Under the terms of the Sales Agency Financing Agreement, Westar Energy may offer and sell shares of its common stock from time to time through the broker dealer subsidiary, as agent. The broker dealer receives a commission equal to 1% of the sales price of all shares sold under the agreement. In addition, under the terms of the Sales Agency Financing Agreement and forward sale agreement, Westar Energy may from time to time enter into one or more forward sale transactions with the bank, as forward purchaser, and the bank will borrow shares of Westar Energy's common stock from third parties and sell them through its broker dealer. Westar Energy must settle the forward sale transactions within a year of the date each transaction is entered. As of December 31, 2010, Westar Energy had entered into forward sale transactions with respect to an aggregate of approximately 5.4 million shares of common stock. As partial settlement of the forward sale transactions, Westar Energy delivered approximately 0.5 million shares of common stock for proceeds of $10.4 million on October 14, 2010. On December 20, 2010, Westar Energy delivered approximately 0.7 million additional shares for proceeds of $16.0 million as partial settlement of the forward sale transactions. Assuming physical share settlement of the approximately 4.2 million remaining shares of common stock at December 31, 2010, Westar Energy would have received aggregate proceeds of approximately $94.0 million, net of commission, based on an average forward price of $22.16 per share.

On February 15, 2011, Westar Energy delivered approximately 1.1 million shares of common stock and received proceeds of $25.8 million as partial settlement of the forward sale transactions discussed above.

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

In 2008, Westar Energy also completed a forward sale agreement entered into in November 2007 by delivering 5.1 million shares of common stock for proceeds of $123.0 million.

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

Cash Flows from Operating Activities

Operating activities provided $607.7 million of cash in 2010 compared with cash provided from operating activities of $478.9 million during 2009. This increase was due primarily to our having received $237.2 million more in customer receipts and our having received $27.1 million more in net tax refunds. With the consolidation of the VIEs discussed in Note 17 of the Notes to Consolidated Financial Statements, "Variable Interest Entities," a portion of lease payments previously reported as operating cash flows is now reported as financing cash flows, which resulted in about a $23.0 million increase in operating cash flows. In addition, we contributed $16.2 million less to the Westar Energy pension trust, Westar Energy post-retirement benefit plan and Wolf Creek pension trust; and during 2009, we paid $16.2 million more for our share of Wolf Creek's refueling outage. Partially offsetting these increases was our having paid in 2010 $94.7 million more for fuel and purchased power and $61.9 million more for interest on COLI policies, which was the result of a policy change in the second quarter of 2009 under which we no longer pay interest on such policies in advance.

Operating activities provided $478.9 million of cash in the year ended December 31, 2009, compared with cash provided from operating activities of $274.9 million during 2008. Principal contributors to the increase were our having paid $418.9 million less for fuel and purchased power and $50.5 million less for interest on our COLI policies. Partially offsetting increases were our having received $233.3 million less in customer receipts during 2009 due primarily to lower cash receipts from our wholesale customers, which more than offset higher cash receipts from our retail customers and our having paid $42.1 million more in interest on debt.

Cash Flows used in Investing Activities

Our principal use of cash for investing purposes relates to growing and improving our utility plant. The utility business is capital intensive and requires significant ongoing investment in plant. We invested $540.1 million in 2010, $555.6 million in 2009 and $919.0 million in 2008 in additions to property, plant and equipment. The decrease from 2008 to 2009 was due principally to the completion of air quality improvements to power plants, wind generation projects, transmission projects and the construction of Emporia Energy Center, which required significant amounts of cash in 2008.

Cash Flows (used in) from Financing Activities

Financing activities used $54.6 million of cash in 2010. We used cash to pay $129.1 million in dividends, repay $30.3 million of long-term debt including VIEs and repay $16.1 million of short-term debt. Borrowings from COLI provided $74.1 million and proceeds from the issuance of common stock provided $54.7 million.

We received net cash flows from financing activities of $97.2 million in 2009. Proceeds from the issuance of long-term debt provided $347.5 million and proceeds from short-term debt provided $67.9 million. We used cash to repay $196.8 million of long-term debt and to pay $122.9 million in dividends.

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

Cash Flows used in Investing Activities of Discontinued Operations

In 2009, we paid Protection One, Inc. $22.8 million for its share of the net tax benefit related to the net operating loss carryforward arising from our sale of that company.

Future Cash Requirements

Our business requires significant capital investments. Through 2013, we expect to need cash primarily for utility construction programs designed to improve and expand facilities related to providing electric service, which include, but are not limited to, expenditures for environmental improvements at our coal-fired power plants, new transmission lines and other improvements to our power plants, transmission and distribution lines, and equipment. We expect to meet these cash needs with internally generated cash, borrowings under Westar Energy's revolving credit facilities and through the issuance of securities in the capital markets.

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

On January 25, 2010, we announced a settlement with the DOJ of a pending lawsuit over allegations regarding environmental air regulations. The settlement was filed with the court, seeking its approval, and on March 26, 2010, the court entered an order approving the settlement. The settlement requires that we install an SCR on one of the three JEC coal units by the end of 2014. We estimate the cost of this to be approximately $240.0 million. This amount could change materially depending on final engineering and design. Depending on the NOx emission reductions attained by the single SCR and attainable through the installation of other controls on the other two JEC coal units, we may have to install an SCR on another JEC unit by the end of 2016, if needed to meet NOx reduction targets. Recovery of costs to install these systems is subject to the approval of our regulators. We believe these costs are appropriate for inclusion in the prices we are allowed to charge our customers. We will also invest $5.0 million over six years in environmental mitigation projects that we will own. In 2009, we recorded as part of the settlement $1.0 million for environmental mitigation projects that will be owned by a qualifying third party and a $3.0 million civil penalty.

Capital expenditures for 2010 and anticipated capital expenditures, including costs of removal, for 2011 through 2013 are shown in the following table.

	Actual 2010	2011	2012	2013
		(In Thousands)		
Generation:				
Replacements and other	$ 83,409	$130,400	$146,400	$150,600
Environmental	111,671	244,100	371,100	349,400
Nuclear fuel	35,267	25,100	30,100	41,700
Transmission (a)	197,316	192,700	161,300	164,100
Distribution:				
Replacements, new customers and other	78,658	95,900	102,200	106,400
Smart grid (b)	10,295	13,600	—	—
Other	23,460	19,800	15,000	11,000
Total capital expenditures	$540,076	$721,600	$826,100	$823,200

(a) In 2011, 2012 and 2013, we plan to incur additional expenditures related to our Prairie Wind Transmissionjoint venture of $2.7 million, $22.5 million and $13.8 million, respectively.

(b) Net of DOE matching grant.

We prepare these estimates for planning purposes and revise them from time to time. Actual expenditures will differ, perhaps materially, from our estimates due to changing environmental requirements, changing costs, delays in engineering, construction or permitting, changes in the availability and cost of capital, and other factors discussed in “Item 1A. Risk Factors.” We and our generating plant co-owners periodically evaluate these estimates and this may result in frequent and possibly material changes in actual costs. In addition, these amounts do not include any estimates for potentially new environmental requirements.

Over the next several years, we will also need significant amounts of cash to meet our long-term debt obligations. The principal amounts of our long-term debt maturities as of December 31, 2010, are as follows.

Year	Long-term debt	Long-term debt of VIEs
	(In Thousands)	
2011	$ 61	$ 30,155
2012	—	28,118
2013	—	25,941
2014	250,000	27,479
Thereafter	2,245,313	194,203
Total maturities	$ 2,495,374	$ 305,896

Pension Obligation

In accordance with a September 2009 KCC order, we expect to fund our pension plan each year at least to a level equal to our current year pension expense. We must also meet minimum funding requirements under the Employee Retirement Income Security Act, as amended by the Pension Protection Act. We may contribute additional amounts from time to time as deemed appropriate.

We contributed to our pension trust $22.4 million in 2010 and $37.3 million in 2009. We expect to contribute approximately $49.3 million in 2011. In 2010 and 2009, we also funded $6.0 million and $7.3 million, respectively, of Wolf Creek’s pension plan contributions. In 2011, we expect to fund $11.0 million of Wolf Creek’s pension plan contributions. See Notes 11 and 12 of the Notes to Consolidated Financial Statements, “Employee Benefit Plans” and “Wolf Creek Employee Benefit Plans,” for additional discussion of Westar Energy and Wolf Creek benefit plans, respectively.

OFF-BALANCE SHEET ARRANGEMENTS

As discussed under “—Common Stock Issuance” above and in Note 16 of the Notes to Consolidated Financial Statements, “Common and Preferred Stock,” Westar Energy entered into two separate forward sale agreements with banks in 2010. The forward sale agreements are off-balance sheet arrangements. We also have off-balance sheet arrangements in the form of operating leases and letters of credit entered into in the ordinary course of business. We did not have any additional off-balance sheet arrangements as of December 31, 2010. For additional information on operating leases, see Note 18 of the Notes to Consolidated Financial Statements, “Leases.” See “—Commercial Commitments” below for additional information regarding our letters of credit.

CONTRACTUAL OBLIGATIONS AND COMMERCIAL COMMITMENTS

In the course of our business activities, we enter into a variety of contracts and commercial commitments. Some of these result in direct obligations reflected on our consolidated balance sheets while others are commitments, some firm and some based on uncertainties, not reflected in our underlying consolidated financial statements. The amounts listed below include on-going needs for which contractual obligations existed as of December 31, 2010.

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Contractual Cash Obligations

The following table summarizes the projected future cash payments for our contractual obligations existing as of December 31, 2010.

	Total	2011	2012 - 2013	2014 - 2015	Thereafter
			(In Thousands)		
Long-term debt (a)	$2,495,374	$ 61	$ —	$ 250,000	$2,245,313
Long-term debt of VIEs (a)	305,896	30,155	54,059	55,411	166,271
Interest on long-term debt (b)	2,327,742	148,430	296,860	281,860	1,600,592
Interest on long-term debt of VIEs	98,483	18,168	30,105	22,614	27,596
Adjusted long-term debt	5,227,495	196,814	381,024	609,885	4,039,772
Pension and post-retirement benefit expected contributions (c)	71,249	71,249	—	—	—
Capital leases (d)	10,571	2,110	4,121	3,183	1,157
Operating leases (e)	78,916	12,940	26,165	17,875	21,936
Other obligations of VIEs (f)	22,584	1,881	5,723	2,114	12,866
Fossil fuel (g)	1,663,199	372,496	688,223	180,583	421,897
Nuclear fuel (h)	323,252	13,366	57,130	37,668	215,088
Unconditional purchase obligations	427,724	268,496	124,064	35,164	—
Unrecognized income tax benefits including interest (i)	118	118	—	—	—
Total contractual obligations, including adjusted long-term debt	$7,825,108	$939,470	$ 1,286,450	$ 886,472	$4,712,716

(a) See Note 9 of the Notes to Consolidated Financial Statements, “Long-Term Debt,” for individual long-term debt maturities.
(b) We calculate interest on our variable rate debt based on the effective interest rates as of December 31, 2010.
(c) Our contribution amounts for future periods are not yet known. See Notes 11 and 12 of the Notes to Consolidated Financial Statements, “Employee Benefit Plans” and “Wolf Creek Employee Benefit Plans,” for additional information regarding pension and post-retirement benefits.
(d) Includes principal and interest on capital leases.
(e) Includes leases for operating facilities, operating equipment, office space, office equipment, vehicles and railcars as well as other miscellaneous commitments.
(f) See Note 17 of the Notes to Consolidated Financial Statements, “Variable Interest Entities,” for additional information on VIEs.
(g) Coal and natural gas commodity and transportation contracts.
(h) Uranium concentrates, conversion, enrichment, fabrication and spent nuclear fuel disposal.
(i) We have an additional $2.1 million of unrecognized income tax benefits, including interest, that are not included in this table because we cannot reasonably estimate the timing of the cash payments to taxing authorities assuming those unrecognized income tax benefits are settled at the amounts accrued as of December 31, 2010.

Commercial Commitments

Our commercial commitments as of December 31, 2010, consist of outstanding letters of credit that expire in 2011, some of which automatically renew annually. The letters of credit are comprised of $8.6 million related to worker’s compensation, $6.2 million related to new transmission projects, $2.9 million related to energy marketing and trading activities, and $4.4 million related to other operating activities, for a total outstanding balance of $22.1 million.

OTHER INFORMATION

Changes in Prices

In February 2011, we filed an application with the KCC to adjust our prices to include updated transmission costs as reflected in our transmission formula rate discussed below. If approved, we estimate that the new prices will increase our annual retail revenues by $14.6 million. We expect the KCC to issue an order on our request in March 2011.

On October 29, 2010, the KCC issued an order, effective November 2010, allowing us to recover in our prices $5.8 million of previously deferred amounts associated with various energy efficiency programs.

On October 15, 2010, we posted our updated transmission formula rate which includes projected 2011 transmission capital expenditures and operating costs. The updated rate was effective January 1, 2011, and is expected to increase our annual transmission revenues by $15.9 million.

On June 11, 2010, the KCC issued a final order approving an adjustment to our prices that we made earlier in 2010. The adjustment included updated transmission costs as reflected in our transmission formula rate discussed below. The new prices were effective March 16, 2010, and are expected to increase our annual retail revenues by $6.4 million.

On May 25, 2010, the KCC issued an order allowing us to adjust our prices to include costs associated with environmental investments made in 2009. The new prices were effective June 1, 2010, and are expected to increase our annual retail revenues by $13.8 million.

On January 27, 2010, the KCC issued an order allowing us to adjust our prices to include costs associated with investments in natural gas and wind generation facilities. The new prices were effective February 2010 and are expected to increase our annual retail revenues by $17.1 million.

Our transmission formula rate that includes projected 2010 transmission capital expenditures and operating costs became effective January 1, 2010, and was expected to increase our annual transmission revenues by $16.8 million. The transmission formula rate provides the basis for our annual request with the KCC to adjust our retail prices to include updated transmission costs as noted above.

New Financial Regulation

On July 21, 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) was signed into law. Although the Dodd-Frank Act is focused primarily on the regulation and oversight of financial institutions, it also calls for new regulation of the derivatives markets, including mandatory clearing of certain swaps, exchange trading, margin requirements and other transparency requirements, which could impact our operations and consolidated financial results. As the implementing regulations for the Dodd-Frank Act have not yet been finalized, we cannot predict what such impact might be. We will continue to evaluate the Dodd-Frank Act as more information becomes available.

Stock-Based Compensation

We use two types of restricted share units (RSUs) for our stock-based compensation awards; those with service requirements and those with performance measures. See Note 11 of the Notes to Consolidated Financial Statements, “Employee Benefit Plans,” for additional information. Total unrecognized compensation cost related to RSU awards with only service requirements was $4.8 million as of December 31, 2010, and we expect to recognize these costs over a remaining weighted-average period of 1.9 years. Total unrecognized compensation cost related to RSU awards with performance measures was $4.0 million as of December 31, 2010, and we expect to recognize these costs over a remaining weighted-average period of 1.6 years. There were no modifications of awards during the years ended December 31, 2010, 2009 or 2008.

New Accounting Pronouncements

We prepare our consolidated financial statements in accordance with GAAP for the United States of America. To address current issues in accounting, the FASB issued the following new accounting pronouncement that affected our accounting and disclosure.

Consolidation Guidance for Variable Interest Entities

In June 2009, the FASB amended the consolidation guidance for VIEs. The amended guidance requires a qualitative assessment rather than a quantitative assessment in determining the primary beneficiary of a VIE and significantly changes the criteria to consider in determining the primary beneficiary. Pursuant to the amended guidance, there is no exclusion, or "grandfathering," of VIEs that were not consolidated under prior guidance. This amended guidance was effective for annual reporting periods beginning after November 15, 2009. We adopted the guidance effective January 1, 2010, and, as a result, began consolidating certain VIEs that hold assets we lease. As a result, we added a significant amount of assets and liabilities to our consolidated balance sheets as discussed under "Operating Results – Financial Condition" above. In addition, such consolidation did not impact our net income and will not impact our net income going forward since net income of the VIEs is separately identified on our consolidated statements of income as net income attributable to noncontrolling interests. See Note 17 of the Notes to Consolidated Financial Statements, "Variable Interest Entities," for additional information.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Commodity Price Risk

We engage in both financial and physical trading with the goal of managing our commodity price risk, enhancing system reliability and increasing profits. We procure and trade electricity, coal, natural gas and other energy-related products by utilizing energy commodity contracts and a variety of financial instruments, including futures contracts, options and swaps.

Within our energy trading portfolio, we may establish certain positions intended to economically hedge a portion of physical sale or purchase contracts and we may enter into certain positions attempting to take advantage of market trends and conditions. We use the term economic hedge to mean a strategy intended to manage risks of volatility in prices or rate movements on selected assets, liabilities or anticipated transactions by creating a relationship in which gains or losses on derivative instruments are expected to offset the losses or gains on the assets, liabilities or anticipated transactions exposed to such market risks. At the time we enter into these transactions, we are unable to determine the hedge value until the agreements are actually settled. Our future exposure to changes in prices will be dependent on the market prices and the extent and effectiveness of any economic hedging arrangements into which we enter. Additionally, 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 net open positions, we are exposed to the risk that changing market prices could have a material adverse impact on our consolidated financial results.

We use various types of fuel, including coal, natural gas, uranium, diesel and oil, to operate our plants and purchase power to meet customer demand. We are exposed to market risks from commodity price changes for electricity and other energy-related products and interest rates that could affect our consolidated financial results, including cash flows. We attempt to manage our exposure to these market risks through our regular operating and financing activities and, when we deem appropriate, we economically hedge a portion of these risks through the use of derivative financial instruments for non-trading purposes.

Factors that affect our commodity price exposure are the quantity and availability of fuel used for generation, the availability of our power plants and the quantity of electricity customers consume. Quantities of fossil fuel we use to generate electricity fluctuate from period to period based on availability, price and deliverability of a given fuel type, as well as planned and unscheduled outages at our generating plants that use fossil fuels. Our commodity price exposure is also affected by our nuclear plant refueling and maintenance schedule. Our customers’ electricity usage also varies based on weather, the economy and other factors.

The wholesale power and fuel markets are volatile. This volatility impacts our costs of purchased power, fuel costs for our power plants and our participation in energy markets. We trade various types of fuel primarily to reduce exposure related to the volatility of commodity prices. A significant portion of our coal requirements is purchased under long-term contracts to hedge much of the fuel exposure for customers. 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.

One way by which we manage and measure the commodity price risk of our trading portfolio is by using a variance/covariance value-at-risk (VaR) model. In addition to VaR, we employ additional risk control processes such as stress testing, daily loss limits, credit limits and position limits. We expect to use similar control processes in the future. The use of VaR requires assumptions, including the selection of a confidence level and a measure of volatility associated with potential losses and the estimated holding period. We express VaR as a potential dollar loss based on a 95% confidence level using a one-day holding period and a 20-day historical observation period. It is possible that actual results may differ markedly from assumptions. Accordingly, VaR may not accurately reflect our levels of exposures. The energy trading and market-based wholesale portfolio VaR amounts for 2010 and 2009 were as follows:

	2010	2009
	(In Thousands)	
High	$ 613	$ 914
Low	26	43
Average	121	280

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

Credit Risk

We are exposed to counterparty default risk with our retail, wholesale and energy marketing activities, including participation in RTOs. Such credit risk is associated with the financial condition of counterparties, product location (basis) pricing differentials, physical liquidity constraints 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 intended to reduce our overall credit risk. We also employ additional credit risk control mechanisms that we believe are appropriate, such as requiring counterparties to issue letters of credit or parental guarantees in our favor and entering into master netting agreements with counterparties that allow for offsetting exposures.

Certain of our derivative instruments contain collateral provisions subject to credit agency ratings of our senior unsecured debt. If our senior unsecured debt ratings were to decrease or fall below investment grade, the counterparties to the derivative instruments, pursuant to the provisions, could require collateralization on derivative instruments. The aggregate fair value of all derivative instruments with objective credit-risk-related contingent features that were in a liability position as of December 31, 2010 and 2009, was $1.6 million and $1.4 million, respectively, for which we had posted no collateral. If all credit-risk-related contingent features underlying these agreements had been triggered as of December 31, 2010 and 2009, we would have been required to provide to our counterparties $1.6 million and $0.1 million, respectively, of additional collateral after taking into consideration the offsetting impact of derivative assets and net accounts receivable.

Interest Rate Risk

We have entered into numerous fixed and variable rate debt obligations. For details, see Note 9 of the Notes to Consolidated Financial Statements, “Long-Term Debt.” We manage our interest rate risk related to these debt obligations by limiting our variable interest rate exposure, utilizing various maturity dates and entering into treasury yield hedge transactions. We may also use other financial derivative instruments, such as interest rate swaps. We compute and present information about the sensitivity to changes in interest rates for variable rate debt and current maturities of fixed rate debt by assuming a 100 basis point change in the current interest rates applicable to such debt over the remaining time the debt is outstanding.

We had approximately $378.9 million of variable rate debt and current maturities of fixed rate debt as of December 31, 2010. A 100 basis point change in interest rates applicable to this debt would impact income before income taxes on an annualized basis by approximately $3.6 million. As of December 31, 2010, we had $121.9 million of variable rate bonds insured by bond insurers. Interest rates payable under these bonds are normally set through periodic auctions. However, conditions in the credit markets over the past few years caused a dramatic reduction in the demand for auction bonds, which lead to failed auctions. The contractual provisions of these securities set forth an indexing formula method by which interest will be paid in the event of an auction failure. Depending on the level of these reference indices, our interest costs may be higher or lower than what they would have been had the securities been auctioned successfully. Additionally, should insurers of those bonds experience a decrease in their credit ratings, such event would most likely increase our borrowing costs. Furthermore, a decline in interest rates generally can serve to increase our pension and other post-retirement benefit obligations and negatively affect investment returns.

As of December 31, 2010, we had recorded a $7.7 million gain on treasury yield hedge transactions with a total notional amount of $100.0 million. These transactions are measured at fair value by estimating the net present value of a series of payments using models with inputs such as the spread between the 30-year U.S. Treasury bill yield and the contracted, fixed yield. As of December 31, 2010, a hypothetical 100 basis point decrease in the 30-year U.S. Treasury bill yield would decrease the fair value of these transactions by approximately $16.6 million, with a corresponding increase to regulatory assets net of regulatory liabilities. The impact of a change in market interest rates on these transactions at a point in time is not necessarily representative of the results that will be realized when such transactions are settled. Net gains or losses, to the extent realized, will be amortized to interest expense over the life of the respective debt issuance.

Security Price Risk

We maintain trust funds, as required by the NRC and Kansas statue, to fund certain costs of nuclear plant decommissioning. As of December 31, 2010, investments in the NDT fund were allocated 65% to equity securities, 33% to debt securities, 2% to real estate securities and less than 1% to cash and cash equivalents. The fair value of these funds was $127.0 million as of December 31, 2010, and $112.3 million as of December 31, 2009. Changes in interest rates and/or other market changes resulting in a 10% decrease in the value of the equity, debt and real estate securities would have resulted in a $12.7 million decrease in the value of the NDT fund as of December 31, 2010.

We also maintain a trust to fund non-qualified retirement benefits. As of December 31, 2010, these funds were comprised of 67% equity securities and 33% debt securities. The fair value of these funds was $39.4 million as of December 31, 2010, and $34.6 million as of December 31, 2009. Changes in interest rates and/or other market changes resulting in a 10% decrease in the value of the equity and debt securities would have resulted in a $3.9 million decrease in the value of the trust as of December 31, 2010.

By maintaining diversified portfolios of securities, we seek to maximize the returns to fund the aforementioned obligations within acceptable risk tolerances, including interest rate risk. However, debt and equity securities in the portfolios are exposed to price fluctuations in the capital markets. If the value of the securities diminishes, the cost of funding the obligations rises. We actively monitor the portfolios by benchmarking the performance of the investments against relevant indices and by maintaining and periodically reviewing the asset allocations in relation to established policy targets. Our exposure to security price risk related to the NDT fund is, in part, mitigated because we are currently allowed to recover decommissioning costs in the prices we charge our customers.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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SCHEDULES OMITTED

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

I, III, IV and V.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

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

We assessed the effectiveness of our internal control over financial reporting as of December 31, 2010. In making this assessment, we used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control-Integrated Framework. Based on the assessment, we concluded that, as of December 31, 2010, our internal control over financial reporting is effective based on those criteria. Our independent registered public accounting firm has issued an audit report on the company's internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the internal control over financial reporting of Westar Energy, Inc. and subsidiaries (the "Company") as of December 31, 2010, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying management's report on internal control over financial reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2010 of the Company and our report dated February 24, 2011 expressed an unqualified opinion on those financial statements and financial statement schedule and included an explanatory paragraph related to the adoption of a new accounting standard in 2010.

/s/ Deloitte & Touche LLP

Kansas City, Missouri
February 24, 2011

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Westar Energy Inc. and subsidiaries (the "Company") as of December 31, 2010 and 2009, and the related consolidated statements of income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2010. Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Westar Energy, Inc. and subsidiaries as of December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

As discussed in Note 17 to the consolidated financial statements, the Company adopted a new accounting standard with respect to the consolidation of variable interest entities effective January 1, 2010.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2010, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 24, 2011 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Kansas City, Missouri
February 24, 2011

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WESTAR ENERGY, INC.
CONSOLIDATED BALANCE SHEETS
(Dollars in Thousands; except par values)

	As of December 31, 2010	2009
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 928	$ 3,860
Accounts receivable, net of allowance for doubtful accounts of $5,729 and $5,231, respectively	227,700	216,186
Inventories and supplies, net	206,867	193,831
Energy marketing contracts	13,005	33,159
Taxes receivable	16,679	45,200
Deferred tax assets	30,248	7,927
Prepaid expenses	12,413	11,830
Regulatory assets	73,480	97,220
Other	20,289	20,269
Total Current Assets	601,609	629,482
PROPERTY, PLANT AND EQUIPMENT, NET	5,964,439	5,771,740
PROPERTY, PLANT AND EQUIPMENT OF VARIABLE INTEREST ENTITIES, NET (See Note 17)	345,037	—
OTHER ASSETS:		
Regulatory assets	787,585	758,538
Nuclear decommissioning trust	126,990	112,268
Energy marketing contracts	9,472	10,653
Other	244,506	242,802
Total Other Assets	1,168,553	1,124,261
TOTAL ASSETS	$8,079,638	$7,525,483
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Current maturities of long-term debt	$ 61	$ 1,345
Current maturities of long-term debt of variable interest entities (See Note 17)	30,155	—
Short-term debt	226,700	242,760
Accounts payable	187,954	112,211
Accrued taxes	45,534	46,931
Energy marketing contracts	9,670	39,161
Accrued interest	77,771	76,955
Regulatory liabilities	28,284	39,745
Other	176,717	123,370
Total Current Liabilities	782,846	682,478
LONG-TERM LIABILITIES:		
Long-term debt, net	2,490,871	2,490,734
Long-term debt of variable interest entities, net (See Note 17)	278,162	—
Obligation under capital leases	7,514	109,300
Deferred income taxes	1,102,625	964,461
Unamortized investment tax credits	101,345	127,777
Regulatory liabilities	135,754	100,963
Deferred regulatory gain from sale-leaseback	97,541	108,532
Accrued employee benefits	483,769	433,561
Asset retirement obligations	125,999	119,519
Energy marketing contracts	10	210
Other	59,364	117,720
Total Long-Term Liabilities	4,882,954	4,572,777
COMMITMENTS AND CONTINGENCIES (See Notes 13 and 15)		
TEMPORARY EQUITY (See Note 11)	3,465	3,443
EQUITY:		
Westar Energy Shareholders' Equity:		
Cumulative preferred stock, par value $100 per share; authorized 600,000 shares; issued and outstanding 214,363 shares	21,436	21,436
Common stock, par value $5 per share; authorized 150,000,000 shares; issued and outstanding 112,128,068 shares and 109,072,000 shares, respectively	560,640	545,360
Paid-in capital	1,398,580	1,339,790
Retained earnings	423,647	360,199
Total Westar Energy Shareholders' Equity	2,404,303	2,266,785
Noncontrolling Interests	6,070	—
Total Equity	2,410,373	2,266,785
TOTAL LIABILITIES AND EQUITY	$8,079,638	$7,525,483

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

WESTAR ENERGY, INC.
CONSOLIDATED STATEMENTS OF INCOME
(Dollars in Thousands, Except Per Share Amounts)

	Year Ended December 31,		
	2010	2009	2008
REVENUES	$ 2,056,171	$ 1,858,231	$ 1,838,996
OPERATING EXPENSES:			
Fuel and purchased power	583,361	534,864	694,348
Operating and maintenance	520,409	516,930	471,838
Depreciation and amortization	271,937	251,534	203,738
Selling, general and administrative	207,607	199,961	184,427
Total Operating Expenses	1,583,314	1,503,289	1,554,351
INCOME FROM OPERATIONS	472,857	354,942	284,645
OTHER INCOME (EXPENSE):			
Investment earnings (losses)	7,026	12,658	(10,453)
Other income	5,369	7,128	29,658
Other expense	(16,655)	(17,188)	(15,324)
Total Other (Expense) Income	(4,260)	2,598	3,881
Interest expense	174,941	157,360	106,450
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	293,656	200,180	182,076
Income tax expense	85,032	58,850	3,936
INCOME FROM CONTINUING OPERATIONS	208,624	141,330	178,140
Results of discontinued operations, net of tax	—	33,745	—
NET INCOME	208,624	175,075	178,140
Less: Net income attributable to noncontrolling interests	4,728	—	—
NET INCOME ATTRIBUTABLE TO WESTAR ENERGY	203,896	175,075	178,140
Preferred dividends	970	970	970
NET INCOME ATTRIBUTABLE TO COMMON STOCK	$ 202,926	$ 174,105	$ 177,170
BASIC AND DILUTED EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING ATTRIBUTABLE TO WESTAR ENERGY (see Note 2):			
Basic earnings available from continuing operations	$ 1.81	$ 1.28	$ 1.69
Discontinued operations, net of tax	—	0.30	—
Basic earnings per common share	$ 1.81	$ 1.58	$ 1.69
Diluted earnings available from continuing operations	$ 1.80	$ 1.28	$ 1.69
Discontinued operations, net of tax	—	0.30	—
Diluted earnings per common share	$ 1.80	$ 1.58	$ 1.69
Average equivalent common shares outstanding	111,629,292	109,647,689	103,958,414
DIVIDENDS DECLARED PER COMMON SHARE	$ 1.24	$ 1.20	$ 1.16
AMOUNTS ATTRIBUTABLE TO WESTAR ENERGY:			
Income from continuing operations	$ 203,896	$ 141,330	$ 178,140
Results of discontinued operations, net of tax	—	33,745	—
Net income	$ 203,896	$ 175,075	$ 178,140

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

WESTAR ENERGY, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Dollars in Thousands)

	Year Ended December 31,		
	2010	2009	2008
CASH FLOWS FROM (USED IN) OPERATING ACTIVITIES:			
Net income	$ 208,624	$ 175,075	$ 178,140
Discontinued operations, net of tax	—	(33,745)	—
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	271,937	251,534	203,738
Amortization of nuclear fuel	25,089	16,161	14,463
Amortization of deferred regulatory gain from sale-leaseback	(5,495)	(5,495)	(5,495)
Amortization of corporate-owned life insurance	20,650	22,116	18,920
Non-cash compensation	11,373	5,133	4,696
Net changes in energy marketing assets and liabilities	(1,284)	8,972	(7,018)
Accrued liability to certain former officers	2,675	2,296	(1,449)
Gain on sale of utility plant and property	—	—	(1,053)
Net deferred income taxes and credits	120,169	46,447	35,261
Stock-based compensation excess tax benefits	(641)	(448)	(561)
Allowance for equity funds used during construction	(3,104)	(5,031)	(18,284)
Changes in working capital items:			
Accounts receivable	(11,434)	(17,159)	(3,331)
Inventories and supplies	(12,266)	10,466	(11,764)
Prepaid expenses and other	8,475	(10,635)	(52,615)
Accounts payable	30,330	(15,115)	(73,971)
Accrued taxes	27,565	30,493	27,938
Other current liabilities	(80,660)	13,572	(5,732)
Changes in other assets	(42,544)	73,784	29,389
Changes in other liabilities	38,243	(89,516)	(56,382)
Cash Flows from Operating Activities	607,702	478,905	274,890
CASH FLOWS FROM (USED IN) INVESTING ACTIVITIES:			
Additions to property, plant and equipment	(540,076)	(555,637)	(918,958)
Investment in corporate-owned life insurance	(19,162)	(17,724)	(18,720)
Purchase of securities within trust funds	(192,350)	(64,016)	(210,599)
Sale of securities within trust funds	191,603	61,096	221,613
Proceeds from investment in corporate-owned life insurance	2,204	1,748	27,320
Proceeds from sale of plant and property	—	—	4,295
Proceeds from federal grant	3,180	—	—
Investment in affiliated company	(280)	(818)	—
Other investing activities	(1,164)	2,920	(11,388)
Cash Flows used in Investing Activities	(556,045)	(572,431)	(906,437)
CASH FLOWS FROM (USED IN) FINANCING ACTIVITIES:			
Short-term debt, net	(16,060)	67,860	(5,100)
Proceeds from long-term debt	—	347,507	544,715
Retirements of long-term debt	(1,695)	(196,821)	(101,311)
Retirements of long-term debt of variable interest entities	(28,610)	—	—
Repayment of capital leases	(2,981)	(10,190)	(9,820)
Borrowings against cash surrender value of corporate-owned life insurance	74,134	10,299	64,255
Repayment of borrowings against cash surrender value of corporate-owned life insurance	(3,430)	(3,531)	(28,634)
Stock-based compensation excess tax benefits	641	448	561
Issuance of common stock, net	54,651	4,587	293,621
Distributions to shareholders of noncontrolling interests	(2,093)	—	—
Cash dividends paid	(129,146)	(122,937)	(109,579)
Cash Flows (used in) from Financing Activities	(54,589)	97,222	648,708
CASH FLOWS USED IN INVESTING ACTIVITIES OF DISCONTINUED OPERATIONS:			
Payment of settlement to former subsidiary	—	(22,750)	—
Cash flows used in investing activities of discontinued operations	—	(22,750)	—
NET (DECREASE) INCREASE IN CASH AND CASH EQUIVALENTS	(2,932)	(19,054)	17,161
CASH AND CASH EQUIVALENTS:			
Beginning of period	3,860	22,914	5,753
End of period	$ 928	$ 3,860	$ 22,914

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

WESTAR ENERGY, INC.
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(Dollars in Thousands)

	Westar Energy Shareholders						
	Cumulative preferred stock	Common stock	Paid-in capital	Retained earnings	Accumulated other comprehensive income (loss)	Noncontrolling interests	Total equity
Balance at December 31, 2007	$ 21,436	$477,316	$1,085,099	$ 264,477	$ 152	$ —	$1,848,480
Net income	—	—	—	178,140	—	—	178,140
Issuance of common stock, net	—	64,240	239,316	—	—	—	303,556
Preferred dividends	—	—	—	(970)	—	—	(970)
Dividends on common stock	—	—	—	(123,107)	—	—	(123,107)
Reclass to temporary equity	—	—	1,802	—	—	—	1,802
Amortization of restricted stock	—	—	3,941	—	—	—	3,941
Stock compensation and tax benefit	—	—	(3,767)	—	—	—	(3,767)
Adjustment to retained earnings – Pension and other post-retirement benefit plans	—	—	—	(495)	—	—	(495)
Adjustment to retained earnings – Fair value option	—	—	—	152	(152)	—	—
Balance at December 31, 2008	21,436	541,556	1,326,391	318,197	—	—	2,207,580
Net income	—	—	—	175,075	—	—	175,075
Issuance of common stock, net	—	3,804	10,569	—	—	—	14,373
Preferred dividends	—	—	—	(970)	—	—	(970)
Dividends on common stock	—	—	—	(132,103)	—	—	(132,103)
Reclass to temporary equity	—	—	(20)	—	—	—	(20)
Amortization of restricted stock	—	—	4,524	—	—	—	4,524
Stock compensation and tax benefit	—	—	(1,674)	—	—	—	(1,674)
Balance at December 31, 2009	21,436	545,360	1,339,790	360,199	—	—	2,266,785
Net income	—	—	—	203,896	—	4,728	208,624
Issuance of common stock, net	—	15,280	50,759	—	—	—	66,039
Preferred dividends	—	—	—	(970)	—	—	(970)
Dividends on common stock	—	—	—	(139,478)	—	—	(139,478)
Reclass to temporary equity	—	—	(22)	—	—	—	(22)
Amortization of restricted stock	—	—	10,710	—	—	—	10,710
Stock compensation and tax benefit	—	—	(2,657)	—	—	—	(2,657)
Consolidation of noncontrolling interests	—	—	—	—	—	3,435	3,435
Distributions to shareholders of noncontrolling interests	—	—	—	—	—	(2,093)	(2,093)
Balance at December 31, 2010	$ 21,436	$560,640	$1,398,580	$ 423,647	$ —	$ 6,070	$2,410,373

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

WESTAR ENERGY, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. DESCRIPTION OF BUSINESS

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

We provide electric generation, transmission and distribution services to approximately 687,000 customers in Kansas. Westar Energy provides these services in central and northeastern Kansas, including the cities of Topeka, Lawrence, Manhattan, Salina and Hutchinson. Kansas Gas and Electric Company (KGE), Westar Energy’s wholly-owned subsidiary, provides these services in south-central and southeastern Kansas, including the city of Wichita. Both Westar Energy and KGE conduct business using the name Westar Energy. Our corporate headquarters is located at 818 South Kansas Avenue, Topeka, Kansas 66612.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation

We prepare our consolidated financial statements in accordance with GAAP for the United States of America. Our consolidated financial statements include all operating divisions, majority owned subsidiaries and variable interest entities (VIEs) of which we maintain a controlling interest or are the primary beneficiary reported as a single operating segment. Undivided interests in jointly-owned generation facilities are included on a proportionate basis. Intercompany accounts and transactions have been eliminated in consolidation.

Use of Management’s Estimates

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

Regulatory Accounting

We apply accounting standards that recognize the economic effects of rate regulation. Accordingly, we have recorded regulatory assets and liabilities when required by a regulatory order or based on regulatory precedent. See Note 3, “Rate Matters and Regulation,” for additional information regarding our regulatory assets and liabilities.

Cash and Cash Equivalents

We consider investments that are highly liquid and 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, and property, plant and equipment of VIEs at cost. For plant, cost includes contracted services, direct labor and materials, indirect charges for engineering and supervision and an allowance for funds used during construction (AFUDC). AFUDC represents the allowed cost of capital used to finance utility construction activity. We compute AFUDC by applying a composite rate to qualified construction work in progress. We credit to other income (for equity funds) and interest expense (for borrowed funds) the amount of AFUDC capitalized as construction cost on the accompanying consolidated statements of income as follows:

	Year Ended December 31,		
	2010	2009	2008
	(Dollars In Thousands)		
Borrowed funds	$4,295	$4,857	$20,536
Equity funds	3,104	5,031	18,284
Total	$7,399	$9,888	$38,820
Average AFUDC Rates	2.6%	4.2%	6.4%

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

Depreciation

We depreciate utility plant using a straight-line method. These rates are based on an average annual composite basis using group rates that approximated 2.9% in 2010, 3.0% in 2009 and 2.6% in 2008.

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

	Years
Fossil fuel generating facilities	7 to 69
Nuclear fuel generating facility	40 to 60
Wind generating facilities	19 to 20
Transmission facilities	15 to 65
Distribution facilities	21 to 70
Other	5 to 35

Nuclear Fuel

We record as property, plant and equipment our share of the cost of nuclear fuel used in the process of refinement, conversion, enrichment and fabrication. We reflect this at original cost and amortize such amounts to fuel expense based on the quantity of heat consumed during the generation of electricity, as measured in millions of British thermal units (MMBtu). The accumulated amortization of nuclear fuel in the reactor was $48.0 million as of December 31, 2010, and $22.9 million as of December 31, 2009. Cost of nuclear fuel charged to fuel and purchased power expense was $29.2 million in 2010, $20.1 million in 2009 and $18.3 million in 2008.

Cash Surrender Value of Life Insurance

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

	As of December 31,	
	2010	2009
	(In Thousands)	
Cash surrender value of policies	$ 1,280,615	$ 1,209,304
Borrowings against policies	(1,144,248)	(1,073,544)
Corporate-owned life insurance, net	$ 136,367	$ 135,760

We record as income increases in cash surrender value and death benefits. We offset against policy income the interest expense that we incur on policy loans. Income from death benefits is highly variable from period to period.

Revenue Recognition

Electricity Sales

We record revenue at the time we deliver electricity to customers. We determine the amounts delivered to individual customers through systematic monthly readings of customer meters. At the end of each month, we estimate how much electricity we have delivered since the prior meter reading and record the corresponding unbilled revenue.

Our unbilled revenue estimate is affected by factors including fluctuations in energy demand, weather, line losses and changes in the composition of customer classes. We had estimated unbilled revenue of $53.8 million as of December 31, 2010, and $56.6 million as of December 31, 2009.

Energy Marketing Contracts

We account for energy marketing derivative contracts under the fair value 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 certain fuel supply and electricity contracts, which we record as regulatory assets or regulatory liabilities, we include the net change in fair value in revenues on our consolidated statements of income. We record the unrealized gains and losses as energy marketing long-term or short-term assets and liabilities on our consolidated balance sheets as appropriate. We use quoted market prices to value our energy marketing derivative contracts when such data are available. When market prices are not readily available or determinable, we use alternative approaches, such as model pricing. The prices we use to value these transactions reflect our best estimate of the fair value of these contracts. Results actually achieved from these activities could vary materially from intended results and could affect our consolidated financial results.

Normal Purchases and Normal Sales Exception

Determining whether a contract qualifies for the normal purchases and normal sales exception requires that we exercise judgment on whether the contract will physically deliver and requires that we ensure compliance with all of the associated qualification and documentation requirements. Revenues and expenses on contracts that qualify as normal purchases and normal sales are recognized when the underlying physical transaction is completed. Contracts which qualify for the normal purchases and normal sales exception are those for which physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time and price is not tied to an unrelated underlying derivative.

Allowance for Doubtful Accounts

We determine our allowance for doubtful accounts based on the age of our receivables. We charge receivables off when they are deemed uncollectible, which is based on a number of factors including specific facts surrounding an account and management's judgment.

Income Taxes

We use the asset and liability method of accounting for income taxes. Under this method, we recognize deferred tax assets and liabilities for the future tax consequences attributable to temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. We recognize the future tax benefits to the extent that realization of such benefits is more likely than not. We amortize deferred investment tax credits over the lives of the related properties as required by tax laws and regulatory practices. We recognize production tax credits in the year that electricity is generated to the extent that realization of such benefits is more likely than not.

We record deferred tax assets to carry forward into future periods capital losses, operating losses and tax credits. However, when we believe based on available evidence that we do not, or will not, have sufficient future capital gains or taxable income in the appropriate taxing jurisdiction to realize the entire benefit during the applicable carryforward period, we record a valuation allowance against the deferred tax asset.

The application of income tax law is complex. Laws and regulations in this area are voluminous and often ambiguous. Accordingly, we must make judgments regarding income tax exposure. Interpretations of and guidance surrounding income tax laws and regulations change over time. As a result, changes in our judgments can materially affect amounts we recognize in our consolidated financial statements. See Note 10, "Taxes," for additional detail on our accounting for income taxes.

Sales Taxes

We account for the collection and remittance of sales tax on a net basis. As a result, we do not reflect them in our consolidated statements of income.

Earnings Per Share

We have participating securities related to unvested restricted share units (RSUs) with nonforfeitable rights to dividend equivalents that receive dividends as declared on an equal basis with common shares. As a result, we apply the two-class method of computing basic and diluted earnings per share (EPS).

Under the two-class method, we reduce net income attributable to common stock by the amount of dividends declared in the current period. We allocate the remaining earnings to common stock and RSUs to the extent that each security may share in earnings as if all of the earnings for the period had been distributed. We determine the total earnings allocated to each security by adding together the amount allocated for dividends and the amount allocated for a participation feature. To compute basic EPS, we divide the earnings allocated to common stock by the weighted average number of common shares outstanding. Diluted EPS includes the effect of potential issuances of common shares resulting from our forward sale agreements, RSUs that do not have nonforfeitable rights to dividend equivalents and stock options. We compute the dilutive effect of potential issuances of common shares using the treasury stock method.

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The following table reconciles our basic and diluted EPS from income from continuing operations.

	Year Ended December 31, 2010	2009	2008
	(Dollars In Thousands, Except Per Share Amounts)		
Income from continuing operations	$ 208,624	$ 141,330	$ 178,140
Less: Income attributable to noncontrolling interests	4,728	—	—
Income from continuing operations attributable to Westar Energy	203,896	141,330	178,140
Less: Preferred dividends	970	970	970
Income from continuing operations allocated to RSUs	1,259	541	1,346
Income from continuing operations attributable to common stock	$ 201,667	$ 139,819	$ 175,824
Weighted average equivalent common shares outstanding – basic	111,629,292	109,647,689	103,958,414
Effect of dilutive securities:			
Restricted share units	140,077	—	—
Forward sale agreements	245,496	—	—
Employee stock options	59	481	728
Weighted average equivalent common shares outstanding – diluted (a)	112,014,924	109,648,170	103,959,142
Earnings from continuing operations per common share, basic	$ 1.81	$ 1.28	$ 1.69
Earnings from continuing operations per common share, diluted	$ 1.80	$ 1.28	$ 1.69

(a) We did not have any antidilutive shares for the years ended December 31, 2010 and 2009. For the year ended December 31, 2008, potentially dilutive shares not included in the denominator because they are antidilutive totaled 21,300 shares.

Supplemental Cash Flow Information

	Year Ended December 31, 2010	2009	2008
	(In Thousands)		
CASH PAID FOR (RECEIVED FROM):			
Interest on financing activities, net of amount capitalized	$ 145,463	$144,964	$102,865
Interest on financing activities of VIEs (a)	20,191	—	—
Income taxes, net of refunds	(34,980)	(7,870)	(34,905)
NON-CASH INVESTING TRANSACTIONS:			
Property, plant and equipment additions	64,423	21,614	106,219
Property, plant and equipment additions of VIEs (a)	356,964	—	—
Jeffrey Energy Center (JEC) 8% leasehold interest (a)	(108,706)	—	—
NON-CASH FINANCING TRANSACTIONS:			
Issuance of common stock for reinvested dividends and compensation plans	18,777	12,168	11,263
Debt of VIEs (a)	337,951	—	—
Capital lease for JEC 8% leasehold interest (a)	(106,423)	—	—
Assets acquired through capital leases	910	2,818	4,583

(a) These transactions result from the consolidation of the VIEs discussed in Note 17, “Variable Interest Entities.”

New Accounting Pronouncements

We prepare our consolidated financial statements in accordance with GAAP for the United States of America. To address current issues in accounting, the Financial Accounting Standards Board (FASB) issued the following new accounting pronouncement that affected our accounting and disclosure.

Consolidation Guidance for Variable Interest Entities

In June 2009, the FASB amended the consolidation guidance for VIEs. The amended guidance requires a qualitative assessment rather than a quantitative assessment in determining the primary beneficiary of a VIE and significantly changes the criteria to consider in determining the primary beneficiary. Pursuant to the amended guidance, there is no exclusion, or "grandfathering," of VIEs that were not consolidated under prior guidance. This amended guidance was effective for annual reporting periods beginning after November 15, 2009. We adopted the guidance effective January 1, 2010, and, as a result, began consolidating certain VIEs that hold assets we lease. See Note 17, "Variable Interest Entities," for additional information.

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3. RATE MATTERS AND REGULATION

Regulatory Assets and Regulatory Liabilities

Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery in customer prices. Regulatory liabilities represent probable future reductions in revenue or refunds to customers through the price setting process. Regulatory assets and liabilities reflected on our consolidated balance sheets are as follows.

	As of December 31,	
	2010	2009
	(In Thousands)	
Regulatory Assets:		
Deferred employee benefit costs	$431,016	$369,877
Amounts due from customers for future income taxes, net	172,181	183,667
Depreciation	79,770	82,541
Debt reacquisition costs	73,099	79,342
Storm costs	34,741	56,288
Asset retirement obligations	21,546	20,719
Disallowed plant costs	16,354	16,462
Energy efficiency program costs	10,980	1,101
Wolf Creek outage	9,637	19,438
Ad valorem tax	5,680	1,195
Retail energy cost adjustment	—	13,298
Other regulatory assets	6,061	11,830
Total regulatory assets	$861,065	$855,758
Regulatory Liabilities:		
Removal costs	$ 70,342	$ 68,078
Nuclear decommissioning	25,467	16,658
Retail energy cost adjustment	16,402	27,488
La Cygne dismantling costs	13,268	—
Fuel supply and electricity contracts	7,800	6,001
Treasury yield hedges	7,711	—
Other post-retirement benefits costs	6,943	3,534
Ad valorem tax	4,934	5,604
Kansas tax credits	3,565	5,351
Other regulatory liabilities	7,606	7,994
Total regulatory liabilities	$164,038	$140,708

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

- **Deferred employee benefit costs:** Includes $407.2 million for pension and other post-retirement benefit obligations and $23.8 million for actual pension expense in excess of the amount of such expense recognized in setting our prices. During 2011, we will amortize to expense approximately $36.3 million of the benefit obligations. At the time of a future rate case, we expect to amortize the excess pension expense as part of resetting base prices. We do not earn a return on this asset.

- **Amounts due from customers for future income taxes, net:** In accordance with various orders, we have reduced our prices to reflect the income tax benefits associated with certain income tax deductions, thereby passing on these benefits to customers at the time we receive them. We believe it is probable that the net future increases in income taxes payable will be recovered from customers when these temporary income tax benefits reverse in future periods. We have recorded a regulatory asset, net of the regulatory liability, for these amounts on which we do not earn a return. We also have recorded a regulatory liability for our obligation to customers for income taxes recovered in earlier periods when corporate income tax rates were higher than current income tax rates. This benefit will be returned to customers as these temporary differences reverse in future periods. The income tax-related regulatory assets and liabilities as well as unamortized investment tax credits are also temporary differences for which deferred income taxes have been provided. These items are measured by the expected cash flows to be received or settled in future prices.

- **Depreciation:** Represents the difference between regulatory depreciation expense and depreciation expense we record for financial reporting purposes. We earn a return on this asset and amortize the difference over the life of the related plant.

- **Debt reacquisition costs:** Includes costs incurred to reacquire and refinance debt. These costs are amortized over the term of the new debt. We do not earn a return on this asset.

- **Storm costs:** We accumulated and deferred for future recovery costs related to restoring our electric transmission and distribution systems from damages sustained during unusually damaging storms. We amortize these costs over periods ranging from three to five years and earn a return on a majority of this asset.

- **Asset retirement obligations:** Represents amounts associated with our AROs as discussed in Note 14, “Asset Retirement Obligations.” We recover these amounts over the life of the related plant. We do not earn a return on this asset.

- **Disallowed plant costs:** In 1985, the Kansas Corporation Commission (KCC) disallowed certain costs associated with the original construction of Wolf Creek. In 1987, the KCC authorized KGE to recover these costs in prices over the useful life of Wolf Creek. We do not earn a return on this asset.

- **Energy efficiency program costs:** We accumulate and defer for future recovery costs related to our various energy efficiency programs. We will amortize such costs over a one-year period. We do not earn a return on this asset.

- **Wolf Creek outage:** Wolf Creek incurs a refueling and maintenance outage approximately every 18 months. The expenses associated with these refueling and maintenance outages are deferred and amortized over the period between such planned outages. We do not earn a return on this asset.

- **Ad valorem tax:** Represents actual costs incurred for property taxes in excess of amounts collected in our prices. We expect to recover these amounts in our prices over a one-year period. We do not earn a return on this asset.

- **Retail energy cost adjustment:** We are allowed to adjust our retail prices to reflect changes in the cost of fuel and purchased power needed to serve our customers. This item represents the actual cost of fuel consumed in producing electricity and the cost of purchased power in excess of the amounts we have collected from customers. We expect to recover in our prices this shortfall over a one-year period. We do not earn a return on this asset.

- **Other regulatory assets:** Includes various regulatory assets that individually are small in relation to the total regulatory asset balance. Other regulatory assets have various recovery periods, most of which range from three to five years.

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

- **Removal costs:** Represents amounts collected, but not yet spent, to dispose of plant assets that do not represent legal retirement obligations. This liability will be discharged as removal costs are incurred.

- **Nuclear decommissioning:** We have a legal obligation to decommission Wolf Creek at the end of its useful life. This item represents the difference between the fair value of the assets held in a decommissioning trust and the fair value of our ARO. See Note 5, "Financial Investments and Trading Securities" and Note 14, "Asset Retirement Obligations," for information regarding our nuclear decommissioning trust (NDT) fund and our ARO.

- **Retail energy cost adjustment:** We are allowed to adjust our retail prices to reflect changes in the cost of fuel and purchased power needed to serve our customers. We bill customers based on our estimated costs. This item represents the amount we collected from customers that was in excess of our actual cost of fuel and purchased power. We will refund to customers this excess recovery over a one-year period.

- **La Cygne dismantling costs:** We are contractually obligated to retire a portion of the La Cygne Generating Station (La Cygne) unit 2. This item represents amounts collected but not yet spent to retire this unit and the obligation will be discharged as we dismantle the unit.

- **Fuel supply and electricity contracts:** We use fair value accounting for some of our fuel supply and electricity contracts. This represents the non-cash net gain position on fuel supply and electricity contracts that are recorded at fair value. Under the RECA, fuel supply contract market gains accrue to the benefit of our customers.

- **Treasury yield hedges:** Represents the effective portion of the gains on treasury yield hedge transactions entered into during 2010. This amount will be amortized to interest expense over the life of the related debt. See Note 4, "Financial and Derivative Instruments, Trading Securities, Energy Marketing and Risk Management – Derivative Instruments – Cash Flow Hedges," for additional information regarding our treasury yield hedge transactions.

- **Other post-retirement benefits costs:** Represents the amount of other post-retirement benefits expense recognized in setting our prices in excess of actual other post-retirement benefits expense. At the time of a future rate case, we expect to credit this excess to customers as part of resetting our base prices.

- **Ad valorem tax:** Represents amounts collected in our prices in excess of actual costs incurred for property taxes. We will refund to customers this excess recovery over a one-year period.

- **Kansas tax credits:** Represents Kansas tax credits on investments in utility plant. Amounts will be credited to customers subsequent to their realization over the remaining lives of the utility plant giving rise to the tax credits.

- **Other regulatory liabilities:** 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.

KCC Proceedings

On October 29, 2010, the KCC issued an order, effective November 2010, allowing us to recover in our prices $5.8 million of previously deferred amounts associated with various energy efficiency programs.

On June 11, 2010, the KCC issued a final order approving an adjustment to our prices that we made earlier in 2010. The adjustment included updated transmission costs as reflected in our transmission formula rate discussed below. The new prices were effective March 16, 2010, and are expected to increase our annual retail revenues by $6.4 million.

On May 25, 2010, the KCC issued an order allowing us to adjust our prices to include costs associated with environmental investments made in 2009. The new prices were effective June 1, 2010, and are expected to increase our annual retail revenues by $13.8 million.

On January 27, 2010, the KCC issued an order allowing us to adjust our prices to include costs associated with investments in natural gas and wind generation facilities. The new prices were effective February 2010 and are expected to increase our annual retail revenues by $17.1 million.

On September 11, 2009, the KCC issued an order, effective January 1, 2009, allowing us to establish a regulatory asset or liability to track the cumulative difference between current year pension and post-retirement benefits expense and the amount of such expense recognized in setting our prices. At the time of a future rate case, we expect to amortize such regulatory asset or liability as part of resetting base rates.

On May 29, 2009, the KCC issued an order allowing us to adjust our prices to include costs associated with environmental investments made in 2008. This change went into effect on June 1, 2009, and was expected to increase our annual retail revenues by $32.5 million.

On March 6, 2009, the KCC issued an order allowing us to adjust our prices to include updated transmission costs. This change went into effect on March 13, 2009, and was expected to increase our annual retail revenues by $31.8 million.

On January 21, 2009, the KCC issued an order expected to increase our annual retail revenues by $130.0 million to reflect investments in natural gas generation facilities, wind generation facilities and other capital projects, costs to repair damage to our electrical system, which were previously deferred as a regulatory asset, higher operating costs in general and an updated capital structure. The new prices became effective on February 3, 2009.

On September 18, 2008, the KCC issued an order allowing us to adjust our prices to include updated transmission costs. This change was expected to increase our annual retail revenues by $6.1 million.

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

FERC Proceedings

On October 15, 2010, we posted our updated transmission formula rate which includes projected 2011 transmission capital expenditures and operating costs. The updated rate was effective January 1, 2011, and is expected to increase our annual transmission revenues by $15.9 million.

Our transmission formula rate that includes projected 2010 transmission capital expenditures and operating costs became effective January 1, 2010, and was expected to increase our annual transmission revenues by $16.8 million. The transmission formula rate provides the basis for our annual request with the KCC to adjust our retail prices to include updated transmission costs as noted above.

On January 12, 2010, the Federal Energy Regulatory Commission (FERC) issued an order accepting our request to implement a cost-based formula rate for electricity sales to wholesale customers. The use of a cost-based formula rate allows us to annually adjust our prices to reflect changes in our cost of service. The cost-based formula rate was effective December 1, 2009.

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

On March 24, 2008, FERC issued an order that granted our requested incentives of an additional 100 basis points above the base allowed return on equity and a 15-year accelerated recovery for an approximately 100 mile, 345 kilovolt transmission line that will run from near Wichita, Kansas, to near Salina, Kansas. We completed construction of the line in August 2010.

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

Values of Financial and Derivative Instruments

GAAP establishes a hierarchal framework for disclosing the transparency of the inputs utilized in measuring assets and liabilities at fair value. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the classification of fair value assets and liabilities within the fair value hierarchy levels. The three levels of the hierarchy and examples are as follows:

- Level 1 – Quoted prices are available in active markets for identical assets or liabilities. The types of assets and liabilities included in level 1 are highly liquid and actively traded instruments with quoted prices, such as equities listed on public exchanges and exchange-traded futures contracts.

- Level 2 – Pricing inputs are not quoted prices in active markets, but are either directly or indirectly observable. The types of assets and liabilities included in level 2 are typically measured at net asset value, comparable to actively traded securities or contracts, such as treasury securities with pricing interpolated from recent trades of similar securities, or priced with models using highly observable inputs, such as commodity options priced using observable forward prices and volatilities.

- Level 3 – Significant inputs to pricing have little or no transparency. The types of assets and liabilities included in level 3 are those with inputs requiring significant management judgment or estimation, such as the complex and subjective models and forecasts used to determine the fair value of options, real estate investments and long-term electricity supply contracts.

We carry cash and cash equivalents, short-term borrowings and variable rate debt on our consolidated balance sheets at cost, which approximates fair value. We measure the fair value of fixed-rate debt 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 amount of accounts receivable and other current financial instruments approximates fair value.

During the second quarter of 2010, we changed our investment advisor for the NDT. The transition resulted in the sale of all of our then existing level 1 and level 2 investments and the purchase of other level 2 investments. Level 2 investments, whether in the NDT or our trading securities portfolio, are held in investment funds that are measured using daily net asset values as reported by the fund managers.

We maintain certain level 3 investments in private equity, high-yield bonds and real estate securities that require significant unobservable market information to measure the fair value of the investments. The fair value of private equity investments is measured by utilizing both market- and income-based models, public company comparables, at cost or at the value derived from subsequent financings. Adjustments are made when actual performance differs from expected performance; when market, economic or company-specific conditions change; and when other news or events have a material impact on the security. Level 3 debt investments are principally invested in mortgage-backed securities and collateralized loans. Fair value for these investments is determined by using subjective market- and income-based estimates such as projected cash flows and future interest rates. To measure the fair value of real estate securities we use a combination of market- and income-based models utilizing market discount rates, projected cash flows and the estimated value into perpetuity.

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

We measure fair value based on information available as of the measurement date. The following table provides the carrying values and measured fair values of our financial instruments as of December 31, 2010 and 2009.

	Carrying Value		Fair Value	
	As of December 31,			
	2010	2009	2010	2009
	(In Thousands)			
Fixed-rate debt (a)	$2,373,373	$2,373,723	$2,570,648	$2,528,456
Fixed-rate debt of VIEs	308,317	—	341,328	—

(a) This amount does not include an equipment financing loan of $0.1 million and $1.4 million in 2010 and 2009, respectively.

Recurring Fair Value Measurements

The following table provides the amounts and the corresponding level of hierarchy for our assets and liabilities that are measured at fair value.

As of December 31, 2010	Level 1	Level 2	Level 3	Total
		(In Thousands)		
Assets:				
Energy Marketing Contracts	$ 2,432	$ 6,258	$13,787	$ 22,477
Nuclear Decommissioning Trust:				
Domestic equity	—	60,586	2,867	63,453
International equity	—	18,966	—	18,966
Core bonds	—	31,906	—	31,906
High-yield bonds	—	9,267	305	9,572
Real estate securities	—	—	3,049	3,049
Cash equivalents	44	—	—	44
Total Nuclear Decommissioning Trust	44	120,725	6,221	126,990
Trading Securities:				
Domestic equity	—	21,207	—	21,207
International equity	—	5,128	—	5,128
Core bonds	—	13,077	—	13,077
Total Trading Securities	—	39,412	—	39,412
Treasury Yield Hedge	—	7,711	—	7,711
Total Assets Measured at Fair Value	$ 2,476	$174,106	$20,008	$196,590
Liabilities:				
Energy Marketing Contracts	$ 1,888	$ 5,820	$ 1,972	$ 9,680
As of December 31, 2009				
Assets:				
Energy Marketing Contracts	$ 7,310	$ 17,071	$19,431	$ 43,812
Nuclear Decommissioning Trust:				
Domestic equity	34,961	5,317	2,262	42,540
International equity	1,208	24,736	—	25,944
Core bonds	16,082	5,524	—	21,606
High-yield bonds	5,579	—	5,741	11,320
Real estate securities	—	—	3,635	3,635
Commodities	5,563	—	—	5,563
Cash equivalents	1,660	—	—	1,660
Total Nuclear Decommissioning Trust	65,053	35,577	11,638	112,268
Trading Securities:				
Domestic equity	—	18,344	—	18,344
International equity	—	4,422	—	4,422
Core bonds	—	11,853	—	11,853
Total Trading Securities	—	34,619	—	34,619
Total Assets Measured at Fair Value	$72,363	$ 87,267	$31,069	$190,699
Liabilities:				
Energy Marketing Contracts	$ 8,964	$ 15,286	$15,121	$ 39,371

We do not offset the fair value of energy marketing contracts executed with the same counterparty. As of December 31, 2010, we had no right to reclaim cash collateral and $0.7 million for our obligation to return cash collateral. As of December 31, 2009, we had recorded $0.3 million for our right to reclaim cash collateral and $1.8 million for our obligation to return cash collateral.

The following table provides reconciliations of assets and liabilities measured at fair value using significant level 3 inputs for the years ended December 31, 2010 and 2009.

	Energy Marketing Contracts, net	Nuclear Decommissioning Trust: Domestic Equity	Nuclear Decommissioning Trust: High-yield Bonds	Nuclear Decommissioning Trust: Real Estate Securities	Net Balance
			(In Thousands)		
Balance as of December 31, 2009	$ 4,310	$ 2,262	$ 5,741	$ 3,635	$ 15,948
Total realized and unrealized gains (losses) included in:					
Earnings (a)	(2,585)	—	—	—	(2,585)
Regulatory assets	3,311(b)	—	—	—	3,311
Regulatory liabilities	8,148(b)	16	367	(586)	7,945
Purchases, issuances and settlements	(1,369)	589	(5,803)	—	(6,583)
Balance as of December 31, 2010	$ 11,815	$ 2,867	$ 305	$ 3,049	$ 18,036
Balance as of December 31, 2008	$ 44,541	$ 2,006	$ —	$ 6,028	$ 52,575
Total realized and unrealized gains (losses) included in:					
Earnings (a)	3,060	—	—	—	3,060
Regulatory assets	(15,382) (b)	—	—	—	(15,382)
Regulatory liabilities	(22,750) (b)	(39)	1,134	(2,393)	(24,048)
Purchases, issuances and settlements	(5,159)	295	4,607(c)	—	(257)
Balance as of December 31, 2009	$ 4,310	$ 2,262	$ 5,741	$ 3,635	$ 15,948

(a) Unrealized and realized gains and losses included in earnings resulting from energy marketing activities are reported in revenues.
(b) Includes changes in the fair value of certain fuel supply and electricity contracts.
(c) We used proceeds from the sale of certain debt investments measured at fair value using level 2 inputs to purchase different debt investments that require significant unobservable inputs in order to measure their fair value.

A portion of the gains and losses contributing to changes in net assets in the above table is unrealized. The following table summarizes the unrealized gains and losses we recorded on our consolidated financial statements during the years ended December 31, 2010 and 2009, attributed to level 3 assets and liabilities.

	Year Ended December 31, 2010				
		Nuclear Decommissioning Trust			
	Energy Marketing Contracts, net	Domestic Equity	High-yield Bonds	Real Estate Securities	Net Balance
	(In Thousands)				
Total unrealized gains (losses) included in:					
Earnings (a)	$ (1,441)	$ —	$ —	$ —	$ (1,441)
Regulatory assets	180(b)	—	—	—	180
Regulatory liabilities	2,633(b)	23	(31)	(586)	2,039
Total	$ 1,372	$ 23	$ (31)	$ (586)	$ 778
	Year Ended December 31, 2009				
Total unrealized gains (losses) included in:					
Earnings (a)	$ (474)	$ —	$ —	$ —	$ (474)
Regulatory assets	(8,545) (b)	—	—	—	(8,545)
Regulatory liabilities	(9,634) (b)	(39)	1,134	(2,497)	(11,036)
Total	$ (18,653)	$ (39)	$ 1,134	$ (2,497)	$ (20,055)

(a) Unrealized gains and losses included in earnings resulting from energy marketing activities are reported in revenues.
(b) Includes changes in the fair value of certain fuel supply and electricity contracts.

Some of our investments in the NDT and all of our trading securities do not have readily determinable fair values and are either with investment companies or companies that follow accounting guidance consistent with investment companies. In certain situations these investments may have redemption restrictions. The following table provides further information on these investments.

	As of December 31, 2010		As of December 31, 2009		As of December 31, 2010	
	Fair Value	Unfunded Commitments	Fair Value	Unfunded Commitments	Redemption Frequency	Length of Settlement
	(In thousands)					
Nuclear Decommissioning Trust:						
Domestic equity	$ 2,867	$ 2,523	$ 7,579	$ 3,111	(a)	(a)
High-yield bonds	305	—	5,741	—	(b)	(b)
Real estate securities	3,049	—	3,635	—	(c)	(c)
Total	$ 6,221	$ 2,523	$ 16,955	$ 3,111		
Trading Securities:						
Domestic equity	$ 21,207	$ —	$ 18,344	$ —	Upon Notice	1 day
International equity	5,128	—	4,422	—	Upon Notice	1 day
Core bonds	13,077	—	11,853	—	Upon Notice	1 day
Total Trading Securities	39,412	—	34,619	—		
Total	$ 45,633	$ 2,523	$ 51,574	$ 3,111		

(a) This investment is in two long-term private equity funds that do not permit early withdrawal. Our investments in these funds cannot be distributed until the underlying investments have been liquidated which may take years from the date of initial liquidation. One fund has begun to make distributions and we expect the other to begin in 2013.

(b) We expect to completely settle this fund in the second quarter of 2011.

(c) The nature of this investment requires relatively long holding periods which do not necessarily accommodate ready liquidity. In addition, adverse financial conditions affecting residential and commercial real estate markets have further limited any liquidity associated with this investment.

Nonrecurring Fair Value Measurements

We have recognized legal obligations associated with the disposal of long-lived assets that result from the acquisition, construction, development or normal operations of such assets. In 2010 we did not incur any additional AROs. In 2009 we incurred $21.6 million of additional AROs, including $20.3 million increase in our ARO to reflect revisions to the estimated cost to decommission Wolf Creek. We initially record AROs at fair value for the estimated cost to satisfy the retirement obligation. The fair value is measured by estimating the cost to satisfy the retirement obligation then discounting that value at a risk- and inflation-adjusted rate. To determine the cost to satisfy the retirement obligation, we must estimate the cost of basic inputs such as labor, energy, materials and disposal. To determine the appropriate discount rate, we use inputs such as inflation rates, short and long-term yields for U.S. government securities and our nonperformance risk. Due to the significant unobservable inputs required in our measurement, we have determined that our fair value measurements of our AROs are level 3 in the fair value hierarchy. For additional information on our AROs, see Note 14, “Asset Retirement Obligations.”

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Derivative Instruments

Cash Flow Hedges

In 2010, we entered into treasury yield hedge transactions for a total notional amount of $100.0 million in order to manage our interest rate risk associated with a future anticipated issuance of fixed-rate debt, which must occur within 18 months of the initial treasury yield hedge transaction date. Such transactions are designated and qualify as cash flow hedges and are measured at fair value by estimating the net present value of a series of payments using market-based models with observable inputs, such as the spread between the 30-year U.S. Treasury bill yield and the contracted, fixed yield. As a result of regulatory accounting treatment, we report the effective portion of the gain or loss on these derivative instruments as a regulatory liability or regulatory asset and will amortize such amounts to interest expense over the life of the related debt. We record hedge ineffectiveness gains in other income and hedge ineffectiveness losses in other expense on our consolidated statements of income. As of December 31, 2010, the fair value of the treasury yield hedge transactions was $7.7 million, which we recorded in other assets on our consolidated balance sheet. We also recorded this same amount in long-term regulatory liabilities on our consolidated balance sheet to reflect the effective portion of the gains on these transactions for the year ended December 31, 2010.

Commodity Contracts

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

We classify these commodity derivative instruments 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. With the exception of certain fuel supply and electricity contracts, which we record as regulatory assets or regulatory liabilities, we include the change in the fair value of energy marketing contracts in revenues on our consolidated statements of income.

The following table presents the fair value of commodity derivative instruments reflected on our consolidated balance sheets.

Commodity Derivatives Not Designated as Hedging Instruments as of December 31, 2010

Asset Derivatives		Liability Derivatives	
Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
	(In thousands)		(In thousands)
Current assets:		Current liabilities:	
Energy marketing contracts	$ 13,005	Energy marketing contracts	$ 9,670
Other assets:		Long-term liabilities:	
Energy marketing contracts	9,472	Energy marketing contracts	10
Total	$ 22,477	Total	$ 9,680

Commodity Derivatives Not Designated as Hedging Instruments as of December 31, 2009

Asset Derivatives		Liability Derivatives	
Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
	(In thousands)		(In thousands)
Current assets:		Current liabilities:	
Energy marketing contracts	$ 33,159	Energy marketing contracts	$ 39,161
Other assets:		Long-term liabilities:	
Energy marketing contracts	10,653	Energy marketing contracts	210
Total	$ 43,812	Total	$ 39,371

The following table presents how changes in the fair value of commodity derivative instruments affected our consolidated financial statements for the years ended December 31, 2010 and 2009.

	Year Ended December 31, 2010	Year Ended December 31, 2009	
Location	Net Gain Recognized	Net Gain Recognized	Net Loss Recognized
	(In Thousands)		
Revenues increase	$ 712	$ 7,790	$ —
Regulatory assets (decrease) increase	(7,604)	—	7,064
Regulatory liabilities increase (decrease)	1,799	—	(30,330)

As of December 31, 2010 and 2009, we had under contract the following energy-related products.

		Net Quantity as of	
	Unit of Measure	December 31, 2010	December 31, 2009
Electricity	MWh	2,791,966	4,147,800
Natural Gas	MMBtu	1,150,000	648,000
Coal	Ton	—	3,500,000

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 net open positions, we are exposed to the risk that changing market prices could have a material adverse impact on our consolidated financial results.

Energy Marketing Activities

Within our energy trading portfolio, we may establish certain positions intended to economically hedge a portion of physical sale or purchase contracts and we may enter into certain positions attempting to take advantage of market trends and conditions. We use the term economic hedge to mean a strategy intended to manage risks of volatility in prices or rate movements on selected assets, liabilities or anticipated transactions by creating a relationship in which gains or losses on derivative instruments are expected to offset the losses or gains on the assets, liabilities or anticipated transactions exposed to such market risks.

Price Risk

We use various types of fuel, including coal, natural gas, uranium, diesel and oil, to operate our plants and purchase power to meet customer demand. We are exposed to market risks from commodity price changes for electricity and other energy-related products and interest rates that could affect our consolidated financial results, including cash flows. We manage our exposure to these market risks through our regular operating and financing activities and, when we deem appropriate, we economically hedge a portion of these risks through the use of derivative financial instruments for non-trading purposes.

Factors that affect our commodity price exposure are the quantity and availability of fuel used for generation, the availability of our generating plants and the quantity of electricity customers consume. Quantities of fossil fuel we use to generate electricity fluctuate from period to period based on availability, price and deliverability of a given fuel type, as well as planned and unscheduled outages at our generating plants that use fossil fuels. Our commodity exposure is also affected by our nuclear plant refueling and maintenance schedule. Our customers' electricity usage also varies based on weather, the economy and numerous other factors.

The wholesale power and fuel markets are volatile. This volatility impacts our costs of purchased power, fuel costs for our generating plants and our participation in energy markets. We trade various types of fuel primarily to reduce exposure related to the volatility of commodity prices. A significant portion of our coal requirements is purchased under long-term contracts to hedge much of the fuel exposure for customers. 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.

Interest Rate Risk

We have entered into numerous fixed and variable rate debt obligations. For details, see Note 9, "Long-Term Debt." We manage our interest rate risk related to these debt obligations by limiting our variable interest rate exposure, utilizing various maturity dates and entering into treasury yield hedge transactions. We may also use other financial derivative instruments, such as interest rate swaps.

Credit Risk

In addition to commodity price risk, we are exposed to credit risks associated with the financial condition of counterparties, product location (basis) pricing differentials, physical liquidity constraint 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 intended to reduce our overall credit risk exposure to a level we deem acceptable and include the right to offset derivative assets and liabilities by counterparty.

We have derivative instruments with commodity exchanges and other counterparties that do not contain objective credit-risk-related contingent features. However, certain of our derivative instruments contain collateral provisions subject to credit agency ratings of our senior unsecured debt. If our senior unsecured debt ratings were to decrease or fall below investment grade, the counterparties to the derivative instruments, pursuant to the provisions, could require collateralization on derivative instruments. The aggregate fair value of all derivative instruments with objective credit-risk-related contingent features that were in a liability position as of December 31, 2010 and 2009, was $1.6 million and $1.4 million, respectively, for which we had posted no collateral. If all credit-risk-related contingent features underlying these agreements had been triggered as of December 31, 2010 and 2009, we would have been required to provide to our counterparties $1.6 million and $0.1 million, respectively, of additional collateral after taking into consideration the offsetting impact of derivative assets and net accounts receivable.

5. FINANCIAL INVESTMENTS AND TRADING SECURITIES

We report some of our investments in debt and equity securities at fair value. We classify these investments as either trading securities or available-for-sale securities as described below.

Trading Securities

We have equity and debt investments in a trust used to fund retirement benefits that we classify as trading securities. We include unrealized gains or losses on these securities in investment earnings on our consolidated statements of income. For the years ended December 31, 2010 and 2009, we recorded unrealized gains on these securities of $4.3 million and $11.3 million, respectively. We recorded an unrealized loss on these securities of $9.5 million for the year ended December 31, 2008.

Available-for-Sale Securities

We hold investments in equity and debt securities in a trust fund for the purpose of funding the decommissioning of Wolf Creek. We have classified these investments as available-for-sale and have recorded all such investments at their fair market value as of December 31, 2010 and 2009. At December 31, 2010, investments in the NDT fund were allocated 50% to domestic equity, 15% to international equity, 25% to core bonds, 8% to high-yield bonds, 2% to real estate securities and less than 1% to cash and cash equivalents. The core bond fund is limited to ensure that at least 80% of funds are invested in investment grade U.S. corporate and government fixed income securities, including mortgage-backed securities. As of December 31, 2010, the fair value of the debt securities in the NDT fund was $41.5 million, held entirely in bond funds.

Using the specific identification method to determine cost, we realized a $13.2 million gain in 2010 and losses of $7.8 million and $20.1 million in 2009 and 2008, respectively, on our available-for-sale securities. We record net realized and unrealized gains and losses in regulatory liabilities on our consolidated balance sheets. This reporting is consistent with the method we use to account for the decommissioning costs we recover in our prices. Gains or losses on assets in the trust fund are recorded as increases or decreases to regulatory liabilities and could result in lower or higher funding requirements for decommissioning costs, which we believe would be reflected in the prices paid by our customers.

The following table presents the costs and fair values of investments in the NDT fund as of December 31, 2010 and 2009.

		Gross Unrealized		
Security Type	Cost	Gain	Loss	Fair Value
		(In Thousands)		
2010:				
Domestic equity	$ 58,592	$ 4,972	$ (111)	$ 63,453
International equity	17,249	1,717	—	18,966
Core bonds	32,054	—	(148)	31,906
High-yield bonds	9,086	486	—	9,572
Real estate securities	6,207	—	(3,158)	3,049
Cash equivalents	44	—	—	44
Total	$123,232	$ 7,175	$(3,417)	$ 126,990
2009:				
Domestic equity	$ 37,648	$ 7,180	$(2,288)	$ 42,540
International equity	22,014	4,835	(905)	25,944
Core bonds	20,260	1,346	—	21,606
High-yield bonds	11,749	31	(460)	11,320
Real estate securities	6,206	—	(2,571)	3,635
Commodities	5,895	—	(332)	5,563
Cash equivalents	1,660	—	—	1,660
Total	$105,432	$13,392	$(6,556)	$ 112,268

The following table presents the fair value and the gross unrealized losses of the available-for-sale securities held in the NDT fund aggregated by investment category and the length of time that individual securities have been in a continuous unrealized loss position as of December 31, 2010 and 2009.

	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)					
2010:						
Domestic equity	$ 2,867	$ (111)	$ —	$ —	$ 2,867	$ (111)
Core bonds	31,906	(148)	—	—	31,906	(148)
Real estate securities	—	—	3,049	(3,158)	3,049	(3,158)
Total	$ 34,773	$ (259)	$ 3,049	$ (3,158)	$ 37,822	$ (3,417)
2009:						
Domestic equity	$ 4,123	$ (361)	$ 10,061	$ (1,927)	$ 14,184	$ (2,288)
International equity	198	(20)	6,253	(885)	6,451	(905)
High-yield bonds	—	—	5,579	(460)	5,579	(460)
Real estate securities	40	(16)	3,595	(2,555)	3,635	(2,571)
Commodities	—	—	5,563	(332)	5,563	(332)
Total	$ 4,361	$ (397)	$ 31,051	$ (6,159)	$ 35,412	$ (6,556)

6. PROPERTY, PLANT AND EQUIPMENT

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

	As of December 31,	
	2010	2009
	(In Thousands)	
Electric plant in service	$ 8,254,884	$ 8,057,793
Electric plant acquisition adjustment	802,318	802,318
Accumulated depreciation	(3,563,566)	(3,370,805)
	5,493,636	5,489,306
Construction work in progress	392,701	214,705
Nuclear fuel, net	78,102	67,729
Net property, plant and equipment	$ 5,964,439	$ 5,771,740

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

	As of December 31,	
	2010	2009
	(In Thousands)	
Electric plant of VIEs	$ 543,593	$ —
Accumulated depreciation of VIEs	(198,556)	—
Net property, plant and equipment of VIEs	$ 345,037	$ —

We recorded depreciation expense on property, plant and equipment of $249.2 million in 2010, $228.6 million in 2009 and $180.8 million in 2008. Approximately $9.7 million of depreciation expense in 2010 was attributable to property, plant and equipment of VIEs.

7. JOINT OWNERSHIP OF UTILITY PLANTS

Under joint ownership agreements with other utilities, we have undivided ownership interests in four electric generating stations. Energy generated and operating expenses are divided on the same basis as ownership with each owner reflecting its respective costs in its statements of income and each owner responsible for its own financing. Information relative to our ownership interest in these facilities as of December 31, 2010, is shown in the table below.

		Our Ownership as of December 31, 2010					
		In-Service Dates	Investment	Accumulated Depreciation	Construction Work in Progress	Net MW	Ownership Percentage
				(Dollars in Thousands)			
La Cygne unit 1	(a)	June 1973	$ 284,101	$ (145,356)	$ 48,072	368	50
JEC unit 1	(a)	July 1978	482,582	(195,849)	8,939	666	92
JEC unit 2	(a)	May 1980	443,128	(187,356)	48,513	667	92
JEC unit 3	(a)	May 1983	673,567	(251,673)	883	659	92
Wolf Creek	(b)	Sept. 1985	1,469,700	(733,036)	71,299	544	47
State Line	(c)	June 2001	111,979	(41,423)	129	201	40
Total			$3,465,057	$ (1,554,693)	$ 177,835	3,105	

(a) Jointly owned with Kansas City Power & Light Company (KCPL). Amounts include the consolidated VIE containing an 8% leasehold interest in JEC.
(b) Jointly owned with KCPL and Kansas Electric Power Cooperative, Inc.
(c) Jointly owned with Empire District Electric Company.

We include in operating expenses on our consolidated statements of income our share of operating expenses of the above plants. Our share of other transactions associated with the plants is included in the appropriate classification on our consolidated financial statements.

In addition, we also consolidate a VIE that holds our 50% leasehold interest in La Cygne unit 2, which represents 341 megawatts (MW) of net capacity. The VIE's initial investment in the 50% interest was $392.1 million and accumulated depreciation was $166.0 million as of December 31, 2010. We include these amounts in property, plant and equipment of variable interest entities, net on our consolidated balance sheets. See Note 17, "Variable Interest Entities," for additional information about VIEs.

8. SHORT-TERM DEBT

Westar Energy has a $730.0 million revolving credit facility with a syndicate of banks that terminates on March 17, 2012. On January 27, 2010, FERC approved our request for authority to issue short-term securities in an aggregate amount up to $1.0 billion including, without limitation, by increasing the size of Westar Energy's revolving credit facility. As of December 31, 2010, we had not yet exercised the increase in our authority. In addition, as of December 31, 2010, $226.7 million had been borrowed and an additional $21.5 million of letters of credit had been issued under the revolving credit facility.

The weighted average interest rate on our borrowings under the revolving credit facility was 0.61% and 0.58% as of December 31, 2010, and December 31, 2009, respectively.

Additional information regarding our short-term debt is as follows.

	As of December 31,	
	2010	2009
	(Dollars in Thousands)	
Weighted average short-term debt outstanding during the year	$213,041	$ 200,547
Weighted daily average interest rates during the year, excluding fees	0.63%	0.76%

Our interest expense on short-term debt was $1.9 million in 2010, $2.2 million in 2009 and $9.7 million in 2008.

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9. LONG-TERM DEBT

Outstanding Debt

The following table summarizes our long-term debt outstanding.

	As of December 31, 2010	As of December 31, 2009
	(In Thousands)	
Westar Energy		
First mortgage bond series:		
6.00% due 2014	$ 250,000	$ 250,000
5.15% due 2017	125,000	125,000
5.95% due 2035	125,000	125,000
5.10% due 2020	250,000	250,000
5.875% due 2036	150,000	150,000
6.10% due 2047	150,000	150,000
8.625% due 2018	300,000	300,000
	1,350,000	1,350,000
Pollution control bond series:		
Variable due 2032, 0.60% as of December 31, 2010; 0.48% as of December 31, 2009	45,000	45,000
Variable due 2032, 0.54% as of December 31, 2010; 0.54% as of December 31, 2009	30,500	30,500
5.00% due 2033	57,530	57,760
	133,030	133,260
Other long-term debt:		
4.36% equipment financing loan due 2011	61	1,406
KGE		
First mortgage bond series:		
6.53% due 2037	175,000	175,000
6.15% due 2023	50,000	50,000
6.64% due 2038	100,000	100,000
6.70% due 2019	300,000	300,000
	625,000	625,000
Pollution control bond series:		
5.10% due 2023	13,343	13,463
Variable due 2027, 0.54% as of December 31, 2010; 0.64% as of December 31, 2009	21,940	21,940
5.30% due 2031	108,600	108,600
5.30% due 2031	18,900	18,900
Variable due 2032, 0.54% as of December 31, 2010; 0.64% as of December 31, 2009	14,500	14,500
Variable due 2032, 0.54% as of December 31, 2010; 0.64% as of December 31, 2009	10,000	10,000
4.85% due 2031	50,000	50,000
5.60% due 2031	50,000	50,000
6.00% due 2031	50,000	50,000
5.00% due 2031	50,000	50,000
	387,283	387,403
Total long-term debt	2,495,374	2,497,069
Unamortized debt discount (a)	(4,442)	(4,990)
Long-term debt due within one year	(61)	(1,345)
Long-term debt, net	$2,490,871	$2,490,734
Variable Interest Entities		
7.77% due 2013 (b)	$ 5,095	$ —
6.99% due 2014 (b)	3,237	—
5.92 % due 2019 (b)	31,171	—
5.647% due 2021 (b)	266,393	—
Total long-term debt of variable interest entities	305,896	—
Unamortized debt premium (a)	2,421	—
Long-term debt of variable interest entities due within one year	(30,155)	—
Long-term debt of variable interest entities, net	$ 278,162	$ —

(a) We amortize debt discounts and premiums to interest expense over the term of the respective issues.
(b) Portions of our payments related to this debt reduce the principal balances each year until maturity.

The Westar Energy and KGE mortgages 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 first mortgage bonds authorized by its Mortgage and Deed of Trust, dated July 1, 1939, as supplemented, is subject to certain limitations as described below. The amount of KGE first mortgage bonds authorized by the KGE Mortgage and Deed of Trust, dated April 1, 1940, as supplemented and amended in June 2009, is limited to a maximum of $3.5 billion, unless amended further. 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, 2010, based on an assumed interest rate of 5.90%, approximately $817.0 million principal amount of additional first mortgage bonds could be issued under the most restrictive provisions in Westar Energy's mortgage, except in connection with certain refundings. As of December 31, 2010, approximately $635.0 million principal amount of additional KGE first mortgage bonds could be issued under the most restrictive provisions in KGE's mortgage.

As of December 31, 2010, we had $121.9 million of variable rate, tax-exempt bonds. Interest rates payable under these bonds are normally set by auctions, which occur every 35 days. However, auctions for these bonds have failed over the past few years, resulting in volatile alternative index-based interest rates for these bonds. With the KCC's approval, on October 15, 2009, KGE refinanced $50.0 million of auction rate bonds at a fixed interest rate of 5.00% and a maturity date of June 1, 2031. We continue to monitor the credit markets and evaluate our options with respect to our remaining auction rate bonds.

On August 3, 2009, Westar Energy repaid $145.1 million principal amount of 7.125% unsecured senior notes with borrowings under Westar Energy's revolving credit facility.

On June 11, 2009, KGE issued $300.0 million principal amount of first mortgage bonds at a discount yielding 6.725%, bearing stated interest at 6.70% and maturing on June 15, 2019. KGE received net proceeds of $297.5 million.

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

Debt Covenants

Some of our debt instruments contain restrictions that require us to maintain leverage ratios as defined in the agreements. We calculate these ratios in accordance with our credit agreements. We use these ratios solely to determine compliance with our various debt covenants. We were in compliance with these covenants as of December 31, 2010.

Maturities

The principal amounts of our long-term debt maturities as of December 31, 2010, are as follows.

Year	Long-term debt	Long-term debt of VIEs
	(In Thousands)	
2011	$ 61	$ 30,155
2012	—	28,118
2013	—	25,941
2014	250,000	27,479
Thereafter	2,245,313	194,203
Total maturities	$ 2,495,374	$ 305,896

Interest expense on long-term debt was $144.1 million in 2010, $139.6 million in 2009 and $95.7 million in 2008. Interest expense on long-term debt of VIEs was $18.7 million in 2010.

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10. TAXES

Income tax expense is composed of the following components.

	Year Ended December 31,		
	2010	2009	2008
	(In Thousands)		
Income Tax Expense (Benefit) from Continuing Operations:			
Current income taxes:			
Federal	$ (32,107)	$ 2,428	$ (16,484)
State	(3,030)	9,975	(14,841)
Deferred income taxes:			
Federal	102,568	46,148	35,818
State	20,305	3,003	2,147
Investment tax credit amortization	(2,704)	(2,704)	(2,704)
Income tax expense from continuing operations	$ 85,032	$ 58,850	$ 3,936
Income Tax Expense (Benefit) from Discontinued Operations:			
Current income taxes:			
Federal	$ —	$ (25,528)	$ —
State	—	(10,418)	—
Deferred income taxes:			
Federal	—	(20,549)	—
Income tax expense from discontinued operations	$ —	$ (56,495)	$ —
Total income tax expense	$ 85,032	$ 2,355	$ 3,936

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

	As of December 31,	
	2010	2009
	(In Thousands)	
Current deferred tax assets	$ 30,248	$ 7,927
Non-current deferred tax liabilities	1,102,625	964,461
Net deferred tax liabilities	$1,072,377	$956,534

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.

	As of December 31,	
	2010	2009
	(In Thousands)	
Deferred tax assets:		
Deferred employee benefit costs	$ 155,400	$ 132,770
Business tax credit carryforwards (a)	134,629	101,347
Deferred gain on sale-leaseback	45,381	47,800
Deferred compensation	40,401	38,198
Accrued liabilities	35,714	35,230
Alternative minimum tax carryforward (b)	34,270	18,406
Deferred state income taxes	14,215	26,093
Disallowed costs	13,357	14,000
Long-term energy contracts	3,720	5,874
Capital loss carryforward (c)	3,527	6,075
Other	29,857	15,161
Total gross deferred tax assets	510,471	440,954
Less: Valuation allowance (c)	59,415	9,710
Deferred tax assets	$ 451,056	$ 431,244
Deferred tax liabilities:		
Accelerated depreciation	$ 931,898	$ 789,850
Acquisition premium	195,947	203,959
Deferred employee benefit costs	161,035	141,974
Amounts due from customers for future income taxes, net	152,877	165,975
Debt reacquisition costs	23,864	26,046
Deferred state income taxes	16,577	24,882
Storm costs	13,733	22,160
Other	27,502	12,932
Total deferred tax liabilities	$1,523,433	$1,387,778
Net deferred tax liabilities	$1,072,377	$ 956,534

(a) As of December 31, 2010, we had available federal general business tax credits of $18.4 million and state investment tax credits of $116.2 million. The federal general business tax credits were primarily generated from affordable housing partnerships in which we sold the majority of our interests in 2001. These tax credits expire beginning in 2019 and ending in 2025. We believe these tax credits will be fully utilized prior to expiration. The state investment tax credits expire beginning in 2013 and ending in 2019. As we do not expect to realize sufficient state taxable income in the future, a valuation allowance of $51.9 million has been established against the unused credits which have been deferred pursuant to regulatory treatment.

(b) As of December 31, 2010, we had available alternative minimum tax credit carryforwards of $34.3 million. These tax credits have an unlimited carryforward period.

(c) As of December 31, 2010, we had a net capital loss of $8.9 million that is available to offset future capital gains. The net capital loss will expire in 2014. As we do not expect to realize any significant capital gains in the future, a valuation allowance of $3.5 million has been established. In addition, a valuation allowance of $4.0 million has been established for certain deferred tax assets related to the write-down of other investments. We also established a valuation allowance of $51.9 million as described in (a) above. The total valuation allowance related to the deferred tax assets was $59.4 million as of December 31, 2010, and $9.7 million as of December 31, 2009.

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

Our 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 income tax rates and the federal statutory income tax rates are as follows.

	For the Year Ended December 31,		
	2010	2009	2008
Statutory federal income tax rate from continuing operations	35.0%	35.0%	35.0%
Effect of:			
Corporate-owned life insurance policies	(6.1)	(8.2)	(9.1)
State income taxes	3.8	4.3	(4.5)
Production tax credits	(3.4)	(3.0)	—
Accelerated depreciation flow through and amortization	2.6	3.7	2.3
Amortization of federal investment tax credits	(0.9)	(1.4)	(1.5)
Capital loss utilization	(0.7)	(0.4)	—
AFUDC equity	(0.4)	(0.9)	(3.5)
Liability for unrecognized income tax benefits	(0.2)	0.2	(15.4)
Other	(0.7)	0.1	(1.1)
Effective income tax rate from continuing operations	29.0%	29.4%	2.2%

We file income tax returns in the U.S. federal jurisdiction, and various state and foreign jurisdictions. The income tax returns we file will likely be audited by the Internal Revenue Service (IRS) or other tax 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 remains open for tax year 2007 and forward with tax year 2009 currently under examination by the IRS.

In November 2010, the IRS commenced an examination of our federal income tax return for tax year 2009. Also in 2010, the IRS commenced and substantially concluded its examination of the federal income tax return we filed for tax year 2008 without significant changes.

In November 2009, the IRS completed its examination of the federal income tax return and the amended federal income tax returns we filed for tax years 1999, 2005, 2006 and 2007. The examination resulted in a tax refund of $34.9 million. The examination results were approved by the Joint Committee on Taxation of the U.S. Congress and accepted by the IRS in April 2010.

In January 2009, we reached a settlement with the IRS for tax years 2003 and 2004 that included a determination of the amount of the net capital loss and net operating loss carryforwards available from the sale of a former subsidiary in 2004. This settlement resulted in our recording in 2009 a net earnings benefit from discontinued operations of approximately $33.7 million, net of $22.8 million paid to the former subsidiary under the sale agreement.

In February 2008, we reached a settlement with the IRS for tax years 1995 through 2002 on issues related principally to the method used to capitalize overheads to electric plant. This settlement resulted in a 2008 net earnings benefit of approximately $39.4 million, including interest, due to the recognition of previously unrecognized income tax benefits.

The amount of unrecognized income tax benefits decreased from $8.4 million at December 31, 2009, to $1.9 million at December 31, 2010. The net decrease in unrecognized income tax benefits for which a liability was not recorded was largely attributable to the reversal of $8.2 million of tax positions due to the completion of the IRS audits and the expiration of the statute of limitation. We do not expect significant changes in the liability for unrecognized income tax benefits in the next 12 months. A reconciliation of the beginning and ending amount of unrecognized income tax benefits is as follows:

	2010	2009	2008
		(In Thousands)	
Liability for unrecognized income tax benefits at January 1	$ 8,357	$ 38,980	$ 70,833
Additions based on tax positions related to the current year	608	2,254	4,576
Additions for tax positions of prior years	2,323	—	—
Reductions for tax positions of prior years	(1,241)	(25,722)	(3,639)
Settlements	(8,159)	(7,155)	(32,790)
Liability for unrecognized income tax benefits at December 31	1,888	8,357	38,980
Unrecognized income tax benefits related to amended returns filed in 2007	—	—	53,092
Unrecognized income tax benefits at December 31	$ 1,888	$ 8,357	$ 92,072

The amounts of unrecognized income tax benefits that, if recognized, would favorably impact our effective income tax rate, were $1.3 million, $2.1 million and $54.8 million (net of tax) as of December 31, 2010, 2009 and 2008, respectively. Included in the liability for unrecognized income tax benefits balances was $1.3 million, $2.1 million and $1.7 million (net of tax) of tax positions, which if recognized, would favorably impact our effective income tax rates as of December 31, 2010, 2009 and 2008, respectively.

Interest related to income tax uncertainties is classified as interest expense and accrued interest liability. During 2010, 2009 and 2008, we reversed interest expense previously recorded for income tax uncertainties of $1.0 million, $2.4 million and $15.9 million, respectively. As of December 31, 2010 and 2009, we had $0.4 million and $1.4 million, respectively, accrued for interest on our liability related to unrecognized income tax benefits. We accrued no tax related penalties at either December 31, 2010, or December 31, 2009.

As of December 31, 2010 and 2009, we had recorded $3.6 million for probable assessments of taxes other than income taxes.

11. EMPLOYEE BENEFIT PLANS

Pension and Other Post-Retirement Benefit Plans

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 an employee’s compensation during the 60 highest paid consecutive months out of 120 before retirement. Non-union employees hired after December 31, 2001, are covered by the same defined benefit pension plan; however, their benefits are derived from a cash balance account formula. We also maintain a non-qualified Executive Salary Continuation Plan for the benefit of certain current and retired executive officers. With the exception of one current executive officer, we have discontinued accruing any future benefits under this non-qualified plan.

In accordance with a 2009 KCC order, we expect to fund our pension plan each year at least to a level equal to our current year pension expense. We must also meet minimum funding requirements under the Employee Retirement Income Security Act (ERISA), as amended by the Pension Protection Act. We may contribute additional amounts from time to time as deemed appropriate.

In addition to providing pension benefits, we provide certain post-retirement health care and life insurance benefits for substantially all retired employees. We accrue and recover in our prices the costs of post-retirement benefits during an employee's years of service. We fund the portion of net periodic costs for other post-retirement benefits included in our prices.

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 other post-retirement benefit plans. See Note 12, "Wolf Creek Employee Benefit Plans," for information about Wolf Creek's benefit plans.

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

	Pension Benefits		Post-retirement Benefits	
As of December 31,	2010	2009	2010	2009
	(In Thousands)			
Change in Benefit Obligation:				
Benefit obligation, beginning of year	$ 662,495	$ 629,238	$ 128,998	$ 133,881
Service cost	13,926	12,882	1,526	1,529
Interest cost	39,391	38,162	7,083	6,917
Plan participants' contributions	—	—	3,292	3,098
Benefits paid	(29,690)	(28,526)	(11,090)	(9,960)
Actuarial losses (gains)	60,662	10,692	7,950	(13,063)
Amendments	676	47	—	6,596
Benefit obligation, end of year	$ 747,460	$ 662,495	$ 137,759	$ 128,998
Change in Plan Assets:				
Fair value of plan assets, beginning of year	$ 404,243	$ 310,531	$ 74,114	$ 52,804
Actual return on plan assets	33,359	83,128	9,849	17,898
Employer contributions	22,400	37,304	10,512	9,951
Plan participants' contributions	—	—	3,147	2,953
Part D Reimbursements	—	—	317	589
Benefits paid	(27,769)	(26,720)	(10,955)	(10,081)
Fair value of plan assets, end of year	$ 432,233	$ 404,243	$ 86,984	$ 74,114
Funded status, end of year	$(315,227)	$(258,252)	$ (50,775)	$ (54,884)
Amounts Recognized in the Balance Sheets Consist of:				
Current liability	$ (2,030)	$ (1,984)	$ (91)	$ (121)
Noncurrent liability	(313,197)	(256,268)	(50,684)	(54,763)
Net amount recognized	$(315,227)	$(258,252)	$ (50,775)	$ (54,884)
Amounts Recognized in Regulatory Assets Consist of:				
Net actuarial loss	$ 323,924	$ 275,417	$ 8,458	$ 5,481
Prior service cost	5,819	7,872	17,065	19,219
Transition obligation	—	—	8,148	12,060
Net amount recognized	$ 329,743	$ 283,289	$ 33,671	$ 36,760

As of December 31,	Pension Benefits 2010	Pension Benefits 2009	Post-retirement Benefits 2010	Post-retirement Benefits 2009
	(Dollars in Thousands)			
Pension Plans With a Projected Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$747,460	$662,495	$ —	$ —
Fair value of plan assets	432,233	404,243	—	—
Pension Plans With an Accumulated Benefit Obligation In Excess of Plan Assets:				
Accumulated benefit obligation	$635,541	$559,021	—	—
Fair value of plan assets	432,233	404,243	—	—
Post-retirement Plans With an Accumulated Post-retirement Benefit Obligation In Excess of Plan Assets:				
Accumulated post-retirement benefit obligation	$ —	$ —	$137,759	$128,998
Fair value of plan assets	—	—	86,984	74,114
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Benefit Obligation:				
Discount rate	5.35%	5.95%	5.00%	5.65%
Compensation rate increase	4.00%	4.00%	—	—

We use a measurement date of December 31 for our pension and other post-retirement benefit plans. In addition, we use an interest rate yield curve that is constructed based on the yields of 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 prior service cost (benefit) on a straight-line basis over the average future service of the active employees (plan participants) benefiting under the plan at the time of the amendment. We amortize the net actuarial loss on a straight-line basis over the average future service of active plan participants benefiting under the plan without application of an amortization corridor.

	Pension Benefits			Post-retirement Benefits		
Year Ended December 31,	2010	2009	2008	2010	2009	2008
			(Dollars in Thousands)			
Components of Net Periodic Cost (Benefit):						
Service cost	$ 13,926	$ 12,882	$ 10,102	$ 1,526	$ 1,529	$ 1,446
Interest cost	39,391	38,162	35,792	7,083	6,917	7,637
Expected return on plan assets	(38,384)	(37,826)	(40,332)	(5,197)	(4,756)	(4,694)
Amortization of unrecognized:						
Transition obligation, net	—	—	—	3,912	3,912	3,930
Prior service costs	2,729	2,668	2,550	2,154	1,580	1,412
Actuarial loss/(gain), net	17,183	14,263	8,415	321	(38)	904
Net periodic cost before regulatory adjustment	34,845	30,149	16,527	9,799	9,144	10,635
Regulatory adjustment	(12,167)	(9,188)	—	1,868	2,280	—
Net periodic cost	$ 22,678	$ 20,961	$ 16,527	$11,667	$ 11,424	$10,635
Other Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets:						
Current year actuarial (gain)/loss	$ 65,690	$(34,610)	$218,444	$ 3,298	$(26,205)	$12,915
Amortization of actuarial (loss)/gain	(17,183)	(14,263)	(8,415)	(321)	38	(904)
Current year prior service cost	676	48	1,461	—	6,672	2,681
Amortization of prior service costs	(2,729)	(2,668)	(2,550)	(2,154)	(1,580)	(1,412)
Current year offset of Initial Transition Asset due to plan change	—	—	—	—	(76)	—
Amortization of transition obligation	—	—	—	(3,912)	(3,912)	(3,930)
Total recognized in regulatory assets	$ 46,454	$(51,493)	$208,940	$ (3,089)	$(25,063)	$ 9,350
Total recognized in net periodic cost and regulatory assets	$ 69,132	$(30,532)	$225,467	$ 8,578	$(13,639)	$19,985
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost (Benefit):						
Discount rate	5.95%	6.10%	6.25%	5.65%	6.05%	6.10%
Expected long-term return on plan assets	8.25%	8.25%	8.50%	7.75%	7.75%	7.75%
Compensation rate increase	4.00%	4.00%	4.00%	—	—	—

The estimated amounts that will be amortized from regulatory assets into net periodic cost in 2011 are as follows:

	Pension Benefits	Post-retirement Benefits
	(In Thousands)	
Actuarial loss	$23,967	$ 1,016
Prior service cost	1,213	2,156
Transition obligation	—	3,912
Total	$25,180	$ 7,084

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 portfolios. We select assumed projected rates of return for each asset class after analyzing long-term historical experience and future expectations of the volatility of the various asset classes. Based on target asset allocations for each asset class, we develop an overall expected rate of return for the portfolios, adjusted for historical and expected experience of active portfolio management results compared to benchmark returns and for the effect of expenses paid from plan assets.

The Medicare Prescription Drug Improvement and Modernization Act of 2003 (Medicare Act) introduced a prescription drug benefit under Medicare as well as a federal subsidy that will be paid to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare. We believe our retiree health care benefit plan is at least actuarially equivalent to Medicare and is, thus, eligible for the federal subsidy. However, due to plan changes effective January 1, 2010, we are no longer entitled to the federal subsidy. As a result, the subsidy did not have an effect on our accumulated post-retirement benefit obligation in 2010 or 2009 and did not impact our net period post-retirement benefit cost in 2010. For 2008, treating the future subsidy under the Medicare Act as an actuarial experience gain, as required by the guidance, decreased the accumulated post-retirement benefit obligation by approximately $4.0 million. The subsidy also decreased net periodic post-retirement benefit cost by approximately $1.9 million in 2009 and $0.5 million in 2008.

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

	As of December 31,	
	2010	2009
Health care cost trend rate assumed for next year	8.0%	8.0%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	5.0%	5.0%
Year that the rate reaches the ultimate trend rate	2018	2018

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	$ 33	$ (30)
Effect on post-retirement benefit obligation	455	(490)

Plan Assets

We manage pension and other post-retirement benefit plan assets in accordance with the prudent investor guidelines contained in the ERISA. The plans' investment strategies support the objectives of the funds, which are to earn the highest possible return on plan assets consistent with a reasonable and prudent level of risk. We delegate the management of our funds to an independent investment advisor who hires and dismisses investment managers in various asset classes based upon performance. The investment advisor strives to diversify investments across classes, sectors and manager style to minimize the risk of large losses, based upon objectives and risk tolerance specified by management, which include allowable and/or prohibited investment types. Prohibited investments include loans to the company or its officers and directors as well as investments in the company's debt or equity securities, except as may occur indirectly through investments in diversified mutual funds. In addition, we have established restrictions to reduce concentration of risk. For example, for domestic investments, no more than 5% of pension plan assets and 5% of post-retirement benefit plan assets should be invested in the securities of a single issuer, with the exception of the U.S. government and its agencies. In addition, the fund will neither acquire more than 10% of any one issuer nor acquire more than 25% of any single industry. These restrictions do not apply to the purchase of United States Government securities. We measure and monitor investment risk on an ongoing basis through quarterly investment portfolio reviews and annual liability measurements.

The target allocations for our pension plan assets are about 35% to equity securities, 54% to debt securities and the remaining 11% to other investments such as real estate securities, hedge funds and private equity investments. Our investments in equity securities include investment funds with underlying investments in domestic and foreign large-, mid- and small-cap companies, derivatives related to such holdings and private equity investments. Our investments in debt securities include core and high-yield bonds. Core bonds are comprised of investment funds with underlying investments in investment grade debt securities of corporate entities, obligations of U.S. and foreign governments and their agencies and other debt securities. High-yield bonds include investment funds with underlying investments in non-investment grade debt securities of corporate entities, obligations of foreign governments and their agencies, private debt securities and other debt securities. Real estate securities include funds invested in commercial and residential real estate properties throughout the U.S. while hedge funds include investments in a number of underlying hedge funds with wide ranging investments, including equity securities of domestic and foreign corporations, U.S. and foreign governments and their agencies, warrants, exchange-traded funds, derivative instruments and private investment funds.

The target allocations for our other post-retirement benefit plan assets are 65% to equity securities and 35% to debt securities. Our investments in equity securities include investments in domestic and foreign large-, mid- and small-cap companies. Our investments in debt securities include a core bond fund with underlying investments in investment grade debt securities of corporate entities, obligations of the U.S. government and its agencies, and cash and cash equivalents.

Similar to other assets measured at fair value, GAAP establishes a hierarchal framework for disclosing the transparency of the inputs utilized in measuring pension and other post-retirement benefit plan assets at fair value. See Note 4, “Financial and Derivative Instruments, Trading Securities, Energy Marketing and Risk Management,” for a description of the hierarchal framework.

In 2010, we changed our investment advisor for pension assets. As a result, we also changed our investment mix in an attempt to limit the volatility in our benefit obligation. The transition resulted in the sale of all of our then existing level 1 and level 2 investments and the purchase of other level 2 investments. Level 2 pension investments are held in investment funds that are measured using daily net asset values as reported by the fund managers.

We maintain certain level 3 investments in private equity, high-yield bonds, real estate securities and hedge funds that require significant unobservable market information to measure the fair value of the investments. The fair value of private equity investments is measured by utilizing both market- and income-based models, public company comparables, at cost or at the value derived from subsequent financings. Adjustments are made when actual performance differs from expected performance; when market, economic or company-specific conditions change; and when other news or events have a material impact on the security. Fair value of Level 3 debt instruments are measured using subjective market- and income-based estimates such as projected cash flows and future interest rates. To measure the fair value of real estate securities we use a combination of market- and income-based models utilizing market discount rates, projected cash flows and the estimated value into perpetuity. Hedge funds are measured at fair value using net asset values as reported by the underlying hedge fund managers.

The following table provides the fair value of our pension plan assets and the corresponding level of hierarchy as of December 31, 2010 and 2009.

As of December 31, 2010	Level 1	Level 2	Level 3	Total
		(In Thousands)		
Assets:				
Domestic equity	$ —	$117,250	$11,575	$128,825
International equity	—	44,834	—	44,834
Core bonds	—	183,361	—	183,361
High-yield bonds	—	28,819	1,200	30,019
Real estate securities	—	—	16,411	16,411
Hedge funds	—	—	25,764	25,764
Cash equivalents	—	3,019	—	3,019
Total Assets Measured at Fair Value	$ —	$377,283	$54,950	$432,233
As of December 31, 2009				
Assets:				
Domestic equity	$117,862	$ 20,663	$ 9,310	$147,835
International equity	49,122	51,583	—	100,705
Core bonds	—	72,038	—	72,038
High-yield bonds	—	19,055	22,519	41,574
Real estate securities	—	—	14,518	14,518
Commodities	—	20,719	—	20,719
Cash equivalents	—	6,854	—	6,854
Total Assets Measured at Fair Value	$166,984	$190,912	$46,347	$404,243

The following table provides a reconciliation of pension plan assets measured at fair value using significant level 3 inputs for the years ended December 31, 2010 and 2009.

	Domestic Equity	High-yield Bonds	Real Estate Securities	Hedge Funds	Net Balance
		(In Thousands)			
Balance as of December 31, 2009	$ 9,310	$ 22,519	$ 14,518	$ —	$46,347
Actual gain (loss) on plan assets:					
Relating to assets still held at the reporting date	75	(3,963)	2,117	864	(907)
Relating to assets sold during the period	—	4,325	(77)	—	4,248
Purchases, issuances and settlements	2,190	(21,681)	(147)	24,900	5,262
Balance as of December 31, 2010	$ 11,575	$ 1,200	$ 16,411	$25,764	$54,950
Balance as of January 1, 2009	$ 8,422	$ 16,993	$ 19,985	$ —	$45,400
Actual gain (loss) on plan assets:					
Relating to assets still held at the reporting date	(132)	4,991	(5,643)	—	(784)
Relating to assets sold during the period	—	535	176	—	711
Purchases, issuances and settlements	1,020	—	—	—	1,020
Balance as of December 31, 2009	$ 9,310	$ 22,519	$ 14,518	$ —	$46,347

The following table provides the fair value of our other post-retirement benefit plan assets and the corresponding level of hierarchy as of December 31, 2010 and 2009.

As of December 31, 2010	Level 1	Level 2	Level 3	Total
		(In Thousands)		
Assets:				
Domestic equity	$ —	$45,766	$ —	$45,766
International equity	—	11,280	—	11,280
Core bonds	—	29,938	—	29,938
Total Assets Measured at Fair Value	$ —	$86,984	$ —	$86,984
As of December 31, 2009				
Assets:				
Domestic equity	$ —	$38,648	$ —	$38,648
International equity	—	9,674	—	9,674
Core bonds	—	25,792	—	25,792
Total Assets Measured at Fair Value	$ —	$74,114	$ —	$74,114

Cash Flows

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

Expected Cash Flows	Pension Benefits		Post-retirement Benefits	
	To/(From) Trust	To/(From) Company Assets	To/(From) Trust	To/(From) Company Assets
		(In Millions)		
Expected contributions: 2011	$ 49.3	$ 2.0	$ 10.9	$ 0.1
Expected benefit payments:				
2011	$ (28.0)	$ (2.0)	$ (8.4)	$ (0.1)
2012	(29.2)	(2.0)	(8.6)	(0.1)
2013	(31.0)	(2.0)	(9.0)	(0.1)
2014	(33.0)	(2.1)	(9.5)	(0.1)
2015	(35.1)	(2.1)	(9.9)	(0.1)
2016 – 2020	(217.7)	(10.0)	(52.1)	(0.5)

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 invested at the direction of plan participants into one or more of the investment alternatives we provide under the plan. Our contributions totaled $7.4 million in 2010, $6.5 million in 2009 and $6.1 million in 2008.

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, 2010, awards of 4,805,179 shares of common stock had been made under the plan.

All stock-based compensation is measured at the grant date based on the fair value of the award and is recognized as an expense in the consolidated statement of income over the requisite service period. The requisite service periods range from one to ten years. The table below shows compensation expense and income tax benefits related to stock-based compensation arrangements that are included in our net income.

	Year Ended December 31,		
	2010	2009	2008
	(In Thousands)		
Compensation expense	$11,321	$5,080	$4,619
Income tax benefits related to stock-based compensation arrangements	4,481	2,011	1,830

We use RSU awards for our stock-based compensation awards. RSU awards are grants that entitle the holder to receive shares of common stock as the awards vest. These RSU awards are defined as nonvested shares and do not include restrictions once the awards have vested. There were no modifications of awards during the years ended December 31, 2010, 2009 or 2008.

RSU awards with only service requirements vest solely upon the passage of time. We measure the fair value of these RSU awards based on the market price of the underlying common stock as of the date of grant. RSU awards with only service conditions that have a graded vesting schedule are recognized as an expense in the consolidated statement of income on a straight-line basis over the requisite service period for the entire award. Nonforfeitable dividend equivalents, or the rights to receive cash equal to the value of dividends paid on Westar Energy's common stock, are paid on these RSUs awarded during the vesting period.

RSU awards with performance measures vest upon expiration of the award term. The number of shares of common stock awarded upon vesting will vary from 0% to 200% of the RSU award, with performance tied to our total shareholder return relative to the total shareholder return of our peer group. We measure the fair value of these RSU awards using a Monte Carlo simulation technique that uses the closing stock price at the valuation date and incorporates assumptions for inputs of the expected volatility and risk-free interest rates. Expected volatility is based on historical volatility over three years using daily stock price observations. The risk-free interest rate is based on treasury constant maturity yields as reported by the Federal Reserve and the length of the performance period. For the 2010 valuation, inputs for expected volatility and risk-free interest rates ranged from 25.2% to 30.1% and 0.3% to 1.4%, respectively. For these RSU awards, dividend equivalents accumulate over the vesting period and are paid in cash based on the number of shares of common stock awarded upon vesting.

During the years ended December 31, 2010, 2009 and 2008, our RSU activity for awards with only service requirements was as follows:

	As of December 31,					
	2010		2009		2008	
	Shares	Weighted-Average Grant Date Fair Value	Shares	Weighted-Average Grant Date Fair Value	Shares	Weighted-Average Grant Date Fair Value
	(Shares In Thousands)					
Nonvested balance, beginning of year	368.8	$ 21.98	727.4	$ 20.86	984.2	$ 23.11
Granted	366.4	22.14	83.5	18.33	38.7	25.46
Vested	(118.1)	24.81	(439.0)	19.43	(261.3)	28.11
Forfeited	(16.7)	22.32	(3.1)	20.63	(34.2)	35.49
Nonvested balance, end of year	600.4	21.50	368.8	21.98	727.4	20.86

Total unrecognized compensation cost related to RSU awards with only service requirements was $4.8 million as of December 31, 2010. We expect to recognize these costs over a remaining weighted-average period of 1.9 years. The total fair value of RSUs vested and distributed during the years ended December 31, 2010, 2009 and 2008, was $2.7 million, $8.8 million and $6.2 million, respectively.

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During the years ended December 31, 2010, 2009 and 2008, our RSU activity for awards with performance measures was as follows:

	As of December 31,					
	2010		2009		2008	
	Shares	Weighted-Average Grant Date Fair Value	Shares	Weighted-Average Grant Date Fair Value	Shares	Weighted-Average Grant Date Fair Value
	(Shares In Thousands)					
Nonvested balance, beginning of year	—	$ —	—	$ —	—	$ —
Granted	366.0	24.96	—	—	—	—
Vested	(4.5)	23.32	—	—	—	—
Forfeited	(13.1)	24.99	—	—	—	—
Nonvested balance, end of year	348.4	24.98	—	—	—	—

Total unrecognized compensation cost related to RSU awards with performance measures was $4.0 million as of December 31, 2010. We expect to recognize these costs over a remaining weighted-average period of 1.6 years. There were no RSUs vested and distributed during the years ended December 31, 2010, 2009 and 2008.

RSU awards that can be settled in cash upon a change in control are classified as temporary equity. As of December 31, 2010 and 2009, we had temporary equity of $3.5 million and $3.4 million, respectively, on our consolidated balance sheets. If we determine that it is probable that these awards will be settled in cash, the awards will be reclassified as a liability.

Stock options granted between 1998 and 2001 are completely vested and have expired. There were no options exercised and all remaining options were forfeited during the year ended December 31, 2010. We currently have no plans to issue new stock option awards.

Another component of the LTISA Plan is the Executive Stock for Compensation program under which, in the past, eligible employees were entitled to receive deferred common 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 6,627 shares of common stock for dividends in 2010, 7,106 shares in 2009 and 5,283 shares in 2008. Participants received common stock distributions of 1,198 shares in 2010, 563 shares in 2009 and 530 shares in 2008.

Income tax benefits resulting from the income tax deductions in excess of the related compensation cost recognized in the financial statements is classified as cash flows from financing activities in the consolidated statements of cash flows.

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12. WOLF CREEK EMPLOYEE BENEFIT PLANS

Pension and Other Post-retirement Benefit Plans

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 other post-retirement benefit plans. KGE accrues its 47% share of Wolf Creek's cost of pension and other 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 other post-retirement benefit plans.

	Pension Benefits		Post-retirement Benefits	
As of December 31,	2010	2009	2010	2009
	(In Thousands)			
Change in Benefit Obligation:				
Benefit obligation, beginning of year	$ 111,033	$ 99,536	$ 9,574	$ 8,852
Service cost	4,144	3,643	179	188
Interest cost	6,941	6,401	519	538
Plan participants' contributions	—	—	554	439
Benefits paid	(2,799)	(2,273)	(1,045)	(1,151)
Actuarial losses	12,141	3,726	363	708
Benefit obligation, end of year	$ 131,460	$ 111,033	$ 10,144	$ 9,574
Change in Plan Assets:				
Fair value of plan assets, beginning of year	$ 62,516	$ 45,201	$ —	$ —
Actual return on plan assets	10,082	12,109	—	—
Employer contribution	6,044	7,310	—	—
Benefits paid	(2,556)	(2,104)	—	—
Fair value of plan assets, end of year	$ 76,086	$ 62,516	$ —	$ —
Funded status, end of year	$ (55,374)	$ (48,517)	$ (10,144)	$ (9,574)
Amounts Recognized in the Balance Sheets Consist of:				
Current liability	$ (256)	$ (253)	$ (689)	$ (674)
Noncurrent liability	(55,118)	(48,264)	(9,455)	(8,900)
Net amount recognized	$ (55,374)	$ (48,517)	$ (10,144)	$ (9,574)
Amounts Recognized in Regulatory Assets Consist of:				
Net actuarial loss	$ 39,735	$ 34,857	$ 3,796	$ 3,709
Prior service cost	47	76	—	—
Transition obligation	52	109	115	173
Net amount recognized	$ 39,834	$ 35,042	$ 3,911	$ 3,882

	Pension Benefits		Post-retirement Benefits	
As of December 31,	2010	2009	2010	2009
	(Dollars in Thousands)			
Pension Plans With a Projected Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$ 131,460	$ 111,033	$ —	$ —
Fair value of plan assets	76,086	62,516	—	—
Pension Plans With an Accumulated Benefit Obligation In Excess of Plan Assets:				
Accumulated benefit obligation	$ 106,684	$ 90,157	—	—
Fair value of plan assets	76,086	62,516	—	—
Post-retirement Plans With an Accumulated Post-retirement Benefit Obligation In Excess of Plan Assets:				
Accumulated post-retirement benefit obligation	$ —	$ —	$ 10,144	$ 9,574
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Benefit Obligation:				
Discount rate	5.45%	6.05%	4.90%	5.50%
Compensation rate increase	4.00%	4.00%	—	—

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Wolf Creek uses a measurement date of December 31 for its pension and other post-retirement benefit plans. In addition, Wolf Creek uses an interest rate yield curve that 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 an amortization corridor.

	Pension Benefits			Post-retirement Benefits		
Year Ended December 31,	2010	2009	2008	2010	2009	2008
	(Dollars in Thousands)					
Components of Net Periodic Cost:						
Service cost	$ 4,144	$ 3,643	$ 3,421	$ 179	$ 188	$ 203
Interest cost	6,941	6,401	5,680	519	538	517
Expected return on plan assets	(5,453)	(4,976)	(4,709)	—	—	—
Amortization of unrecognized: Transition obligation, net	57	57	57	58	58	58
Prior service costs	29	43	57	—	—	—
Actuarial loss, net	2,636	2,538	1,696	276	257	231
Net periodic cost before regulatory adjustment	8,354	7,706	6,202	1,032	1,041	1,009
Regulatory adjustment	(1,498)	(945)	—	—	—	—
Net periodic cost	$ 6,856	$ 6,761	$ 6,202	$1,032	$1,041	$1,009
Other Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets:						
Current year actuarial (gain)/loss	$ 7,514	$(3,407)	$21,517	$ 363	$ 708	$ 362
Amortization of actuarial loss	(2,636)	(2,538)	(1,696)	(276)	(257)	(231)
Amortization of prior service cost	(29)	(43)	(57)	—	—	—
Amortization of transition obligation	(57)	(57)	(57)	(58)	(58)	(58)
Total recognized in regulatory assets	$ 4,792	$(6,045)	$19,707	$ 29	$ 393	$ 73
Total recognized in net periodic cost and regulatory assets	$11,648	$ 716	$25,909	$1,061	$1,434	$1,082
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost:						
Discount rate	6.05%	6.15%	6.15%	5.50%	6.05%	6.05%
Expected long-term return on plan assets	8.00%	8.00%	8.25%	—	—	—
Compensation rate increase	4.00%	4.00%	4.00%	—	—	—

We estimate that we will amortize the following amounts from regulatory assets into net periodic cost in 2011.

	Pension Benefits	Other Post-retirement Benefits
	(In Thousands)	
Actuarial loss	$ 3,664	$ 281
Prior service cost	16	—
Transition obligation	52	58
Total	$ 3,732	$ 339

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 portfolios. 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 portfolios 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, we assumed annual health care cost growth rates were as follows.

	As of December 31,	
	2010	2009
Health care cost trend rate assumed for next year	8.0%	8.0%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	5.0%	5.0%
Year that the rate reaches the ultimate trend rate	2018	2018

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	$ (8)	$ 8
Effect on the present value of the projected benefit obligation	(85)	79

Plan Assets

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 minimize the risk of large losses. Wolf Creek delegates investment management to specialists in each asset class and, where appropriate, provides the investment managers with specific guidelines, which include allowable and/or prohibited investment types. Prohibited investments include investments in the equity or debt securities of the companies that collectively own Wolf Creek or companies that control such companies, which includes our and KGE securities. Wolf Creek has also established restrictions for certain classes of plan assets including that international equity securities should not exceed 25% of total plan assets, no more than 5% of the market value of the plan assets should be invested in the common stock of one corporation and the equity investment in any one corporation should not exceed 1% of its outstanding common stock. Wolf Creek does not utilize a separate investment trust for the purpose of funding other post-retirement benefits as it does for its pension plan.

The target allocations for Wolf Creek's pension plan assets are 22% to international equity securities, 43% to domestic equity securities, 25% to debt securities, 5% to real estate securities and 5% to commodity investments. The investments in both international and domestic equity securities include investments in large-, mid- and small-cap companies, private equity funds and investment funds with underlying investments similar to those previously mentioned. The investments in debt securities include core and high-yield bonds. Core bonds include funds invested in investment grade debt securities of corporate entities, obligations of U.S. and foreign governments and their agencies, and private debt securities. High-yield bonds include a fund with underlying investments in non-investment grade debt securities of corporate entities, private placements and bank debt. Real estate securities include funds invested in commercial and residential real estate properties while commodity investments include funds invested in commodity-related instruments.

Wolf Creek's investments in equity, debt and commodity instruments are recorded at fair value using quoted market prices or valuation models utilizing observable market data when available. A portion of the investments is comprised of real estate securities that require significant unobservable market information to measure the fair value of the investments. Real estate securities are measured at fair value using a combination of market- and income-based models utilizing market discount rates, projected cash flows and the estimated value into perpetuity.

Similar to other assets measured at fair value, GAAP establishes a hierarchal framework for disclosing the transparency of the inputs utilized in measuring pension and other post-retirement benefit plan assets at fair value. From time to time, the pension and post-retirement trusts may buy and sell investments resulting in changes within the hierarchy. See Note 4, "Financial and Derivative Instruments, Trading Securities, Energy Marketing and Risk Management," for a description of the hierarchal framework.

The following table provides the fair value of KGE's 47% share of Wolf Creek's pension plan assets and the corresponding level of hierarchy as of December 31, 2010 and 2009.

As of December 31, 2010	Level 1	Level 2	Level 3	Total
		(In Thousands)		
Assets:				
Domestic equity	$31,492	$ —	$ —	$31,492
International equity	9,036	9,597	—	18,633
Core bonds	—	14,156	—	14,156
High-yield bonds	3,319	—	—	3,319
Real estate securities	—	—	3,160	3,160
Commodities	—	4,558	—	4,558
Cash equivalents	1	767	—	768
Total Assets Measured at Fair Value	$43,848	$29,078	$ 3,160	$76,086

As of December 31, 2009	Level 1	Level 2	Level 3	Total
Assets:				
Domestic equity	$24,947	$ 3,451	$ —	$28,398
International equity	8,021	4,458	—	12,479
Core bonds	—	11,864	—	11,864
High-yield bonds	3,018	—	—	3,018
Real estate securities	—	—	2,416	2,416
Commodities	—	3,594	—	3,594
Cash equivalents	1	746	—	747
Total Assets Measured at Fair Value	$35,987	$24,113	$ 2,416	$62,516

The following table provides a reconciliation of KGE's 47% share of Wolf Creek's pension plan assets measured at fair value using significant level 3 inputs for the years ended December 31, 2010 and 2009.

	Real Estate Securities
	(In Thousands)
Balance as of December 31, 2009	$ 2,416
Actual gain (loss) on plan assets:	
Relating to assets still held at the reporting date	393
Relating to assets sold during the period	(2)
Purchases, issuances and settlements	353
Balance as of December 31, 2010	$ 3,160
Balance as of January 1, 2009	$ —
Actual gain (loss) on plan assets:	
Relating to assets still held at the reporting date	(370)
Relating to assets sold during the period	6
Purchases, issuances and settlements	2,780
Balance as of December 31, 2009	$ 2,416

Cash Flows

The following table shows our expected cash flows for KGE's 47% share of Wolf Creek's pension and other post-retirement benefit plans for future years.

Expected Cash Flows	Pension Benefits		Post-retirement Benefits	
	To/(From) Trust	To/(From) Company Assets	To/(From) Trust	To/(From) Company Assets
	(In Millions)			
Expected contributions: 2011	$ 11.0	$ 0.2	$ —	$ 0.7
Expected benefit payments:				
2011	$ (2.7)	$ (0.2)	$ —	$ (0.7)
2012	(3.1)	(0.2)	—	(0.7)
2013	(3.7)	(0.2)	—	(0.8)
2014	(4.2)	(0.2)	—	(0.8)
2015	(4.9)	(0.2)	—	(0.8)
2016 – 2020	(37.8)	(1.1)	—	(4.2)

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 contributions to the plan are deposited with a trustee and invested at the direction of plan participants into one or more of the investment alternatives provided under the plan. KGE's portion of the expense associated with Wolf Creek's matching contributions was $1.1 million in 2010, $1.1 million in 2009 and $1.0 million in 2008.

13. COMMITMENTS AND CONTINGENCIES

Purchase Orders and Contracts

As part of our ongoing operations and capital expenditure program, we have purchase orders and contracts, excluding fuel, which is discussed below under "– Purchased Power and Fuel Commitments," that had an unexpended balance of approximately $671.2 million as of December 31, 2010, of which $427.7 million had been committed. The $427.7 million of commitments relates to purchase obligations issued and outstanding at year-end.

The yearly detail of the aggregate amount of required payments as of December 31, 2010, was as follows.

	Committed Amount
	(In Thousands)
2011	$ 268,496
2012	76,169
2013	47,895
Thereafter	35,164
Total amount committed	$ 427,724

Federal Clean Air Act

We must comply with the Federal 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, nitrogen oxides (NOx) and mercury. In addition, we must comply with the provisions of the Federal Clean Air Act Amendments of 1990 that require reductions in SO_2 and NOx.

Emissions from our generating facilities, including particulate matter, SO_2 and NOx, have been determined by regulation to reduce visibility by causing or contributing to regional haze. Under federal laws, such as the Clean Air Visibility Rule, and pursuant to an agreement with the Kansas Department of Health and Environment (KDHE), we are required to install and maintain controls to reduce emissions found to cause or contribute to regional haze.

Under the Federal Clean Air Act, the Environmental Protection Agency (EPA) sets National Ambient Air Quality Standards (NAAQS) for six criteria pollutants considered harmful to public health and the environment, including particulate matter, NOx, ozone and SO_2, which result from coal combustion. Areas meeting the NAAQS are designated attainment areas while those that do not meet the NAAQS are considered nonattainment areas. In 2009, KDHE proposed to designate portions of the Kansas City area nonattainment for the 8-hour ozone standard, which has the potential to impact our operations. Each state must develop a plan to bring nonattainment areas into compliance with the NAAQS. NAAQS must be reviewed by the EPA at five-year intervals.

In 2010, the EPA strengthened the NAAQS for both NOx and SO_2. We are currently evaluating what impact this could have on our operations. If we are required to install additional equipment to control emissions at our facilities, the revised NAAQS could have a material impact on our operations and consolidated financial results.

Environmental Projects

We will continue to make significant capital expenditures at our power plants to reduce regulated emissions. The amount of these expenditures could change materially depending on the timing and nature of required investments, the specific outcomes resulting from interpretation of existing regulations, new regulations, legislation and the manner in which we operate the plants. In addition to the capital investment, in the event we install new equipment, such equipment may cause us to incur significant increases in annual operating and maintenance expense and may reduce the net production, reliability and availability of the plants. The degree to which we will need to reduce emissions and the timing of when such emissions controls may be required is uncertain. Additionally, our ability to access capital markets and the availability of materials, equipment and contractors may affect the timing and ultimate amount of such capital investments.

The environmental cost recovery rider (ECRR) allows for the more timely inclusion in retail prices the costs of capital expenditures associated with environmental improvements, including those required by the Federal Clean Air Act. In order to change our prices to recognize increased operating and maintenance costs, however, we must file a general rate case with the KCC. A recent order of the KCC indicated that it may be more appropriate to recover environmental costs at La Cygne through the filing of a general rate case as opposed to the ECRR. This could increase the time between making these investments and having them reflected in the prices we charge our customers, as well as the amount we charge our customers. Our anticipated capital expenditures at La Cygne for environmental equipment for 2011 through 2013 are $429.1 million.

Greenhouse Gases

Under EPA regulations finalized in May 2010, known as the tailoring rule, the EPA began regulating greenhouse gas (GHG) emissions from certain stationary sources in January 2011. The regulations are being implemented pursuant to two Federal Clear Air Act programs: the Title V Operating Permit program and the program requiring a permit if undergoing construction or major modifications, which is referred to as the Prevention of Significant Deterioration program (PSD). Obligations relating to Title V permits will include recordkeeping and monitoring requirements. With respect to PSD permits, projects that cause a significant increase in GHG emissions (currently defined to be more than 75,000 tons or more per year or 100,000 tons or more per year, depending on various factors), will be required to implement best available control technology (BACT). The EPA has issued guidance on what BACT entails for the control of GHGs and individual states are now required to determine what controls are required for facilities within their jurisdiction on a case-by-case basis. We cannot at this time determine the impact of these new regulations on our operations and consolidated financial results, but we believe the cost of compliance with new regulations could be material.

Renewable Energy Standard

In May 2009, Kansas enacted legislation that mandates, among other requirements, that more energy be derived from renewable sources. In years 2011 through 2015 net renewable generation capacity must be 10% of the average peak demand for the three prior years, subject to limited exceptions. This requirement increases to 15% for years 2016 through 2019 and 20% for 2020 and thereafter. We have worked with third parties to develop approximately 300 MW of qualifying wind generation facilities, which together with the use of renewable energy credits, we expect to meet the 2011 requirement. On December 14, 2010, we announced that we reached two separate agreements with third parties, subject to regulatory approval, to purchase under 20-year supply contracts the renewable energy produced from approximately 370 MW of wind generation beginning in late 2012. We expect these agreements, along with our prior development of wind generation facilities, will satisfy our net renewable generation requirement through 2015 and contribute toward meeting the increased requirement beginning in 2016.

Manufactured Gas Sites

We have been identified as being partially responsible for remediating a number of former manufactured gas sites located in Kansas. We and KDHE entered into a consent agreement governing all future work at these sites. Under 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.

Our environmental liability for remediation of former manufactured gas sites in Missouri associated with assets we divested many years ago had been limited to $7.5 million by the terms of an environmental indemnity agreement with the purchaser of those assets. In June 2010, the purchaser agreed to reduce our maximum liability to $2.5 million, which reflects our share of the purchaser's expected remediation costs. We have settled this liability.

EPA Lawsuit

Under Section 114(a) of the Federal Clean Air Act, the EPA has been 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.

In January 2004, the EPA notified us that certain projects completed at JEC violated certain requirements of the New Source Review program. In February 2009, the Department of Justice, on behalf of the EPA, filed a lawsuit against us in U.S. District Court in the District of Kansas asserting substantially the same claims. On January 25, 2010, we announced a settlement of the lawsuit. The settlement was filed with the court, seeking its approval, and on March 26, 2010, the court entered an order approving the settlement. The settlement requires that we install a selective catalytic reduction (SCR) on one of the three JEC coal units by the end of 2014. We estimate the cost of this to be approximately $240.0 million. This amount could change materially depending on final engineering and design. Depending on the NOx emission reductions attained by the single SCR and attainable through the installation of other controls on the other two JEC coal units, we may have to install an SCR on another JEC unit by the end of 2016, if needed to meet NOx reduction targets. Recovery of costs to install these systems is subject to the approval of our regulators. We believe these costs are appropriate for inclusion in the prices we are allowed to charge our customers. We will also invest $5.0 million over six years in environmental mitigation projects that we will own. In 2009, we recorded as part of the settlement $1.0 million for environmental mitigation projects that will be owned by a qualifying third party and a $3.0 million civil penalty.

FERC Investigation

We continue to respond to a non-public investigation by FERC of our use of transmission service between July 2006 and February 2008. On May 7, 2009, FERC staff advised us that it had preliminarily concluded that we improperly used secondary network transmission service to facilitate off-system wholesale power sales in violation of applicable FERC orders and Southwest Power Pool (SPP) tariffs. FERC staff alleged we received $14.3 million of unjust profits through such activities. We sent a response to FERC staff disputing both the legal basis for its allegations and their factual underpinnings. Based on our response, FERC staff substantially revised downward its preliminary conclusions to allege that we received $3.0 million of unjust profits and failed to pay $3.2 million to the SPP for transmission service. On March 4, 2010, we sent a response to FERC staff disputing its revised conclusions. We continue to believe that our use of transmission service was in compliance with FERC orders and SPP tariffs. We are unable to predict the outcome of this investigation or its impact on our consolidated financial results, but an adverse outcome could result in refunds and fines, the amounts of which could be material, and potentially could alter the manner in which we are permitted to buy and sell energy and use transmission service.

Nuclear Decommissioning

Nuclear decommissioning is a nuclear industry term for the permanent shutdown of a nuclear power plant and the removal of radioactive components in accordance with Nuclear Regulatory Commission (NRC) requirements. The NRC will terminate a plant's license and release the property for unrestricted use when a company has reduced the residual radioactivity of a nuclear plant to a level mandated by the NRC. The NRC requires companies with nuclear plants to prepare formal financial plans to fund nuclear decommissioning. These plans are designed so that 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 site 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 including the estimated costs to decommission the plant. Phase two involves the review and approval by the KCC of a "funding schedule" prepared 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 decommissioning costs.

The KCC approved Wolf Creek's most recent nuclear decommissioning site study in August 2009. Based on the study, our share of decommissioning costs, including decontamination, dismantling and site restoration, is estimated to be $279.0 million. This amount compares to the prior site study estimate of $243.3 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 and technologies as well as changes in costs for labor, materials and equipment.

We are allowed to recover nuclear decommissioning costs in our prices over a period equal to the operating license of Wolf Creek, which is through 2045. The NRC requires that funds sufficient to meet nuclear decommissioning obligations be held in trust. We believe that the KCC approved funding level will also be sufficient to meet the NRC requirement. Our consolidated financial results would be materially adversely affected if we were not allowed to recover in our prices the full amount of the funding requirement.

We recovered in our prices and deposited in an external trust fund for nuclear decommissioning approximately $3.1 million in 2010 and $2.9 million in both 2009 and 2008. We record our investment in the NDT fund at fair value, which approximated $127.0 million as of December 31, 2010, and $112.3 million as of December 31, 2009.

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. 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, calculated as one-tenth of a cent for each kilowatt-hour of net nuclear generation delivered to customers, was $4.0 million in 2010, $3.7 million in 2009 and $3.5 million in 2008. We include these costs in fuel and purchased power expense on our consolidated statements of income.

In March 2010, the DOE filed a motion to withdraw its application with the NRC to construct a national repository for the disposal of spent nuclear fuel and high-level radioactive waste at Yucca Mountain, Nevada, which would end the licensing process. An NRC board denied the DOE's motion to withdraw its application in June 2010 and the DOE appealed that decision to the full NRC in early July 2010. The NRC has not yet decided that appeal. The question of the DOE's legal authority to withdraw its license application also is pending in multiple lawsuits filed with a federal appellate court. Oral argument to the court is set for late March 2011. Wolf Creek has an on-site storage facility designed to hold all spent fuel generated at the plant through 2025 and believes it will be able to expand on-site storage as needed past 2025. We cannot predict when, or if, an alternative disposal site will be available to receive Wolf Creek's spent nuclear fuel and will continue to monitor this activity.

Nuclear Insurance

We maintain nuclear insurance for Wolf Creek in four areas: liability, worker radiation, property and accidental outage. These policies contain certain industry standard exclusions, including, but not limited to, ordinary wear and tear and war. The nuclear liability and property insurance programs subscribed to by members of the nuclear power generating industry no longer include industry aggregate limits for non-certified acts, as defined by the Terrorism Risk Insurance Act, of terrorism-related losses, including replacement power costs. An industry aggregate limit of $3.2 billion plus any reinsurance recoverable by Nuclear Electric Insurance Limited (NEIL), our insurance provider, exists for property claims, including accidental outage power costs, for acts of terrorism affecting Wolf Creek or any other nuclear energy facility property policy within twelve months from the date of the first act. These limits are the maximum amount to be paid to members who sustain losses or damages from these types of terrorist acts. In addition, industry-wide retrospective assessment programs (discussed below) can apply once these insurance programs have been exhausted.

Nuclear Liability Insurance

Pursuant to the Price-Anderson Act, which has been reauthorized through December 31, 2025, by the Energy Policy Act of 2005, we are required to insure against public liability claims resulting from nuclear incidents to the full limit of public liability, which is currently approximately $12.6 billion. This limit of liability consists of the maximum available commercial insurance of $375.0 million, and the remaining $12.2 billion is provided through mandatory participation in an industry-wide retrospective assessment program. Under this retrospective assessment program, the owners of Wolf Creek are jointly and severally subject to an assessment of up to $117.5 million (our share is $55.2 million), payable at no more than $17.5 million (our share is $8.2 million) per incident per year per reactor. Both the total and yearly assessment is subject to an inflation adjustment based on the Consumer Price Index and applicable premium taxes. This assessment also applies in excess of our worker radiation claims insurance. The next scheduled inflation adjustment is scheduled for August 2013. In addition, Congress could impose additional revenue-raising measures to pay claims.

Nuclear Property Insurance

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

Accidental Nuclear Outage Insurance

The owners also carry additional insurance with NEIL to cover costs of replacement power and other extra expenses incurred during a prolonged outage resulting from accidental property damage at Wolf Creek. If significant losses were incurred at any of the nuclear plants insured under the NEIL policies, we may be subject to retrospective assessments under the current policies of approximately $26.2 million (our share is $12.3 million).

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

Fuel and Purchased Power Commitments

To supply a portion of the fuel requirements for our power plants, the owners of Wolf Creek have entered into various commitments to obtain nuclear fuel and we have entered into various commitments to obtain coal and natural gas. Some of these contracts contain provisions for price escalation and minimum purchase commitments. As of December 31, 2010, our share of Wolf Creek's nuclear fuel commitments was approximately $45.3 million for uranium concentrates expiring in 2017, $6.9 million for conversion expiring in 2017, $116.6 million for enrichment expiring in 2024 and $44.7 million for fabrication expiring in 2024.

As of December 31, 2010, our coal and coal transportation contract commitments in 2010 dollars under the remaining terms of the contracts were approximately $1.5 billion. The two largest contracts expire in 2013 and 2020, with the remaining contracts expiring at various times through 2020.

As of December 31, 2010, our natural gas transportation contract commitments in 2010 dollars under the remaining terms of the contracts were approximately $179.8 million. The natural gas transportation contracts provide firm service to several of our natural gas burning facilities and expire at various times through 2030.

We have purchase power agreements with the owners of two separate wind generation facilities located in Kansas with a combined capacity of 146 MW. The agreements expire in late 2028 and early 2029 and provide for our receipt and purchase of the energy produced at a fixed price per unit of output. We estimate that our annual cost for energy purchased from these wind generation facilities will be approximately $19.5 million.

14. ASSET RETIREMENT OBLIGATIONS

Legal Liability

We have recognized legal obligations associated with the disposal of long-lived assets that result from the acquisition, construction, development or normal operation of such assets. The recording of AROs for regulated operations has no income statement impact due to the deferral of the adjustments through the establishment of a regulatory asset.

We initially recorded AROs at fair value for the estimated cost to decommission Wolf Creek (KGE's 47% share), retire our wind generating facilities, 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 AROs included on our consolidated balance sheets in long-term liabilities.

	As of December 31,	
	2010	2009
	(In Thousands)	
Beginning ARO	$119,519	$ 95,083
Liabilities incurred	—	1,289
Liabilities settled	(738)	(1,922)
Accretion expense	7,218	4,727
Increase in nuclear decommissioning ARO liability	—	20,342
Ending ARO	$125,999	$119,519

As discussed in Note 13, "Commitments and Contingencies – Nuclear Decommissioning," Wolf Creek filed a nuclear decommissioning study with the KCC in 2009. As a result of the study, we recorded a $20.3 million increase in our ARO to reflect revisions to the estimated costs to decommission Wolf Creek.

Conditional ARO refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. We determined that our conditional AROs include the retirement of our wind generation facilities, disposal of asbestos insulating material at our power plants, the remediation of ash disposal ponds and the disposal of PCB-contaminated oil.

We have an obligation to retire our wind generation facilities and remove the foundations. The ARO related to our wind generation facilities was determined based upon the date each wind generation facility was placed into service.

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

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

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

Non-Legal Liability – Cost of Removal

We recover in our prices the costs to dispose of plant assets that do not represent legal retirement obligations. As of December 31, 2010 and 2009, we had $70.3 million and $68.1 million, respectively, in amounts collected, but not yet spent, for removal costs classified as a regulatory liability.

15. LEGAL PROCEEDINGS

In late 2002, one of our former executive officers resigned from his position and another executive officer was placed on administrative leave from his position. Following the completion of an investigation and the publication of a report prepared by a special committee of our board of directors, our board of directors determined that their employment was terminated for cause. In June 2003, we filed a demand for arbitration with the American Arbitration Association asserting claims against them arising out of their previous employment and seeking to avoid payment of compensation not yet paid to them under various plans and agreements. They filed counterclaims against us alleging substantial damages related to the termination of their employment and the publication of the report of the special committee. As of December 31, 2010, we had accrued liabilities of $80.6 million for compensation not yet paid to them and $8.3 million for legal fees and expenses they had incurred. As of December 31, 2009, we had accrued liabilities of $77.6 million for compensation not yet paid to them and $6.8 million for legal fees and expenses they had incurred. The arbitration was stayed in August 2004 pending final resolution of criminal charges filed by the United States Attorney’s Office against them in U.S. District Court in the District of Kansas. In August 2010, these criminal charges were dismissed and subsequently the stay of the arbitration was lifted. We expect arbitration proceedings to conclude in 2011. We have reclassified about $54.0 million, comprised of various elements of compensation, from other long-term liabilities to other current liabilities on our consolidated balance sheet. We intend to vigorously defend against the counterclaims they filed in the arbitration. We are unable to predict the ultimate amount of the compensation, legal fees or related amounts we may be required to pay them, or the ultimate impact of these matters on our consolidated financial results.

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

See also Note 3, “Rate Matters and Regulation,” and Note 13, “Commitments and Contingencies.”

16. 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, 2007	214,363	95,463,180
Issuance of common stock	—	12,847,955
Balance at December 31, 2008	214,363	108,311,135
Issuance of common stock	—	760,865
Balance at December 31, 2009	214,363	109,072,000
Issuance of common stock	—	3,056,068
Balance at December 31, 2010	214,363	112,128,068

Westar Energy's articles of incorporation, as amended, provide for 150,000,000 authorized shares of common stock. As of December 31, 2010, we had 112,128,068 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 2010, 2009 and 2008, Westar Energy issued 734,918 shares, 760,865 shares and 592,772 shares, respectively, through the DSPP and other stock-based plans operated under the 1996 LTISA Plan. As of December 31, 2010 and 2009, a total of 2,590,942 shares and 3,196,816 shares, respectively, were available under the DSPP registration statement.

Common Stock Issuance

Through a Sales Agency Financing Agreement entered into with a broker dealer subsidiary of a bank in 2007, Westar Energy sold 1.2 million shares of common stock for $25.0 million in 2010 and 1.1 million shares of common stock for $26.9 million in 2008. Westar Energy did not sell any shares of common stock under this agreement during 2009.

During 2010, Westar Energy entered into two separate forward sale agreements with banks. The use of a forward sale agreement allows Westar Energy the means to minimize equity market uncertainty by pricing a common stock offering under then existing market conditions while mitigating share dilution by postponing the issuance of common stock until funds are needed. Westar Energy is also better able to match the timing of its financing needs with its capital investment and regulatory plans. The forward sale transactions are entered into at market prices; therefore, the forward sale agreements have no initial fair value. Westar Energy will not receive any proceeds from the sale of common stock under the forward sale agreements until transactions are settled. Upon settlement, Westar Energy will record the forward sale agreements within equity. Except in specified circumstances or events that would require physical share settlement, Westar Energy is able to elect to settle any forward sale transactions by means of physical share, cash or net share settlement, and is also able to elect to settle the forward sale transactions in whole, or in part, earlier than the stated maturity dates. Currently, Westar Energy anticipates settling the forward sale transactions through physical share settlement. The shares under the forward sale agreements were initially priced when the agreements were entered into and are subject to certain fixed pricing adjustments during the term of the agreements. Accordingly, assuming physical share settlement, Westar's net proceeds from the forward sale transactions will represent the prices established by the forward sale agreements applicable to the time periods in which physical settlement occurs.

Westar Energy entered into one such forward sale agreement on November 4, 2010. Under the terms of the agreement, the bank, as forward seller, borrowed 7.5 million shares of Westar Energy's common stock from third parties and sold them to a group of underwriters for $25.54 per share. Under an over-allotment option included in the agreement, the underwriters purchased approximately 1.0 million additional shares on November 5, 2010, also for $25.54 per share, which increased the total number of shares under the forward sale agreement to approximately 8.5 million shares. The underwriters receive a commission equal to 3.5% of the sales price of all shares sold under the agreement. Westar Energy must settle the forward sale agreement within 18 months of the transaction date. Assuming physical share settlement of this agreement at December 31, 2010, Westar Energy would have received aggregate proceeds of approximately $206.2 million, net of commission, based on an average forward price of $24.32 per share.

On April 2, 2010, Westar Energy entered into a new, three-year Sales Agency Financing Agreement and forward sale agreement. The maximum amount that Westar Energy may offer and sell under the agreements is the lesser of an aggregate of $500.0 million or approximately 22.0 million shares, subject to adjustment for share splits, share combinations and share dividends. Under the terms of the Sales Agency Financing Agreement, Westar Energy may offer and sell shares of its common stock from time to time through the broker dealer subsidiary, as agent. The broker dealer receives a commission equal to 1% of the sales price of all shares sold under the agreement. In addition, under the terms of the Sales Agency Financing Agreement and forward sale agreement, Westar Energy may from time to time enter into one or more forward sale transactions with the bank, as forward purchaser, and the bank will borrow shares of Westar Energy's common stock from third parties and sell them through its broker dealer. Westar Energy must settle the forward sale transactions within a year of the date each transaction is entered. As of December 31, 2010, Westar Energy had entered into forward sale transactions with respect to an aggregate of approximately 5.4 million shares of common stock. As partial settlement of the forward sale transactions, Westar Energy delivered approximately 0.5 million shares of common stock for proceeds of $10.4 million on October 14, 2010. On December 20, 2010, Westar Energy delivered approximately 0.7 million additional shares for proceeds of $16.0 million as partial settlement of the forward sale transactions. Assuming physical share settlement of the approximately 4.2 million remaining shares of common stock at December 31, 2010, Westar Energy would have received aggregate proceeds of approximately $94.0 million, net of commission, based on an average forward price of $22.16 per share.

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

In 2008, Westar Energy also completed a forward sale agreement entered into in November 2007 by delivering 5.1 million shares of common stock for proceeds of $123.0 million.

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

Preferred Stock Not Subject to Mandatory Redemption

Westar Energy's cumulative preferred stock is redeemable in whole or in part on 30 to 60 days' notice at our option. The table below shows our redemption amount for all series of preferred stock not subject to mandatory redemption as of December 31, 2010.

Rate	Shares	Principal Outstanding	Call Price	Premium	Total Cost to Redeem
		(Dollars in Thousands)			
4.500%	121,613	$ 12,161	108.0%	$ 973	$ 13,134
4.250%	54,970	5,497	101.5%	82	5,579
5.000%	37,780	3,778	102.0%	76	3,854
		$ 21,436		$ 1,131	$ 22,567

The provisions of Westar Energy's articles of incorporation, as amended, contain restrictions on the payment of dividends or the making of other distributions on its common stock while any preferred shares remain outstanding unless certain capitalization ratios and other conditions are met. If the ratio of the capital represented by Westar Energy's common stock, including premiums on its capital stock and its surplus accounts, to its total capital and its surplus accounts at the end of the second month immediately preceding the date of the proposed payment of dividends, adjusted to reflect the proposed payment (capitalization ratio), will be less than 20%, then the payment of the dividends on its common stock, including the proposed payment, during the 12-month period ending with and including the date of the proposed payment shall not exceed 50% of its net income available for dividends for the 12-month period ending with and including the second month immediately preceding the date of the proposed payment. If the capitalization ratio is 20% or more but less than 25%, then the payment of dividends on its common stock, including the proposed payment, during the 12-month period ending with and including the date of the proposed payment shall not exceed 75% of its net income available for dividends for the 12-month period ending with and including the second month immediately preceding the date of the proposed payment. Except to the extent permitted above, no payment or other distribution may be made that would reduce the capitalization ratio to less than 25%. The capitalization ratio is determined based on the unconsolidated balance sheet for Westar Energy. As of December 31, 2010, 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.

17. VARIABLE INTEREST ENTITIES

Effective January 1, 2010, we adopted accounting guidance that amends the consolidation criteria for VIEs. The amended guidance requires a qualitative assessment rather than a quantitative assessment in determining the primary beneficiary of a VIE. A qualitative assessment includes understanding the entity's purpose and design, including the nature of the entity's activities and the risks that the entity was designed to create and pass through to its variable interest holders. A reporting enterprise is deemed to be the primary beneficiary of a VIE if it has (a) the power to direct the activities of the VIE that most significantly impact the VIE's economic performance and (b) the obligation to absorb losses or right to receive benefits from the VIE that could potentially be significant to the VIE. The primary beneficiary of a VIE is required to consolidate the VIE. We have concluded that trusts holding assets we lease, which include the 8% interest in JEC, the 50% interest in La Cygne unit 2 and railcars we use to transport coal to some of our plants, are VIEs of which we are the primary beneficiary. With the consolidation of these VIEs, we ceased accounting for these transactions as leases. See Note 18, "Leases," for additional information.

We assess all entities with which we become involved to determine whether such entities are VIEs and, if so, whether or not we are the primary beneficiary of such entities. We also continuously assess whether we are the primary beneficiary of the VIEs with which we are involved. Prospective changes in facts and circumstances may cause us to reconsider our determination as it relates to the identification of the primary beneficiary.

8% Interest in Jeffrey Energy Center

Under an agreement that expires in January 2019, we lease an 8% interest in JEC from a trust. The trust was financed with an equity contribution from an owner participant and debt issued by the trust. The trust was created specifically to purchase the 8% interest in JEC and lease it to a third party, and does not hold any other assets. We meet the requirements to be considered the primary beneficiary of the trust. In determining the primary beneficiary of the trust, we concluded that the activities of the trust that most significantly impact its economic performance and that we have the power to direct include (1) the operation and maintenance of the 8% interest in JEC, (2) our ability to exercise a purchase option at the end of the agreement at the lesser of fair value or a fixed amount and (3) our option to require refinancing of the trust's debt. We have the potential to receive benefits from the trust that could potentially be significant if the fair value of the 8% interest in JEC at the end of the agreement is greater than the fixed amount. The possibility of lower interest rates upon refinancing the debt also creates the potential for us to receive significant benefits.

50% Interest in La Cygne Unit 2

Under an agreement that expires in September 2029, KGE entered into a sale-leaseback transaction with a trust under which the trust purchased KGE's 50% interest in La Cygne unit 2 and subsequently leased it back to KGE. The trust was financed with an equity contribution from an owner participant and debt issued by the trust. The trust was created specifically to purchase the 50% interest in La Cygne unit 2 and lease it back to KGE, and does not hold any other assets. We meet the requirements to be considered the primary beneficiary of the trust. In determining the primary beneficiary of the trust, we concluded that the activities of the trust that most significantly impact its economic performance and that we have the power to direct include (1) the operation and maintenance of the 50% interest in La Cygne unit 2, (2) our ability to exercise a purchase option at the end of the agreement at the lesser of fair value or a fixed amount and (3) our option to require refinancing of the trust's debt. We have the potential to receive benefits from the trust that could potentially be significant if the fair value of the 50% interest in La Cygne unit 2 at the end of the agreement is greater than the fixed amount. The possibility of lower interest rates upon refinancing the debt also creates the potential for us to receive significant benefits.

Railcars

Under two separate agreements that expire in May 2013 and November 2014, we lease railcars from trusts to transport coal to some of our power plants. The trusts were financed with equity contributions from owner participants and debt issued by the trusts. The trusts were created specifically to purchase the railcars and lease them to us, and do not hold any other assets. We meet the requirements to be considered the primary beneficiary of the trusts. In determining the primary beneficiary of the trusts, we concluded that the activities of the trusts that most significantly impact their economic performance and that we have the power to direct include the operation, maintenance and repair of the railcars and our ability to exercise a purchase option at the end of the agreements at the lesser of fair value or a fixed amount. We have the potential to receive benefits from the trusts that could potentially be significant if the fair value of the railcars at the end of the agreements is greater than the fixed amounts. Our agreements with these trusts also include renewal options during which time we would pay a fixed amount of rent. We have the potential to receive benefits from the trusts during the renewal periods if the fixed amount of rent is less than the amount we would be required to pay under a new agreement.

Financial Statement Impact

As of December 31, 2010, we had recorded the following assets and liabilities on our consolidated balance sheet as a result of consolidating the VIEs described above.

As of December 31, 2010		Dollar Amount (In Thousands)
Assets:		
Property, plant and equipment of variable interest entities, net	$	345,037
Regulatory assets (a)		3,963
Liabilities:		
Current maturities of long-term debt of variable interest entities	$	30,155
Accrued interest (b)		5,064
Long-term debt of variable interest entities, net		278,162

(a) Included in other regulatory assets on our consolidated balance sheet.
(b) Included in accrued interest on our consolidated balance sheet.

All of the liabilities noted in the table above relate to the purchase of the reported property, plant and equipment. The assets of the VIEs can be used only to settle obligations of the VIEs and the VIEs' debt holders have no recourse to our general credit. We have not provided financial or other support to the VIEs and are not required to provide such support. We did not record any gain or loss upon initial consolidation of the VIEs.

Additionally, the consolidation of these VIEs affected the presentation of our consolidated statements of cash flows. A portion of lease expenditures previously presented as operating cash flows is now allocated between operating and financing cash flows. Total cash flows did not change.

18. LEASES

As discussed in Note 17, "Variable Interest Entities," the adoption of new accounting guidance effective January 1, 2010, eliminated the lease accounting we previously reported for our 8% interest in JEC, our 50% interest in La Cygne unit 2 and railcars we use to transport coal to some of our plants. As a result, future commitments under operating leases, minimum annual rental payments under capital leases and recorded capital lease assets have decreased significantly. However, we remain contractually obligated to meet our future commitments and to make annual payments in accordance with the lease agreements that relate to these assets.

Operating Leases

We lease office buildings, computer equipment, vehicles, railcars and other property and equipment. These leases have various terms and expiration dates ranging from one to 20 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 and estimated future commitments under operating leases are as follows.

Year Ended December 31,	Total Operating Leases
	(In Thousands)
Rental expense:	
2008	$ 38,870
2009	38,096
2010	15,464
Future commitments:	
2011	$ 12,940
2012	14,192
2013	11,973
2014	9,996
2015	7,879
Thereafter	21,936
Total future commitments	$ 78,916

Capital Leases

We identify capital leases based on defined criteria. 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 two to seven years depending on the type of vehicle. Computer equipment has a lease term of four to five years.

Assets recorded under capital leases are listed below.

	December 31, 2010	December 31, 2009
	(In Thousands)	
Vehicles	$12,504	$ 18,991
Computer equipment and software	5,551	4,640
JEC 8% interest (a)	—	118,623
Accumulated amortization	(8,744)	(21,736)
Total capital leases	$ 9,311	$120,518

(a) As discussed in Note 17, “Variable Interest Entities,” the adoption of new accounting guidance effective January 1, 2010, eliminated the lease accounting we previously reported for our 8% interest in JEC.

Capital lease payments are 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)
2011	$ 2,110
2012	2,213
2013	1,908
2014	1,792
2015	1,391
Thereafter	1,157
	10,571
Amounts representing imputed interest	(1,260)
Present value of net minimum lease payments under capital leases	9,311
Less: current portion	1,797
Total long-term obligation under capital leases	$ 7,514

19. DISCONTINUED OPERATIONS — Sale of Protection One, Inc.

In January 2009, the Joint Committee on Taxation of the U.S. Congress approved a settlement with the IRS Office of Appeals regarding the re-characterization of a portion of the loss we incurred on the sale of Protection One, Inc. (Protection One), a former subsidiary, from a capital loss to an ordinary loss. The settlement involved a determination of the amount of the net capital loss and net operating loss carryforwards available as of December 31, 2004, to offset income in years after 2004. In March 2009, we filed amended federal income tax returns for years 2005, 2006 and 2007 to claim a portion of the income tax benefits from the net operating loss carryforward. We expect to realize the remainder of the income tax benefits from the net operating loss carryforward in future years. We recorded a non-cash net earnings benefit of approximately $33.7 million, net of $22.8 million we paid Protection One, in discontinued operations in 2009 in recognition of this settlement.

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20. QUARTERLY RESULTS (UNAUDITED)

Our electric business is seasonal in nature and, in our opinion, comparisons between the quarters of a year do not give a true indication of overall trends and changes in operations.

2010	First	Second	Third (a)	Fourth
	(In Thousands, Except Per Share Amounts)			
Revenues (b)	$459,830	$495,181	$644,437	$456,723
Net income (b)	31,682	54,530	115,863	6,550
Net income attributable to common stock (b)	30,438	53,069	114,502	4,919
Per Share Data (b):				
Basic:				
Earnings available	$ 0.27	$ 0.47	$ 1.02	$ 0.04
Diluted:				
Earnings available	$ 0.27	$ 0.47	$ 1.01	$ 0.04
Cash dividend declared per common share	$ 0.31	$ 0.31	$ 0.31	$ 0.31
Market price per common share:				
High	$ 22.78	$ 23.93	$ 24.64	$ 25.90
Low	$ 20.56	$ 21.08	$ 21.22	$ 24.21

(a) In the third quarter of 2010, net income and net income attributable to common stock increased compared to the same period last year due principally to warmer than normal weather in our service territory paired with extremely cool weather during the third quarter of 2009. As measured by cooling degree days, the weather during the third quarter of 2010 was 63% warmer than the same period last year and 20% warmer than the 20-year average.

(b) 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.

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2009	First (a)	Second	Third	Fourth (a)
	(In Thousands, Except Per Share Amounts)			
Revenues (b)	$421,767	$467,812	$528,534	$ 440,118
Net income (b)	44,164	38,386	81,142	11,384
Results of discontinued operations, net of tax	32,978	—	—	767
Net income attributable to common stock (b)	43,922	38,144	80,900	11,142
Per Share Data (b):				
Basic:				
Earnings available	$ 0.40	$ 0.35	$ 0.73	$ 0.10
Diluted:				
Earnings available	$ 0.40	$ 0.35	$ 0.73	$ 0.10
Cash dividend declared per common share	$ 0.30	$ 0.30	$ 0.30	$ 0.30
Market price per common share:				
High	$ 21.10	$ 19.32	$ 21.56	$ 22.30
Low	$ 14.86	$ 16.60	$ 17.91	$ 18.91

(a) In the first and fourth quarters of 2009, we recognized net earnings benefits from discontinued operations of approximately $33.0 million and $0.8 million, respectively, due to the re-characterization of a portion of the loss we incurred on the sale of Protection One, a former subsidiary, from a capital loss to an ordinary loss.

(b) 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.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

We maintain a set of disclosure controls and procedures designed to ensure that information required to be disclosed in reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms. In addition, the disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in reports under the Act is accumulated and communicated to management, including the chief executive officer and the chief financial officer, allowing timely decisions regarding required disclosure. As of the end of the period covered by this report, based on an evaluation carried out under the supervision and with the participation of management, including the chief executive officer and the chief financial officer, of the effectiveness of our disclosure controls and procedures, the chief executive officer and the chief financial officer have concluded that our disclosure controls and procedures were effective.

There were no changes in our internal control over financial reporting during the three months ended December 31, 2010, 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 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 2011 Annual Meeting of Shareholders to be filed pursuant to Regulation 14A (2011 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 2011 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 2011 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 2011 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 2011 Proxy Statement under the captions "Beneficial Ownership of Voting Securities" and " Equity Compensation Plan Information," and that information is incorporated by reference in this Form 10-K.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The information required by Item 13 will be set forth in our 2011 Proxy Statement under the caption "Corporate Governance Matters," and that information is incorporated by reference in this Form 10-K.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by Item 14 will be set forth in our 2011 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, 2010 and 2009
Consolidated Statements of Income for the years ended December 31, 2010, 2009 and 2008
Consolidated Statements of Cash Flows for the years ended December 31, 2010, 2009 and 2008
Consolidated Statements of Changes in Equity for the years ended December 31, 2010, 2009 and 2008
Notes to Consolidated Financial Statements

SCHEDULES

Schedule II – Valuation and Qualifying Accounts

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

EXHIBIT INDEX

All exhibits marked "I" are incorporated herein by reference. All exhibits marked by an asterisk are management contracts or compensatory plans or arrangements required to be identified by Item 15(a)(3) of Form 10-K. All exhibits marked "#" are filed with this Form 10-K.

	Description	
1(a)	-Underwriting Agreement between Westar Energy, Inc., and Citigroup Global Markets Inc. and Lehman Brothers Inc., as representatives of the several underwriters, dated January 12, 2005 (filed as Exhibit 1.1 to the Form 8-K filed on January 18, 2005)	I
1(b)	-Underwriting Agreement between Westar Energy, Inc. and Barclays Capital and Citigroup Global Markets, Inc., as representatives of the several underwriters, dated June 27, 2005 (filed as Exhibit 1.1 to the Form 8-K filed on July 1, 2005)	I
1(c)	-Sales Agency Financing Agreement, dated as of April 12, 2007, between Westar Energy, Inc. and BNY Capital Markets, Inc. (filed as Exhibit 1.1 to the Form 8-K filed on April 12, 2007)	I
1(d)	-Sales Agency Financing Agreement, dated as of August 24, 2007, between Westar Energy, Inc. and BNY Capital Markets, Inc. (filed as Exhibit 1.1 to the Form 8-K filed on August 27, 2007)	I
1(e)	-Underwriting Agreement, dated November 15, 2007, among UBS Securities LLC and J.P. Morgan Securities Inc., as representatives of the underwriters named therein, UBS Securities LLC, in its capacity as agent for UBS AG, London Branch, and Westar Energy, Inc. (filed as Exhibit 1.1 to the Form 8-K filed on November 16, 2007)	I
1(f)	- Underwriting Agreement, dated May 29, 2008, among Citigroup Global Markets Inc., Banc of America Securities LLC and UBS Securities LLC, as representatives of the underwriters named therein, and Westar Energy, Inc. (filed as Exhibit 1.1 to the Form 8-K filed on June 4, 2008)	I
1(g)	-Underwriting Agreement, dated November 18, 2008, among J.P. Morgan Securities Inc. and Deutsche Bank Securities Inc., as representatives of the underwriters named therein, and Westar Energy, Inc. (filed as Exhibit 1.1 to the Form 8-K filed on November 24, 2008)	I
1(h)	-Sales Agency Financing Agreement, dated as of April 2, 2010, by and among Westar Energy, Inc., BNY Mellon Capital Markets, LLC and The Bank of New York Mellon (filed as Exhibit 1.3 to the Form S-3 filed on April 2, 2010)	I
1(i)	- Underwriting Agreement, dated November 4, 2010, among J.P. Morgan Securities LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc. and Wells Fargo Securities, LLC, as representatives of the underwriters named therein, and Westar Energy, Inc. (filed as Exhibit 1.1 to the Form 8-K filed on November 8, 2010)	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

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4(u)	-Forty-Fifth Supplemental Indenture dated March 17, 2006 between Kansas Gas and Electric Company and BNY Midwest Trust Company, as Trustee, to the Kansas Gas and Electric Company Mortgage and Deed of Trust dated April 1, 1940 (filed as Exhibit 4.1 to the Form 8-K filed on March 21, 2006)	I
4(v)	-Forty-Sixth Supplemental Indenture dated June 1, 2006 between Kansas Gas and Electric Company and BNY Midwest Trust Company, as Trustee, to the Kansas Gas and Electric Company Mortgage and Deed of Trust dated April 1, 1940 (filed as Exhibit 4 to the Form 10-Q for the period ended June 30, 2006 filed on August 9, 2006)	I
4(w)	-Fortieth Supplemental Indenture dated May 15, 2007, between Westar Energy, Inc. and The Bank of New York Trust Company, N.A. (as successor to Harris Trust and Savings Bank) to its Mortgage and Deed of Trust dated July 1, 1939 (filed as Exhibit 4.16 to the Form 8-K filed on May 16, 2007)	I
4(x)	-Forty-Eighth Supplemental Indenture, dated as of July 10, 2007, by and among Kansas Gas and Electric Company, The Bank of New York Trust Company, N.A. and Judith L. Bartolini (filed as Exhibit 4(x) to the Form 10-K for the period ended December 31, 2007 filed on February 29, 2008)	I
4(y)	-Bond Purchase Agreement, dated as of August 14, 2007, between Kansas Gas and Electric Company and Nomura International PLC (filed as Exhibit 4.1 to the Form 8-K filed on August 15, 2007)	I
4(z)	-Forty-Ninth Supplemental Indenture, dated as of October 12, 2007, by and among Kansas Gas and Electric Company, The Bank of New York Trust Company, N.A. and Judith L. Bartolini (filed as Exhibit 4.1 to the Form 8-K filed on October 19, 2007)	I
4(aa)	-Form of First Mortgage Bonds, 6.10% Series Due 2047 (contained in Exhibit 4(w))	I
4(ab)	-Bond Purchase Agreement dated as of May 15, 2008, between Kansas Gas and Electric Company and the Purchasers named therein (filed as Exhibit 4(1) to the Form 8-K filed on May 16, 2008)	I
4(ac)	-Fifty-First Supplemental Indenture, dated as of May 15, 2008 by and among Kansas Gas and Electric Company, The Bank of New York Trust Company, N.A. and Judith L. Bartolini (filed as Exhibit 4(2) to the Form 8-K filed on May 16, 2008)	I
4(ad)	-Fifty-Second Supplemental Indenture, dated as of August 1, 2008 by and among Kansas Gas and Electric Company, The Bank of New York Mellon Trust Company, N.A. and Judith L. Bartolini (filed as Exhibit 4(c) to the Form 10-Q for the period ended September 30, 2008 filed on November 6, 2008)	I
4(ae)	-Fifty-Third Supplemental Indenture, dated as of October 10, 2008 by and among Kansas Gas and Electric Company, The Bank of New York Mellon Trust Company, N.A. and Judith L. Bartolini (filed as Exhibit 4(d) to the Form 10-Q for the period ended September 30, 2008 filed on November 6, 2008)	I
4(af)	-Forty-First Supplemental Indenture, dated as of November 25, 2008 by and among Westar Energy, Inc., The Bank of New York Mellon Trust Company, N.A. and Judith L. Bartolini (filed as Exhibit 4.1 to the Form 8-K filed on November 24, 2008)	I
4(ag)	-Purchase Agreement, dated as of June 8, 2009, between Kansas Gas and Electric Company and and the Purchasers named therein (filed as Exhibit 4.1 to the Form 8-K/A filed on June 9, 2009)	I
4(ah)	-Fifty-Fourth Supplemental Indenture, dated as of June 11, 2009 by and among Kansas Gas and Electric Company, The Bank of New York Mellon Trust Company, N.A. and Judith L. Bartolini (filed as Exhibit 4(b) to the Form 10-Q for the period ended June 30, 2009 filed on August 6, 2009)	I
4(ai)	-Fifty-Fifth Supplemental Indenture, dated as of October 1, 2009 by and among Kansas Gas and Electric Company, The Bank of New York Mellon Trust Company, N.A. and Judith L. Bartolini (filed as Exhibit 4(a) to the Form 10-Q for the period ended September 30, 2009 filed on October 29, 2009)	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.	
4(aj)	-Fifty-Sixth Supplemental Indenture, dated as of February 18, 2011, by and among Kansas Gas and Electric Company, The Bank of New York Mellon Trust Company, N.A. and Richard Tarnas (filed as Exhibit 4.1 to the Form 8-K filed on February 22, 2011)	I
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 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(n)	-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(o)	-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(p)	-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(q)	-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(r)	-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(s)	-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(t)	-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(u)	-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(v)	-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(w)	-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(x)	-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(y)	-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(z)	-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(aa)	-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(ab)	-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(ac)	-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(ad)	-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(ae)	-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(af)	-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(ag)	-Deferral Election Form of William B. Moore (filed as Exhibit 10.2 to the Form 8-K filed on December 29, 2004)*	I
10(ah)	-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(ai)	-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(aj)	-Form of Change in Control Agreement (filed as Exhibit 10.1 to the Form 8-K filed on January 26, 2006)*	I
10(ak)	-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(al)	-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(am)	-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(an)	-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(ao)	-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(ap)	-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

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10(aq)	-Westar Energy, Inc. Form of Restricted Share Units Award	I
10(ar)	-Westar Energy, Inc. Form of Performance Based Restricted Share Units Award	I
10(as)	-Westar Energy, Inc. Form of First Transition Performance Based Restricted Share Units Award	I
10(at)	-Westar Energy, Inc. Form of Second Transition Performance Based Restricted Share Units Award	I
10(au)	-Form of Amended and Restated Change in Control Agreement with Officers of Westar Energy, Inc.	I
10(av)	-Westar Energy, Inc. Retirement Benefit Restoration Plan (filed as Exhibit 10.1 to the Form 8-K filed on April 2, 2010)	I
10(aw)	-Master Confirmation for Forward Stock Sale Transactions, dated April 2, 2010, between Westar Energy, Inc. and The Bank of New York Mellon (filed as Exhibit 10.1 to the Form 8-K filed on April 2, 2010)	I
10(ax)	-Confirmation of Forward Sale Transaction, dated November 4, 2010, between JPMorgan Chase Bank, National Association, London Branch and Westar Energy, Inc. (filed as Exhibit 10.1 to the Form 8-K filed on November 8, 2010)	I
10(ay)	-Confirmation of Additional Forward Sale Transaction, dated November 5, 2010, between JPMorgan Chase Bank, National Association, London Branch and Westar Energy, Inc. (filed as Exhibit 10.1 to the Form 8-K filed on November 8, 2010)	I
10(az)	-Credit Agreement dated as of February 18, 2011, 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 22, 2011)	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)	-Stipulation and Agreement filed with the Kansas Corporation Commission on October 27, 2008 (filed as Exhibit 99.1 to the Form 8-K filed on October 27, 2008)	I
99(k)	-Civil complaint filed by the United States Department of Justice on February 4, 2009 (filed as Exhibit 99.1 to the Form 8-K filed on February 5, 2009)	I
99(l)	-Consent Decree with the United States Department of Justice and Appendix A thereto filed with the United States District Court for the District of Kansas on or about January 25, 2010 (filed as Exhibits 99.2 and 99.3, respectively, to the Form 8-K filed on January 25, 2010)	I
101.INS	-XBRL Instance Document	#
101.SCH	-XBRL Taxonomy Extension Schema Document	#
101.CAL	-XBRL Taxonomy Extension Calculation Linkbase Document	#
101.DEF	-XBRL Taxonomy Extension Definition Linkbase Document	#
101.LAB	-XBRL Taxonomy Extension Label Linkbase Document	#
101.PRE	-XBRL Taxonomy Extension Presentation Linkbase Document	#

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, 2008				
Allowances deducted from assets for doubtful accounts	$ 5,721	$ 3,580	$ (4,491)	$ 4,810
Year ended December 31, 2009				
Allowances deducted from assets for doubtful accounts	$ 4,810	$ 5,797	$ (5,376)	$ 5,231
Year ended December 31, 2010				
Allowances deducted from assets for doubtful accounts	$ 5,231	$ 8,337	$ (7,839)	$ 5,729

(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 24, 2011	By: /s/ Mark A. Ruelle
	Mark A. Ruelle,
	Executive Vice President and Chief Financial Officer

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SIGNATURES

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

Signature	Title	Date
/S/ WILLIAM B. MOORE (William B. Moore)	Director, President and Chief Executive Officer (Principal Executive Officer)	February 24, 2011
/S/ MARK A. RUELLE (Mark A. Ruelle)	Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	February 24, 2011
/S/ CHARLES Q. CHANDLER IV (Charles Q. Chandler IV)	Chairman of the Board	February 24, 2011
/S/ MOLLIE H. CARTER (Mollie H. Carter)	Director	February 24, 2011
/S/ R. A. EDWARDS III (R. A. Edwards III)	Director	February 24, 2011
/S/ JERRY B. FARLEY (Jerry B. Farley)	Director	February 24, 2011
/S/ B. ANTHONY ISAAC (B. Anthony Isaac)	Director	February 24, 2011
/S/ ARTHUR B. KRAUSE (Arthur B. Krause)	Director	February 24, 2011
/S/ SANDRA A. J. LAWRENCE (Sandra A. J. Lawrence)	Director	February 24, 2011
/S/ MICHAEL F. MORRISSEY (Michael F. Morrissey)	Director	February 24, 2011
/S/ S. CARL SODERSTROM JR. (S. Carl Soderstrom Jr.)	Director	February 24, 2011

Exhibit 12 (a)

WESTAR ENERGY, INC.
Computations of Ratio of Earnings to Fixed Charges and
Computations of Ratio of Earnings to Combined Fixed Charges
and Preferred Dividend Requirements
(Dollars in Thousands)

	Year Ended December 31,				
	2010	2009	2008	2007	2006
Earnings from continuing operations (a)	$293,591	$200,226	$182,139	$232,224	$221,715
Fixed Charges:					
Interest expense (b)	179,272	162,217	126,986	116,973	102,703
Interest on corporate-owned life insurance borrowings	68,926	68,401	58,207	55,164	52,234
Interest applicable to rentals (b)	4,325	22,353	23,227	22,713	21,959
Total Fixed Charges (c)	252,523	252,971	208,420	194,850	176,896
Distributed income of equity investees	—	—	—	—	—
Preferred Dividend Requirements:					
Preferred dividends	970	970	970	970	970
Income tax required	396	404	22	368	330
Total Preferred Dividend Requirements (d)	1,366	1,374	992	1,338	1,300
Total Fixed Charges and Preferred Dividend Requirements	253,889	254,345	209,412	196,188	178,196
Earnings (e)	$546,114	$453,197	$390,559	$427,074	$398,611
Ratio of Earnings to Fixed Charges	2.16	1.79	1.87	2.19	2.25
Ratio of Earnings to Combined Fixed Charges and Preferred Dividend Requirements	2.15	1.78	1.87	2.18	2.24

(a) Earnings from continuing operations consist of income from continuing operations before income taxes, cumulative effects of accounting changes and preferred dividends adjusted for undistributed earnings from equity investees.

(b) As a result of consolidating variable interest entities as discussed in Note 17 of the Notes to Consolidated Financial Statements, “Variable Interest Entities,” amounts previously reported as interest applicable to rentals were reported as interest expense in 2010.

(c) Fixed charges consist of all interest on indebtedness, interest on uncertain tax positions, interest on corporate-owned life insurance policies, amortization of debt discount and expense, and the portion of rental expense that represents an interest factor.

(d) Preferred dividend requirements consist of an amount equal to the pre-tax earnings that would be required to meet dividend requirements on preferred stock.

(e) Earnings are deemed to consist of earnings from continuing operations, fixed charges and distributed income of equity investees.

Exhibit 21

WESTAR ENERGY, INC.
Subsidiaries of the Registrant

Subsidiary	State of Incorporation	Date Incorporated
1) Kansas Gas and Electric Company (a)	Kansas	October 9, 1990

(a) Kansas Gas and Electric Company does business as Westar Energy.

Exhibit 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-165889 on Form S-3, and Registration Statement Nos. 333-93355, 333-70891, 333-13229, 333-151104, 333-149706 and 333-75395 on Form S-8 of our reports dated February 24, 2011 (which reports express an unqualified opinion and includes an explanatory paragraph regarding the adoption of a new accounting standard in 2010), relating to the consolidated financial statements and financial statement schedule of Westar Energy, Inc. and subsidiaries, and the effectiveness of Westar Energy, Inc. and subsidiaries' internal control over financial reporting, appearing in this Annual Report on Form 10-K of Westar Energy, Inc. for the year ended December 31, 2010.

/s/ Deloitte & Touche LLP

Kansas City, Missouri

February 24, 2011

Exhibit 31(a)

WESTAR ENERGY, INC.
CHIEF EXECUTIVE OFFICER
CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, William B. Moore, certify that:

1. I have reviewed this annual report on Form 10-K for the period ended December 31, 2010, of Westar Energy, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2011

By: /s/ William B. Moore
William B. Moore
Director, President and Chief Executive Officer
Westar Energy, Inc.
(Principal Executive Officer)

WESTAR ENERGY, INC.
CHIEF FINANCIAL OFFICER
CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Mark A. Ruelle, certify that:

1. I have reviewed this annual report on Form 10-K for the period ended December 31, 2010, of Westar Energy, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2011

By: /s/ Mark A. Ruelle
Mark A. Ruelle,
Executive Vice President and Chief Financial Officer
Westar Energy, Inc.
(Principal Accounting Officer)

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Westar Energy, Inc. (the Company) on Form 10-K for the year ended December 31, 2010 (the Report), which this certification accompanies, William B. Moore, in my capacity as Director, President and Chief Executive Officer of the Company, and Mark A. Ruelle, in my capacity as Executive Vice President and Chief Financial Officer of the Company, certify that the Report fully complies with the requirements of Section 13(a) or Section 15(d) of the Securities Exchange Act of 1934 and that information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 24, 2011

By: /s/ William B. Moore
William B. Moore
Director, President and Chief Executive Officer

Date: February 24, 2011

By: /s/ Mark A. Ruelle
Mark A. Ruelle,
Executive Vice President and
Chief Financial Officer