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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, 2013

OR

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

For the transition period from __________ to __________

Commission File Number 1-3523

WESTAR ENERGY, INC.

(Exact name of registrant as specified in its charter)

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

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

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

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

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

Securities registered pursuant to section 12(g) of the Act: **None**

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 $4,056,844,230 at June 30, 2013.

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	128,791,042 shares
(Class)	(Outstanding at February 18, 2014)

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 2014 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	BNSF Railway Company
Btu	British thermal units
CAMR	Clean Air Mercury Rule
CCB	Coal combustion byproduct
CO	Carbon monoxide
CO_2	Carbon dioxide
COLI	Corporate-owned life insurance
CSAPR	Cross-State Air Pollution Rule
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
DOE	Department of Energy
DSPP	Direct Stock Purchase Plan
ECRR	Environmental Cost Recovery Rider
EPA	Environmental Protection Agency
EPS	Earnings per share
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings
GAAP	Generally Accepted Accounting Principles
GHG	Greenhouse gas
IM	Integrated Marketplace
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
La Cygne	La Cygne Generating Station
LTISA Plan	Long-Term Incentive and Share Award Plan
MATS	Mercury and Air Toxics Standards
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
PCB	Polychlorinated biphenyl
PM	Particulate matter
PRB	Powder River Basin
RECA	Retail energy cost adjustment

RSU	Restricted share unit
RTO	Regional Transmission Organization
S&P	Standard & Poor's Ratings Services
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
Staff	Staff of the Securities Exchange Commission
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,
- the difficulty of predicting the amount and timing of changes in demand for electricity, including with respect to emerging competing services and technologies,
- 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 existence or introduction of competition into markets in which we operate,
- the impact of frequently changing laws and regulations relating to air and greenhouse gas 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,
- additional regulation due to Nuclear Regulatory Commission (NRC) oversight to ensure the safe operation of Wolf Creek, either related to Wolf Creek's performance, or potentially relating to events or performance at a nuclear plant anywhere in the world,
- uncertainty regarding the establishment of interim or permanent sites for spent nuclear fuel storage and disposal,
- homeland and information and operating systems security considerations,
- 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,
- 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 693,000 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. Significant elements of our strategy include maintaining a flexible and diverse energy supply portfolio. In doing so, we continue to make environmental upgrades to our coal-fired power plants, develop renewable generation, build and upgrade our electrical infrastructure, and develop systems and programs with regard to how our customers use energy.

OPERATIONS

General

As noted above, we supply electric energy at retail to customers in Kansas. We also supply electric energy at wholesale to municipalities and electric cooperatives in Kansas, and have contracts for the sale or purchase of wholesale electricity with other utilities.

Following is the percentage of our revenues by customer classification. Classification of customers as residential, commercial and industrial requires judgment and our classifications may be different from other companies. Assignment of tariffs is not dependent on classification.

	Year Ended December 31,		
	2013	2012	2011
Residential	31%	32%	32%
Commercial	28%	28%	28%
Industrial	16%	16%	16%
Wholesale	15%	14%	16%
Transmission	9%	9%	7%
Other	1%	1%	1%
Total	100%	100%	100%

The percentage of our retail electricity sales by customer class was as follows.

	Year Ended December 31,		
	2013	2012	2011
Residential	34%	34%	35%
Commercial	38%	38%	37%
Industrial	28%	28%	28%
Total	100%	100%	100%

Generation and Firm Capacity Purchases

We have 6,571 megawatts (MW) of accredited generating capacity in service. See "Item 2. Properties" for additional information about our generating units. We own electricity generating facilities or purchase electricity pursuant to long-term contracts from renewable generation facilities with an installed design capacity of 664 MW. Because of the intermittent nature of wind generation, only 14 MW of accredited generating capacity is associated with wind generation facilities. Our capacity and net generation by fuel type are summarized below.

Fuel Type	Capacity(MW)	Percent of Total Capacity	Net Generation (MWh)	Percent of Total Net Generation
Coal	3,424	52%	20,677,415	73%
Nuclear	547	8%	3,369,101	12%
Natural gas/diesel	2,599	39%	1,785,382	6%
Renewable	1	<1%	426,919	2%
Renewable purchase contracts	13	<1%	1,894,308	7%
Total	6,584	100%	28,153,125	100%

In November, 2013 we entered into a renewable energy purchase agreement. Under the agreement, we plan to purchase an additional 200 MW of installed designed capacity to be delivered by the end of 2016.

Our aggregate 2013 peak system net load of 5,186 MW occurred in July 2013. Our net generating capacity, combined with firm capacity purchases and sales and potentially interruptible load, provided a capacity margin of 19% above system peak responsibility at the time of our 2013 peak system net load, which satisfied Southwest Power Pool (SPP) planning requirements.

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
Midwest Energy, Inc.	75	December 2015
Midwest Energy, Inc.	120	May 2017
Midwest Energy, Inc.	35	May 2017
Mid-Kansas Electric Company, LLC	174	January 2019
Kansas Power Pool	59	March 2020
Midwest Energy, Inc.	150	May 2025
Other	13	December 2013 – May 2015
Total	687	

(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 2013, we provided approximately 89 MW to, and received approximately 148 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. The agreement for the city to provide capacity to us is treated as a capital lease.

Fossil Fuel Generation

The effectiveness of a fuel to produce heat is measured in British thermal units (Btu). The higher the Btu content of a fuel, the smaller volume of fuel required to produce a given amount of electricity. We measure the quantity of heat consumed during the generation of electricity in millions of Btu (MMBtu).

Coal

Jeffrey Energy Center (JEC): The three coal-fired units at JEC have an aggregate capacity of 2,155 MW, of which we own or consolidate through a variable interest entity (VIE) a combined 92% share, or 1,983 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 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 the market prices at the time of renegotiation. The most recent price adjustment was effective January 1, 2013.

The BNSF Railway Company (BNSF) and Union Pacific Railroad Company transport coal to JEC under a long-term rail transportation contract. The contract term continues through December 31, 2020, at which time we plan to enter into a new contract. The contract price is subject to price escalation based on certain costs incurred by the railroads.

The average delivered cost of coal consumed at JEC during 2013 was approximately $1.77 per MMBtu, or $29.22 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 consolidate, through a VIE a 50% share, or 709 MW. La Cygne uses primarily PRB coal but one of the two units also uses a small portion of locally-mined coal. The operator of La Cygne, Kansas City Power & Light Company (KCPL), arranges coal purchases and transportation services for La Cygne. Approximately 70%, 40% and 20% of La Cygne's PRB coal requirements are under contract for 2014, 2015 and 2016, respectively. About 80% of those commitments under contract for 2014 are fixed price and all of those commitments under contract are fixed price for 2015 and 2016. As the PRB coal contracts expire, we anticipate that KCPL will negotiate new supply contracts or purchase coal on the spot market.

All of the La Cygne PRB coal is transported under KCPL's rail transportation agreements with BNSF through 2018 and Kansas City Southern Railroad through 2020. During 2013, our share of average delivered cost of coal consumed at La Cygne was approximately $2.06 per MMBtu, or $35.81 per ton.

Lawrence and Tecumseh Energy Centers: Lawrence and Tecumseh Energy Centers have an aggregate generating capacity of 732 MW. We purchase PRB coal for these energy centers under a contract with Arch Coal, Inc., which we expect to provide 100% of the coal requirements through 2014. BNSF transports coal for these energy centers under a contract that expires in December 2020, at which time we plan to enter into a new contract.

During 2013, the average delivered cost of coal consumed in the Lawrence units was approximately $1.78 per MMBtu, or $31.43 per ton. The average delivered cost of coal consumed in the Tecumseh units was approximately $1.74 per MMBtu, or $30.96 per ton.

Natural Gas

We use natural gas as a primary fuel at our Gordon Evans, Murray Gill, 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 2013, we consumed 19.0 million MMBtu of natural gas for a total cost of $83.8 million, or approximately $4.41 per MMBtu. Natural gas accounted for approximately 7% of the total MMBtu of fuel we consumed and approximately 16% of our total fuel expense in 2013. From time to time, we may enter into contracts, including the use of derivatives, in an effort to manage the 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 a natural gas transportation arrangement for Hutchinson Energy Center with Kansas Gas Service. The agreement has historically expired on April 30 of each year and is renegotiated for an additional one year term. 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 transportation agreement with SSCGP. The firm transportation agreement that serves Gordon Evans and Murray Gill Energy Centers extends through April 1, 2020, and the agreement for Lawrence and Tecumseh Energy Centers expires April 1, 2030. The agreement for the State Line facility extends through July 30, 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 transportation agreement with ONEOK Gas Transportation, LLC.

Diesel

We use 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 and satisfy emergency requirements. We do not use significant amounts of diesel in our operations.

Nuclear Generation

General

Wolf Creek is a 1,164 MW nuclear power plant located near Burlington, Kansas. KGE owns a 47% interest in Wolf Creek, or 547 MW. Wolf Creek's operating license, issued by the NRC, is effective until 2045. Wolf Creek Nuclear Operating Corporation, an operating company owned by each of the plant's owners in proportion to their ownership share of the plant, operates the plant. The plant's owners pay operating costs proportionate to their respective ownership share.

Fuel Supply

Wolf Creek has on hand or under contract all of the uranium and conversion services needed to operate through September 2016 and approximately 70% of the uranium and conversion services needed after that date through March 2021. The owners also have under contract all of the uranium enrichment and fabrication services required to operate Wolf Creek through March 2027 and September 2025, respectively. All such agreements have been entered into in the ordinary course of business.

Operations and Regulation

Plant performance, including extended or unscheduled shutdowns of Wolf Creek, could cause us to purchase replacement power, rely more heavily on our other generating units and/or reduce amounts of power available for us to sell in the wholesale market. Plant performance also affects the degree of regulatory oversight and related costs. In early 2014, Wolf Creek will undergo a planned maintenance outage. Because the outage is not part of a refueling outage, the related costs will be expensed as incurred. We expect our share of the outage to be approximately $9.0 million.

Wolf Creek normally operates on an 18-month planned refueling and maintenance outage schedule. As authorized by our regulators, incremental maintenance costs of planned refueling and maintenance outages are deferred and amortized ratably over the period between planned outages. During outages at the plant, we meet our electric demand primarily with our other generating units and by purchasing power.

The NRC evaluates, monitors and rates various inspection findings and performance indicators for Wolf Creek based on 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.

See Note 13 of the Notes to Consolidated Financial Statements, "Commitments and Contingencies," for additional information regarding our nuclear operations.

Wind Generation

As discussed under "Environmental Matters—Renewable Energy Standard" below, Kansas law requires that our energy supply resources consist of a certain amount of renewable sources. For us, wind has been the primary source of renewable energy. As of December 31, 2013, we owned approximately 149 MW of designed installed wind capacity and had under contract the purchase of wind energy produced from approximately 715 MW of designed installed wind capability. Of the 715 MW under contract, 200 MW are associated with an agreement pursuant to which a generation provider is scheduled to deliver power beginning in 2016.

Other Fuel Matters

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

	2013	2012	2011
Per MMBtu:			
Nuclear	$ 0.75	$ 0.70	$ 0.68
Coal	1.82	1.86	1.74
Natural gas	4.41	3.20	4.81
Diesel	22.89	23.12	19.33
All generating stations	1.91	1.84	1.92
Per MWh Generation:			
Nuclear	$ 7.86	$ 7.28	$ 7.15
Coal	20.26	20.59	19.30
Natural gas/diesel	46.38	33.29	52.65
All generating stations	20.45	19.65	20.60

Our wind production has no associated fuel costs and is, therefore, not included in the table above.

Purchased Power

In addition to generating electricity, we also purchase power. Factors that cause us to purchase power include contractual arrangements, planned and unscheduled outages at our generating plants, favorable wholesale energy prices compared to our 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 2013, purchased power comprised approximately 18% of our total fuel and purchased power expense. Our weighted average cost of purchased power per Megawatt hour (MWh) was $33.63 in 2013, $26.41 in 2012 and $34.27 in 2011.

Transmission

Regional Transmission Organization

The Federal Energy Regulatory Commission (FERC) requires owners of regulated transmission assets to allow third parties nondiscriminatory access to their transmission systems. We are a member of the SPP RTO and transferred the functional control of our transmission system, including the approval of transmission service, to the SPP. 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 the amounts it collects from transmission users less an amount it retains to cover administrative expenses.

Developing Forward Market in SPP

The SPP is scheduled to launch an Integrated Marketplace (IM) in March 2014. The SPP IM will be similar to other organized power markets currently operating in other RTOs. The SPP IM will change how we currently sell the output from our generation facilities and buy power to meet the needs of our customers. The SPP will have the authority to start and stop generating units participating in the market and will select the lowest cost resource mix to meet the needs of the various SPP customers while ensuring reliable operations of the transmission system. As with other organized markets, there will be additional market related products, revenues, and charges. Westar recently submitted the necessary regulatory filings seeking to recognize the associated revenues and charges in the prices we charge our customers, similar to our current retail energy cost adjustment tariff.

Regulation and Our Prices

Kansas law gives the Kansas Corporation Commission (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 electricity sales, including prices, 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 costs. For portions of our cost of service, regulators allow us to adjust our prices periodically through the application of formulae that track changes in our costs, which reduce the time between making expenditures or investments and reflecting them in the prices we charge customers. However, for the remaining portions of our cost of service, we must file a general rate review, which lengthens the period of time between when we make and recover expenditures and a return on our investments. See Note 3 of the Notes to Consolidated Financial Statements, "Rate Matters and Regulation," for information regarding our rate proceedings with the KCC and FERC.

Environmental Matters

General

We are subject to various federal, state and local environmental laws and regulations. Environmental laws and regulations affecting our operations are overlapping, complex, subject to changes, have become more stringent over time and are expensive to implement. Such laws and regulations relate primarily to air quality, water quality, 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 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 the cost of 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 currently permitted to recover certain of these costs through the environmental cost recovery rider (ECRR), which, in comparison to a general rate review, reduces the amount of time it takes to begin collecting in retail prices the costs associated with capital expenditures for qualifying environmental improvements. However, there can be no assurance that the costs to comply with existing or future environmental laws and regulations will not have a material effect on our operations or 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 federal and state regulations that impose, among other things, limitations on emissions generated from our operations, including sulfur dioxide (SO_2), particulate matter (PM), nitrogen oxides (NOx), carbon monoxide (CO), mercury and acid gases.

Emissions from our generating facilities, including PM, 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) and the Environmental Protection Agency (EPA), we are required to install, operate and maintain controls to reduce emissions found to cause or contribute to regional haze. In addition, our power plants that burn fossil fuels emit carbon dioxide, which is also regulated under the Clean Air Act and for which the EPA is presently developing regulations.

Sulfur Dioxide and Nitrogen Oxide

Through the combustion of fossil fuels at our generating facilities, we emit SO_2 and NOx. Federal and state laws and regulations, including those noted above, and permits issued to us limit the amount of these substances we can emit. If we exceed these limits we could be subject to fines and penalties. In order to meet SO_2 and NOx 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 Acid Rain Program. Under this program, each unit must have enough allowances to cover its SO_2 emissions for that year. In 2013, we had adequate SO_2 allowances to meet planned generation and we expect to have enough to cover emissions under this program in 2014.

Cross-State Air Pollution Rule

In 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR) requiring 28 states, including Kansas, Missouri and Oklahoma, to further reduce power plant emissions of SO_2 and NOx beginning January 2012, with further reductions required beginning January 2014. In August 2012, the U.S. Court of Appeals for the District of Columbia Circuit vacated CSAPR and remanded the rule to the EPA to promulgate a replacement. This decision is now under review by the U.S. Supreme Court. We cannot at this time predict the outcome of the U.S. Supreme Court's review; however, based on our current and planned environmental controls, if the regulations were to be reinstated or replaced, either in part or in whole, we do not believe the impact on our operations and consolidated financial results would be material.

National Ambient Air Quality Standards

Under the federal Clean Air Act, the EPA sets National Ambient Air Quality Standards (NAAQS) for certain emissions considered harmful to public health and the environment, including two classes of PM, NOx (a precursor to ozone), CO and SO_2, which result from fossil fuel combustion. Areas meeting the NAAQS are designated attainment areas while those that do not meet the NAAQS are considered nonattainment areas. 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. KDHE, our state environmental regulatory agency, proposed to designate portions of the Kansas City area nonattainment for the eight-hour ozone standard. The EPA has not acted on KDHE's proposed designation of the Kansas City area and it is uncertain when, or if, such a designation might occur. The Wichita area also exceeded the eight-hour ozone standard and could be designated nonattainment in the future potentially impacting our operations.

In September 2011, the President instructed the EPA not to implement its more stringent 2008 Ozone Standard since a new NAAQS for ozone was due to be proposed in 2013 and finalized in 2014. We are waiting on this new standard and cannot at this time predict the impact it may have on our operations, but it could be material.

In December 2012, the EPA strengthened an existing NAAQS for one class of PM. By the end of 2014, the EPA anticipates making final attainment/nonattainment designations under this rule and expects to issue a final implementation rule. We are currently evaluating the rule, however, we cannot at this time predict the impact it may have on our operations or consolidated financial results, but it could be material.

In 2010 the EPA strengthened the NAAQS for both NOx and SO_2. We continue to communicate with our regulators regarding these standards and are currently evaluating what impact this could have on our operations and consolidated financial results. 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.

Mercury and Other Air Emissions

The operation of power plants results in emissions of mercury, acid gases and other air toxics. In 2012, the EPA's Mercury and Air Toxics Standards (MATS) for power plants became effective, replacing the prior federal Clean Air Mercury Rule (CAMR) and requiring significant reductions in mercury, acid gases and other emissions. We expect to be compliant with the new standards by April 2016 as approved by KDHE. We continue to evaluate the new standards and believe that our related investment will be approximately $17.0 million.

Greenhouse Gases

Byproducts of burning coal and other fossil fuels include carbon dioxide (CO_2) and other gases referred to as greenhouse gases (GHGs), which are believed by many to contribute to climate change. The EPA has proposed using the federal Clean 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 with the goal of reducing GHG emissions.

In January 2014, the EPA re-proposed a New Source Performance Standard (NSPS) that would limit CO_2 emissions for new coal and natural gas fueled generating units. The re-proposal would limit CO_2 emissions to 1,000 lbs per MWh generated for larger natural gas units and 1,100 lbs per MWh generated for smaller natural gas units and coal units. Final regulations are expected later in 2014. The EPA was also directed to issue proposed standards addressing CO_2 emissions for modified, reconstructed and existing power plants by June 2014, issue final rules by June 2015, and require that states submit their implementation plans to the EPA no later than June 2016. We cannot at this time determine the impact of such proposals on our operations and consolidated financial results, but we believe the costs to comply could be material.

Under regulations known as the Tailoring Rule, the EPA regulates GHG emissions from certain stationary sources. The regulations are being implemented pursuant to two federal Clean Air Act programs which impose recordkeeping and monitoring requirements and also mandate the implementation of best available control technology (BACT) for projects that cause a significant increase in GHG emissions (defined to be more than 75,000 tons or more per year or 100,000 tons or more per year, depending on various factors). 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 regulations on our future operations and consolidated financial results, but we believe the cost of compliance with the regulations could be material.

Water

We discharge some of the water used in our operations. This water may contain substances deemed to be pollutants. Revised rules governing such discharges from coal-fired power plants are expected to be issued by the EPA in 2014. Although we cannot at this time determine the timing or impact of compliance with any new regulations, more stringent regulations could have a material impact on our operations and consolidated financial results.

In 2011, the EPA issued a proposed rule that would increase the requirements for cooling intake structures at power plants over concerns about impacts to aquatic life. We are currently evaluating the proposed rule as well as recent nationally-issued information requests from the EPA. The EPA is required to finalize the rule by April 2014; however, because the rule has yet to be finalized, we cannot predict the impact it may have on our operations 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 coal combustion byproducts (CCBs), including fly ash, gypsum and bottom ash. We recycle some of our ash production, principally by selling to the aggregate industry. In 2010, the EPA proposed a rule to regulate CCBs at the federal level, which we believe might impair our ability to recycle ash or require additional CCB handling, processing and storage equipment, or both. The EPA has agreed, subject to court approval, to issue a final rule in 2014. While we cannot at this time estimate the impact and costs associated with future regulations of CCBs, we believe the impact on our operations and consolidated financial results could be material.

Renewable Energy Standard

Kansas law mandates that we maintain a minimum amount of renewable energy sources. Through 2015, net renewable generation capability must be 10% of the average peak retail 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. With our existing wind generation facilities, supply contracts and renewable energy credits, we are able to satisfy the net renewable generation requirement through 2015. With our agreement to purchase an additional 200 MW of installed design capcaity from a wind generation facility beginning in late 2016, we expect to meet the increased requirements through 2020. If we are unable to meet future requirements, our operations and consolidated financial results could be adversely impacted.

Environmental Costs

As discussed above, environmental laws and regulations affecting our operations are evolving and becoming more stringent. As a result, we are making and will continue to make significant capital and operating expenditures 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 existing regulations, new regulations, legislation and the manner in which we operate our plants. The degree to which we will need to reduce certain 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.

We are not allowed to use the ECRR to collect approximately $610.0 million of the projected capital investment associated with environmental upgrades at La Cygne. In November 2013, the KCC issued an order allowing us to adjust our prices to include the additional investment in the La Cygne environmental upgrades and to reflect cost reductions elsewhere. The new prices are expected to increase our annual retail revenues by approximately $30.7 million. To change our prices to collect increased operating and maintenance costs, we must file a general rate review with the KCC.

Our estimated capital expenditures associated with environmental improvements for 2014-2016 appear in the following table. We prepare these estimates for planning purposes and revise them from time to time.

Year	Total
	(In Thousands)
2014	$ 237,000
2015	112,000
2016	21,900
Total	$ 370,900

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 expenses and may reduce the net production, reliability and availability of the plants. Furthermore, enhancements to our power plants, even if they result in greater efficiency, can trigger a new source review, which could require additional control equipment. In order to change our prices to recognize increased operating and maintenance costs, we must file a general rate review with the KCC.

EPA Consent Decree

As part of a 2010 settlement of a lawsuit filed by the Department of Justice on behalf of the EPA, we are installing selective catalytic reduction (SCR) equipment on one of three JEC coal units by the end of 2014, which we estimate will cost approximately $230.0 million. We are installing less expensive NOx reduction equipment on the other two units to satisfy other terms of the settlement. We plan to complete these projects in 2014 and recover the costs to install these systems through our ECRR, but such recovery remains subject to the approval of our regulators.

Safety and Health Regulation

The safety and health of our employees is vital to our business. We are subject to a number of federal and state laws and regulations, including the Occupational Safety and Health Act of 1970. We believe we have appropriate measures in place to ensure the safety and health of our employees and to monitor compliance with such laws and regulations.

Information Technology

Safeguarding information technology networks and systems is important to our business. There are risks associated with the unauthorized access, theft or accidental release of electronic data, which may result in the misappropriation or corruption of our information or cause operational disruptions. We believe these risks are getting increasingly larger and more sophisticated. We believe that we have taken appropriate measures to secure our information infrastructure from attacks or breaches and from accidental release of information, but notwithstanding such measures, the increasing sophistication of potential attacks may result in remaining vulnerabilities. See Item 1A, "Risk Factors," for additional information.

SEASONALITY

Our electricity sales and revenues are seasonal, with the third quarter typically accounting for the greatest of each. Our electricity sales are impacted by weather conditions, the economy of our service territory and other factors affecting customers' demand for electricity.

EMPLOYEES

As of February 18, 2014, we had 2,302 employees. In 2013, we negotiated a contract extension with Locals 304 and 1523 of the International Brotherhood of Electrical Workers that extends through June 30, 2017. The contract covers 1,256 employees as of February 18, 2014.

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 on our Internet website at www.westarenergy.com or through 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.

EXECUTIVE OFFICERS OF THE COMPANY

Name	Age	Present Office	Other Offices or Positions Held During the Past Five Years
Mark A. Ruelle	52	Director, President and Chief Executive Officer (since August 2011)	**Westar Energy, Inc.** Director, President and Chief Financial Officer (May 2011 to July 2011) Executive Vice President and Chief Financial Officer (January 2003 to April 2011)
Douglas R. Sterbenz	50	Executive Vice President and Chief Operating Officer (since July 2007)	
Greg A. Greenwood	48	Senior Vice President, Strategy (since August 2011)	**Westar Energy, Inc.** Vice President, Major Construction Projects (December 2009 to July 2011) Vice President, Generation Construction (August 2006 to December 2009)
Anthony D. Somma	50	Senior Vice President, Chief Financial Officer and Treasurer (since August 2011)	**Westar Energy, Inc.** Vice President, Treasurer (February 2009 to July 2011) Treasurer (August 2006 to February 2009)
Larry D. Irick	57	Vice President, General Counsel and Corporate Secretary (since February 2003)	
Kevin L. Kongs	51	Vice President, Controller (since November 2013)	**Westar Energy, Inc.** Assistant Controller (October 2006 to November 2013)

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, our 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 which 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, persistent or severe drought conditions could result in limited power production. High water conditions can also impair planned deliveries of fuel to our plants.

Our prices are subject to regulatory review and may not prove adequate to recover our costs and provide a fair return.

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 such 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 through the application of formulae that track changes in certain of our costs, our prices generally remain fixed until changed following a rate review. Further, the adjustments 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 take positions adverse to us. In addition, 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. Further, 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 implementing price changes to reflect changes in our costs, could have a material affect on our consolidated financial results.

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

We are subject to extensive federal, state and local environmental statutes, rules and regulations relating to air quality, 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 have tended to become more restrictive, requires us to commit significant capital and operating resources toward permitting, emission fees, environmental monitoring, installation and operation of air and water quality control equipment, and purchases of air emission allowances and/or offsets.

Costs of compliance with environmental laws and regulations or fines or penalties resulting from non-compliance, if not recovered in our prices, could adversely affect our operations and/or 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 or any possible fines or penalties with certainty, or the degree to which such costs might be recovered in our prices, due to our inability to predict the requirements and timing of implementation of environmental rules or regulations. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Executive Summary—Current Trends—Environmental Regulation—Air Emissions" for additional information.

In addition, we combust large amounts of fossil fuels as we produce electricity. This results in significant emissions of CO_2 and other GHGs through the operation of our power plants. Federal legislation has been in the past and is expected in the future to be introduced in Congress to regulate the emission of GHGs and numerous states and regions have adopted programs to stabilize or reduce GHG emissions.

The EPA regulates GHGs under the Clean Air Act. Under regulations finalized in 2010, the EPA is regulating GHG emissions from certain stationary sources, such as power plants. Under the current regulations, any source that emits at least 75,000 tons per year of GHGs is 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 permits upon renewal. Additionally, Prevention of Significant Deterioration Program permits for new major sources of GHG emissions and GHG sources that undergo major modifications are required to implement 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. Additionally, in January 2014, the EPA re-proposed an NSPS that would limit CO_2 emissions for new coal and natural gas fueled electric generating units. This proposal is expected to become a final rule in 2014. We are currently evaluating the proposal and believe it could impact our future generation plans if it becomes a final rule. In addition, the EPA is also expected to propose in June 2014, a GHG NSPS for existing units that could have a material impact on our operations.

Further, in the course of operating our coal generation plants, we produce CCBs, including fly ash, gypsum and bottom ash, which we must handle, recycle, process or dispose of. We recycle some of our ash production, principally by selling to the aggregate industry. In 2010, the EPA proposed a rule to regulate CCBs, which we believe might impair our ability to recycle ash or require additional CCB handling, processing and storage equipment, or both. The EPA has agreed, subject to court approval, to issue a final rule in 2014. While we cannot at this time estimate the impact and costs associated with future regulations of CCBs, we believe the impact on our operations and consolidated financial results could be material.

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 were found to be out of compliance with the mandatory reliability standards, we could be subject to sanctions, including substantial monetary penalties, which we might not be able to recover in the prices we charge our customers. This could have a material affect on our consolidated financial results.

Adverse economic conditions could adversely impact our operations and 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; and
- 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.

In the opposite, unexpectedly strong economic conditions can result in increased costs and shortages. Any of the aforementioned events, and others we may not be able to identify, could have an adverse impact on our consolidated financial results.

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 off-site 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.

If an incident did occur at Wolf Creek, it could have a material 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 anywhere in the world 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. Such events could also result in a shutdown of Wolf Creek.

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 market. If we were unable to recover these costs in the prices we charge customers, such events would likely have an adverse impact 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, environmental and other regulatory requirements, economic conditions, social pressures and the responsiveness of customers' electricity demand to conservation measures and prices. Both actual future demand and our ability to satisfy such demand depend 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 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 2014 through 2016 are approximately $2.1 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 and health and safety 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.

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. Further, capital market conditions can cause fluctuations in the values of assets set aside for employee benefit obligations and the Wolf Creek nuclear decommissioning trust (NDT) and may increase our funding requirements related to these obligations.

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 effects 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.

Further, 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 for meeting our obligations. Additionally, inflation and changes in interest rates affect the value of future liabilities. In general, when interest rates decline, the value of future liabilities increase. While the KCC allows 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. 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 and cash flows could be adversely affected.

Security breaches, criminal activity, terrorist attacks and other disruptions to our information technology infrastructure could directly or indirectly interfere with our operations, could expose us or our customers or employees to a risk of loss, and could expose us to liability, regulatory penalties, reputational damage and other harm to our business.

We rely upon information technology networks and systems to process, transmit and store electronic information, and to manage or support a variety of business processes and activities, including the generation, transmission and distribution of electricity, supply chain functions, and the invoicing and collection of payments from our customers. We also use information technology systems to record, process and summarize financial information and results of operations for internal reporting purposes and to comply with financial reporting, legal and tax requirements. Our technology networks and systems collect and store sensitive data including system operating information, proprietary business information belonging to us and third parties, and personal information belonging to our customers and employees.

Our information technology networks and infrastructure may be vulnerable to damage, disruptions or shutdowns due to attacks by hackers or breaches due to employee error or malfeasance, or other disruptions during software or hardware upgrades, telecommunication failures or natural disasters or other catastrophic events. The occurrence of any of these events could impact the reliability of our generation, transmission and distribution systems; could expose us, our customers or our employees to a risk of loss or misuse of information; and could result in legal claims or proceedings, liability or regulatory penalties against us, damage our reputation or otherwise harm our business. We cannot accurately assess the probability that a security breach may occur, despite the measures that we take to prevent such a breach, and we are unable to quantify the potential impact of such an event. We can provide no assurance that we will identify and remedy all security or system vulnerabilities or that unauthorized access or error will be identified and remedied.

Additionally, we cannot predict the impact that any future information technology or terrorist attack may have on the energy industry in general. Our facilities could be direct targets or indirect casualties of such attacks. The effects of such attacks could include disruption to our generation, transmission and distribution systems or to the electrical grid in general, and could increase the cost of insurance coverage or result in a decline in the U.S. economy.

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 require the use of expensive and complicated equipment, much of which is aged, and all of which requires significant ongoing maintenance. Our power plants and equipment are subject to extended or unplanned outages because of equipment failure, weather, transmission system disruption, operator error, contractor or subcontractor failure and other factors beyond our control. In such events, we must either produce replacement power from our other plants, which may be less efficient or more expensive to operate, purchase power from others at unpredictable and potentially higher costs in order to meet our sales obligations, or suffer outages. 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.

Our regulated business model may be threatened by technological advancements that could adversely affect our financial condition and results of operations.

Significant technological advancements are taking place in the electric industry, including advancements related to self-generation and distributed energy technologies such as fuel cells, micro turbines, wind turbines and solar cells. Adoption of these technologies may increase because of advancements or government subsidies reducing the cost of generating electricity through these technologies to a level that is competitive with our current methods of generating electricity. There is also a perception that generating electricity through these technologies is more environmentally friendly than generating electricity with fossil-fuels. Increased adoption of these technologies could reduce electricity demand and the pool of customers from whom fixed costs are recovered, resulting in under recovery of our fixed costs. Increased self-generation and the related use of net energy metering, which allows self-generating customers to receive bill credits for surplus power, could put upward price pressure on our remaining customers because self-generating customers do not currently pay a share of the costs necessary to operate our transmission and distribution system. If we were unable to adjust our prices to reflect reduced electricity demand and increased self-generation and net energy metering, our financial condition and results of operations could be adversely affected.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Name	Location	Unit No.	Year Installed	Principal Fuel	Unit Capacity (MW) By Owner Westar Energy	KGE	Total Company
Central Plains Wind Farm	Wichita County, Kansas	(a)	2009	Wind	—	—	—
Emporia Energy Center:	Emporia, Kansas						
Combustion Turbines		1	2008	Gas	45	—	45
		2	2008	Gas	45	—	45
		3	2008	Gas	44	—	44
		4	2008	Gas	46	—	46
		5	2008	Gas	157	—	157
		6	2009	Gas	153	—	153
		7	2009	Gas	156	—	156
Flat Ridge Wind Farm	Barber County, Kansas	(a)	2009	Wind	1	—	1
Gordon Evans Energy Center:	Colwich, Kansas						
Steam Turbines		1	1961	Gas	—	152	152
		2	1967	Gas	—	372	372
Combustion Turbines		1	2000	Gas	68	—	68
		2	2000	Gas	66	—	66
		3	2001	Gas	148	—	148
Hutchinson Energy Center:	Hutchinson, Kansas						
Steam Turbine		4	1965	Gas	171	—	171
Combustion Turbines		1	1974	Gas	56	—	56
		2	1974	Gas	52	—	52
		3	1974	Gas	57	—	57
		4	1975	Diesel	71	—	71
Jeffrey Energy Center (92%):	St. Marys, Kansas						
Steam Turbines		1 (b)	1978	Coal	517	144	661
		2 (b)	1980	Coal	515	143	658
		3 (b)	1983	Coal	520	144	664
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	49	—	49
		4	1960	Coal	107	—	107
		5	1971	Coal	374	—	374
Murray Gill Energy Center:	Wichita, Kansas						
Steam Turbines		1	1952	Gas	—	37	37
		2	1954	Gas	—	48	48
		3	1956	Gas	—	93	93
		4	1959	Gas	—	90	90
Spring Creek Energy Center:	Edmond, Oklahoma						
Combustion Turbines		1 (d)	2001	Gas	68	—	68
		2 (d)	2001	Gas	68	—	68
		3 (d)	2001	Gas	67	—	67
		4 (d)	2001	Gas	68	—	68
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	72	—	72
		8	1962	Coal	130	—	130
Wolf Creek Generating Station (47%):	Burlington, Kansas						
Nuclear		1 (b)	1985	Uranium	—	547	547
Total					4,092	2,479	6,571

(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 (50%) and Wolf Creek (47%). We jointly own and consolidate as a VIE 92% of JEC. 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. 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 24,000 miles of overhead distribution lines and approximately 4,700 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 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" and "Legal Proceedings," respectively, which are incorporated herein by reference.

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable.

PART II

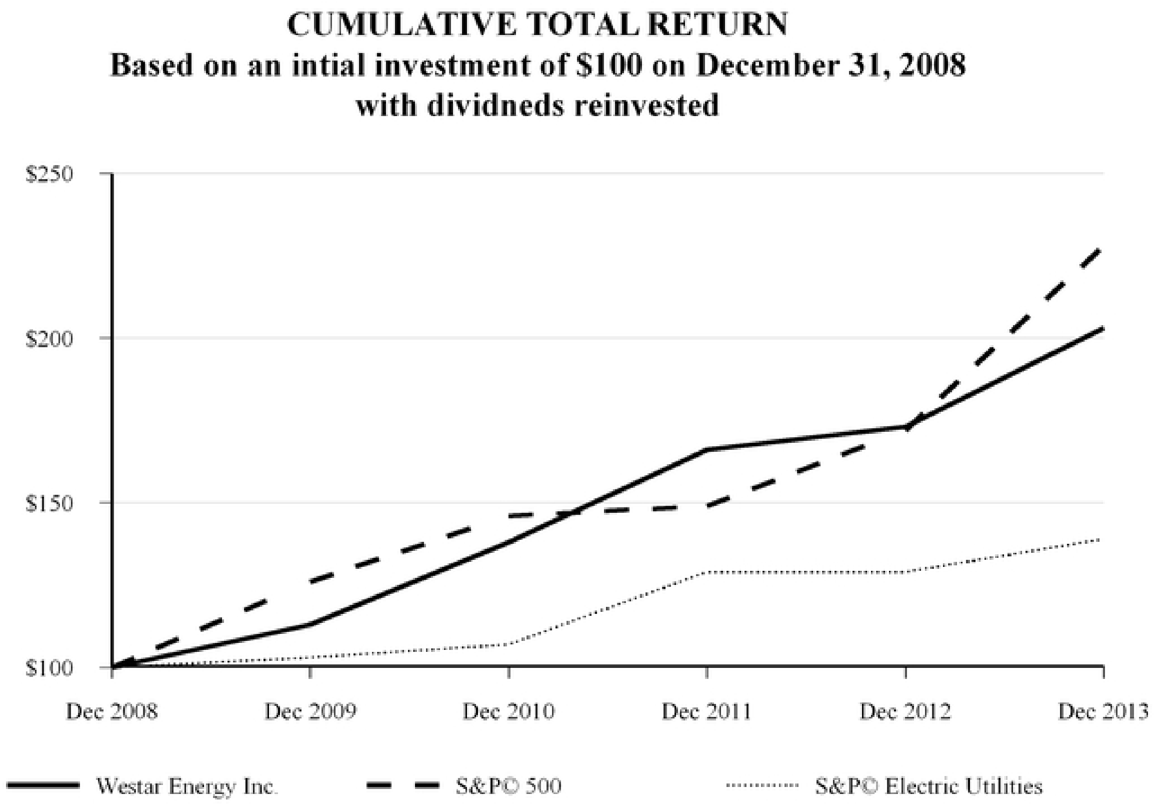
ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

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 18, 2014, Westar Energy had 19,436 common shareholders of record. For information regarding quarterly common stock price ranges for 2013 and 2012, see Note 19 of the Notes to Consolidated Financial Statements, "Quarterly Results (Unaudited)."

STOCK PERFORMANCE GRAPH

The following graph compares the performance of Westar Energy's common stock during the period that began on December 31, 2008, and ended on December 31, 2013, to the performance of 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 2008	Dec 2009	Dec 2010	Dec 2011	Dec 2012	Dec 2013
Westar Energy Inc.	$100	$113	$138	$166	$173	$203
S&P© 500	$100	$126	$146	$149	$172	$228
S&P© Electric Utilities	$100	$103	$107	$129	$129	$139

DIVIDENDS

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

Quarterly dividends on common 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. In 2013, Westar Energy's board of directors declared four quarterly dividends of $0.34 per share, reflecting an annual dividend of $1.36 per share, compared to four quarterly dividends of $0.33 per share in 2012, reflecting an annual dividend of $1.32 per share. On February 26, 2014, Westar Energy's board of directors declared a quarterly dividend of $0.35 per share payable to shareholders on April 1, 2014. The indicated annual dividend rate is $1.40 per share.

ITEM 6. SELECTED FINANCIAL DATA

	Year Ended December 31,				
	2013	2012	2011	2010	2009
	(In Thousands)				
Income Statement Data:					
Total revenues	$ 2,370,654	$ 2,261,470	$ 2,170,991	$ 2,056,171	$ 1,858,231
Net income (a)	300,863	282,462	236,180	208,624	141,330
Net income attributable to common stock	292,520	273,530	229,269	202,926	174,105

	As of December 31,				
	2013	2012	2011	2010	2009
	(In Thousands)				
Balance Sheet Data:					
Total assets	$ 9,597,111	$ 9,265,231	$ 8,682,851	$ 8,079,638	$ 7,525,483
Long-term obligations (b)	3,495,292	3,124,831	2,818,030	2,808,560	2,610,315

	Year Ended December 31,				
	2013	2012	2011	2010	2009
Common Stock Data:					
Basic earnings per share available for common stock (c)	$ 2.29	$ 2.15	$ 1.95	$ 1.81	$ 1.58
Diluted earnings per share available for common stock	2.27	2.15	1.93	1.80	1.58
Dividends declared per share	1.36	1.32	1.28	1.24	1.20
Book value per share	23.88	22.89	22.03	21.25	20.59
Average equivalent common shares outstanding (in thousands) (d) (e)	127,463	126,712	116,891	111,629	109,648

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(a) The 2009 amount represents income from continuing operations.
(b) Includes long-term debt, net, current maturities of long-term debt, capital leases and, for 2010 through 2013, long-term debt of VIEs, net and current maturities of long-term debt of VIEs. See Note 17 of the Notes to Consolidated Financial Statements, "Variable Interest Entities," for additional information regarding VIEs.
(c) We recorded basic EPS available for common stock from continuing operations of $1.28 in 2009 using 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.
(d) In 2010, Westar Energy issued and sold approximately 3.1 million shares of common stock realizing proceeds of $54.7 million.
(e) In 2011, Westar Energy issued and sold approximately 13.6 million shares of common stock realizing proceeds of $294.9 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. See "Forward Looking Statements" above for additional information.

EXECUTIVE SUMMARY

Description of Business

We are the largest electric utility in Kansas. We produce, transmit and sell electricity at retail to approximately 693,000 customers in Kansas under the regulation of the KCC. We also supply electric energy at wholesale to municipalities and electric cooperatives in Kansas under the regulation of FERC. We have contracts for the sale or purchase of wholesale electricity with other utilities.

Earnings Per Share

Following is a summary of our net income and basic EPS for the years ended December 31, 2013 and 2012.

	Year Ended December 31,		
	2013	2012	Change
	(Dollars In Thousands, Except Per Share Amounts)		
Net income attributable to common stock	$ 292,520	$ 273,530	$ 18,990
Earnings per common share, basic	2.29	2.15	0.14

Net income attributed to common stock and basic EPS for the year ended December 31, 2013, increased due primarily to higher prices and lower selling, general and administrative expenses. Lower electricity sales as a result of cooler weather and reduced demand for electricity served to partially offset the aforementioned increases. See the discussion under "—Operating Results" below for additional information.

Key Factors Affecting Our Performance

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

- weather conditions;
- the economy;
- customer conservation efforts;
- the performance, operation and maintenance of our electric generating facilities and network;
- conditions in the fuel, wholesale electricity and energy markets;
- rate and other regulations and costs of addressing public policy initiatives including environmental regulations;
- 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. Significant elements of our strategy include maintaining a flexible and diverse energy supply portfolio. In doing so, we continue to make environmental upgrades to our coal-fired power plants, develop renewable generation, build and upgrade our electrical infrastructure, and develop systems and programs with regard to how our customers use energy.

Current Trends

Environmental Regulation

Environmental laws and regulations affecting our operations, which relate primarily to air quality, water quality, 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 and costly over time. We have incurred and will continue to incur significant capital and other expenditures, and may potentially need to limit the use of some of our power plants, to comply with existing and new environmental laws and regulations. While certain of these costs are recoverable through the ECRR and ultimately we expect all such costs to be reflected in the prices we are allowed to charge, we cannot assure that all such costs will be recovered or that they will be recovered in a timely manner. See Note 13 of the Notes to Condensed Consolidated Financial Statements, "Commitments and Contingencies," for additional information regarding environmental laws and regulations.

Air Emissions

The operation of power plants results in emissions of mercury, acid gases and other air toxics. In 2012, the EPA's MATS for power plants became effective, replacing the prior federal CAMR and requiring significant reductions in mercury, acid gases and other emissions. We expect to be compliant with the new standards by April 2016 as approved by KDHE. We continue to evaluate the new standards and believe that our related investment will be approximately $17.0 million.

Greenhouse Gases

In January 2014, the EPA re-proposed a NSPS that would limit CO_2 emissions for new coal and natural gas fueled generating units. The re-proposal would limit CO_2 emissions to 1,000 lbs per MWh generated for larger natural gas units and 1,100 lbs per MWh generated for smaller natural gas units and coal units. Final regulations are expected later in 2014. The EPA was also directed to issue proposed standards addressing CO_2 emissions for modified, reconstructed and existing power plants by June 2014, issue final rules by June 2015, and require that states submit their implementation plans to the EPA no later than June 2016. We cannot at this time determine the impact of such proposals on our operations and consolidated financial results, but we believe the costs to comply could be material.

Under regulations known as the Tailoring Rule, the EPA regulates GHG emissions from certain stationary sources. The regulations are being implemented pursuant to two federal Clean Air Act programs which impose recordkeeping and monitoring requirements and also mandate the implementation of BACT for projects that cause a significant increase in GHG emissions (defined to be more than 75,000 tons or more per year or 100,000 tons or more per year, depending on various factors). 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 regulations on our future operations and consolidated financial results, but we believe the costs to comply with the regulations could be material.

Regulation of Coal Combustion Byproducts

In the course of operating our coal generation plants, we produce CCBs, including fly ash, gypsum and bottom ash. We recycle some of our ash production, principally by selling to the aggregate industry. In 2010, the EPA proposed a rule to regulate CCBs, which we believe might impair our ability to recycle ash or require additional CCB handling, processing and storage equipment, or both. The EPA has agreed, subject to court approval, to issue a final rule in 2014. While we cannot at this time estimate the impact and costs associated with future regulations of CCBs, we believe the impact on our operations and consolidated financial results could be material.

National Ambient Air Quality Standards

Under the federal Clean Air Act, the EPA sets NAAQS for certain emissions considered harmful to public health and the environment, including two classes of PM, NOx (a precursor to ozone), CO and SO_2, which result from fossil fuel combustion. Areas meeting the NAAQS are designated attainment areas while those that do not meet the NAAQS are considered nonattainment areas. Each state must develop a plan to bring nonattainment areas into compliance with the NAAQS. NAAQS must be reviewed by EPA at five-year intervals. KDHE proposed to designate portions of the Kansas City area nonattainment for the eight-hour ozone standard. The EPA has not acted on KDHE's proposed designation of the Kansas City area and it is uncertain when, or if, such a designation might occur. The Wichita area also exceeded the eight-hour ozone standard and could be designated nonattainment in the future potentially impacting our operations.

In September 2011, the President instructed the EPA not to implement its more stringent 2008 Ozone Standard since a new NAAQS for ozone was due to be proposed in 2013 and finalized in 2014. We are waiting on this new standard and cannot at this time predict the impact it may have on our operations, but it could be material.

In December 2012, the EPA strengthened an existing NAAQS for one class of PM. By the end of 2014, the EPA anticipates making final attainment/nonattainment designations under this rule and expects to issue a final implementation rule. We are currently evaluating the rule, however, we cannot at this time predict the impact it may have on our operations or consolidated financial results, but it could be material.

In 2010, the EPA strengthened the NAAQS for both NOx and SO_2. We continue to communicate with our regulators regarding these standards and are currently evaluating what impact this could have on our operations and consolidated financial results. 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.

Water

We discharge some of the water used in our operations. This water may contain substances deemed to be pollutants. Revised rules governing such discharges from coal-fired power plants are expected to be issued by the EPA in 2014. Although we cannot at this time determine the timing or impact of compliance with any new regulations, more stringent regulations could have a material impact on our operations and consolidated financial results.

In 2011, the EPA issued a proposed rule that would increase the requirements for cooling water intake structures at power plants over concerns about impacts to aquatic life. We are currently evaluating the proposed rule as well as recent nationally-issued information requests from the EPA. The EPA is required to finalize the rule by April 2014; however, because the rule has yet to be finalized, we cannot predict the impact it may have on our operations or consolidated financial results, but it could be material.

Renewable Energy Standard

Kansas law mandates that we maintain a minimum amount of renewable energy sources. Through 2015, net renewable generation capacity must be 10% of the average peak retail 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. With our existing wind generation facilities, supply contracts and renewable energy credits, we are able to satisfy the net renewable generation requirement through 2015. With our agreement to purchase an additional 200 MW of installed design capacity from a wind generation facility beginning in late 2016, we expect to meet the increased requirements through 2020. If we are unable to meet future requirements, our operations and consolidated financial results could be adversely impacted.

Regulation of Nuclear Generating Station

Additional regulation of Wolf Creek resulting from NRC oversight of the plant's performance or from changing regulations generally, including those that could potentially result from natural disasters or any event that might occur at any nuclear power plant anywhere in the world, may result in increased operating and capital expenditures. We cannot estimate the cost associated with such increases, but they could be material to our operations and consolidated financial results.

We expect future increases in operating costs due to increased NRC oversight and efforts to comply with new industry-wide regulations adopted by the NRC in 2012. Future extended or unscheduled shutdowns 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 in the wholesale market.

Allowance for Funds Used During Construction

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 other income (for equity funds) and interest expense (for borrowed funds) for the amount of AFUDC capitalized as construction cost on the accompanying consolidated statements of income as follows:

	Year Ended December 31,		
	2013	2012	2011
	(In Thousands)		
Borrowed funds	$ 11,706	$ 10,399	$ 5,589
Equity funds	14,143	11,706	5,550
Total	$ 25,849	$ 22,105	$ 11,139
Average AFUDC Rates	4.8%	5.0%	3.6%

We expect AFUDC for both 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 continue to 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 historical standards. We cannot predict to what extent these conditions will continue. See Note 9 of the Notes to Consolidated Financial Statements, "Long-Term Debt" for additional information regarding the issuance of long-term debt.

Outstanding Shares of Common Stock

We expect the number of outstanding shares of Westar Energy common stock to increase through 2015 as we issue additional shares previously priced through forward sales agreements 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 share issuances.

Customer Growth and Usage

Residential customer additions have slowed and electricity demand is stable to slightly declining due principally to the effects of the economic downturn and energy efficiency measures. Absent an economic recovery to conditions similar to those preceding the downturn, we believe such customer additions will continue to be significantly lower than historical levels. In addition, with the numerous energy efficiency policy initiatives promulgated through federal, state and local governments, as well as industry, we believe customers will continue to adopt more energy efficiency and conservation measures which will suppress the rate of demand for electricity.

2014 Outlook

In 2014, we expect to maintain our current business strategy and regulatory approach. Subject to regulatory approvals, we anticipate annualized price increases of approximately $50.0 million from formulae that track changes in certain of our costs, as well as a $30.7 million general price increase authorized by the KCC in November 2013. Assuming normal weather in line with the historical average, we expect 2014 retail electricity sales to be between about 0.5% to 1.0% higher than weather-normalized 2013 sales.

In addition, we anticipate increased operating and maintenance expenses, including maintenance costs for our power plants, and higher selling, general and administrative expenses. SPP transmission expense and property taxes are increasing at a much higher rate than inflation and are offset with higher revenues pursuant to our regulatory mechanisms. To help fund our capital spending as provided under "—Future Cash Requirements" below, we plan to utilize short-term borrowings and we expect to issue common stock to settle forward sale transactions.

In March 2014, the SPP is expected to launch an IM similar to other organized power markets currently operating in other RTOs. As a result, we expect an increase in revenues and a corresponding increase in fuel and purchased power expense. Further, additional products may result in increased derivative activity, currently presented in other assets and liabilities, for which we will receive regulatory treatment.

CRITICAL ACCOUNTING ESTIMATES

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

Regulatory Accounting

We currently apply accounting standards 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, 2013, we had recorded regulatory assets currently subject to recovery in future prices of approximately $755.4 million and regulatory liabilities of $329.6 million, as discussed in greater detail in Note 3 of the Notes to Consolidated Financial Statements, "Rate Matters and Regulation."

Pension and Post-retirement Benefit Plans Actuarial Assumptions

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

In accounting for our retirement plans and 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 result primarily in changes to regulatory assets, regulatory liabilities or the amount of related pension and post-retirement benefit 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)	Annual Change in Projected Pension Costs (a)
		(Dollars In Thousands)	
Discount rate	0.5% decrease	$ 70,159	$ 6,721
	0.5% increase	(63,319)	(6,234)
Salary scale	0.5% decrease	(17,359)	(3,392)
	0.5% increase	17,686	3,491
Rate of return on plan assets	0.5% decrease	—	3,359
	0.5% increase	—	(3,359)

(a) Increases or decreases due to changes in actuarial assumptions result primarily 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 and a 1% change in the annual medical trend on our post-retirement benefit plans.

Actuarial Assumption	Change in Assumption	Change in Projected Benefit Obligation (a)	Annual Change in Projected Post-retirement Costs (a)
		(Dollars In Thousands)	
Discount rate	0.5% decrease	$ 8,174	$ 436
	0.5% increase	(7,702)	(446)
Rate of return on plan assets	0.5% decrease	—	521
	0.5% increase	—	(519)
Annual medical trend	1.0% decrease	(1,804)	(261)
	1.0% increase	1,996	292

(a) Increases or decreases due to changes in actuarial assumptions result primarily 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 recorded estimated unbilled revenue of $60.1 million as of December 31, 2013 and $62.5 million as of December 31, 2012.

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 the extent capital losses, operating losses, or tax credits will be carried forward to future periods. 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, 2013 and 2012, we have recorded AROs of $160.7 million and $152.6 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 collect in our prices the costs to dispose of plant assets that do not represent legal retirement obligations. As of December 31, 2013 and 2012, we had $114.1 million and $129.0 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 Notes 13 and 15 of the Notes to Consolidated Financial Statements, "Commitments and Contingencies" and "Legal Proceedings," for additional 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. Margins realized from these sales serve to offset retail prices through either the RECA or at the time of our next general rate case.

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 transactions unrelated to the production of our generating assets and fees we earn for services that we provide for third parties.

Electric utility revenues are impacted by things such as rate regulation, fuel costs, technology, customer behavior, 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 and commercial customers and, to a lesser extent, industrial 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.

2013 Compared to 2012

Below we discuss our operating results for the year ended December 31, 2013, compared to the results for the year ended December 31, 2012. Significant changes in results of operations shown in the table immediately below are further explained in the descriptions that follow.

	Year Ended December 31,			
	2013	2012	Change	% Change
	(Dollars In Thousands, Except Per Share Amounts)			
REVENUES:				
Residential	$ 728,852	$ 714,562	$ 14,290	2.0
Commercial	667,106	640,654	26,452	4.1
Industrial	374,825	368,909	5,916	1.6
Other retail	8,939	(5,845)	14,784	252.9
Total Retail Revenues	1,779,722	1,718,280	61,442	3.6
Wholesale	348,239	316,353	31,886	10.1
Transmission (a)	210,281	193,797	16,484	8.5
Other	32,412	33,040	(628)	(1.9)
Total Revenues	2,370,654	2,261,470	109,184	4.8
OPERATING EXPENSES:				
Fuel and purchased power	634,797	589,990	44,807	7.6
SPP network transmission costs	178,604	166,547	12,057	7.2
Operating and maintenance	359,060	342,055	17,005	5.0
Depreciation and amortization	272,593	270,464	2,129	0.8
Selling, general and administrative	224,133	226,012	(1,879)	(0.8)
Taxes other than income tax	122,282	104,269	18,013	17.3
Total Operating Expenses	1,791,469	1,699,337	92,132	5.4
INCOME FROM OPERATIONS	579,185	562,133	17,052	3.0
OTHER INCOME (EXPENSE):				
Investment earnings	10,056	7,411	2,645	35.7
Other income	35,609	35,378	231	0.7
Other expense	(18,099)	(19,987)	1,888	9.4
Total Other Income	27,566	22,802	4,764	20.9
Interest expense	182,167	176,337	5,830	3.3
INCOME BEFORE INCOME TAXES	424,584	408,598	15,986	3.9
Income tax expense	123,721	126,136	(2,415)	(1.9)
NET INCOME	300,863	282,462	18,401	6.5
Less: Net income attributable to noncontrolling interests	8,343	7,316	1,027	14.0
NET INCOME ATTRIBUTABLE TO WESTAR ENERGY, INC.	292,520	275,146	17,374	6.3
Preferred dividends	—	1,616	(1,616)	(100.0)
NET INCOME ATTRIBUTABLE TO COMMON STOCK	$ 292,520	$ 273,530	$ 18,990	6.9
BASIC EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING ATTRIBUTABLE TO WESTAR ENERGY	$ 2.29	$ 2.15	$ 0.14	6.5
DILUTED EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING ATTRIBUTABLE TO WESTAR ENERGY	$ 2.27	$ 2.15	$ 0.12	5.6

(a) Reflects revenue from an SPP network transmission tariff corresponding to our SPP network transmission costs. These costs, less administration fees of $39.1 million and $27.2 million, were returned to us as revenue in 2013 and 2012, respectively.

Rate Case Agreement

In November 2013, the KCC issued an order allowing us to adjust our prices to include the additional investment in the La Cygne environmental upgrades, as discussed below, and to reflect cost reductions elsewhere. The new prices are expected to increase our annual retail revenues by approximately $30.7 million.

In April 2012, the KCC issued an order authorizing higher revenues to recover higher expenses primarily for increased tree trimming to enhance reliability and increased pension costs resulting from the consequences of the 2008 financial crisis and subsequent low interest rate environment in accordance with the regulatory mechanism in place to account for such pension costs. As a result of this order, we expect selling, general and administrative expense to increase $32.1 million and the cost of operating and maintaining our distribution system to increase $10.9 million on an annualized basis. In addition, we revised our depreciation rates to reflect changes in the estimated useful lives of some of our assets. The change in estimate will decrease annual depreciation expense by $43.6 million. However, decreased depreciation expense as a result of lower depreciation rates will be offset by additional depreciation related to additions to property, plant and equipment. Because the aforementioned changes were implemented shortly after the KCC issued its order, our 2012 consolidated financial results do not reflect the full annual impact of the changes.

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. In addition, SPP network transmission costs fluctuate due primarily to investments by us and other members of the SPP for upgrades to the transmission grid within the SPP RTO. As with fuel and purchased power costs, changes in SPP network transmission costs are mostly reflected in the prices we charge customers with minimal impact on net income. For these reasons, we believe gross margin is useful for understanding and analyzing changes in our operating performance from one period to the next. We calculate gross margin as total revenues, including transmission revenues, less the sum of fuel and purchased power costs and amounts billed by the SPP for network transmission costs. Accordingly, gross margin reflects transmission revenues and costs on a net basis. The following table summarizes our gross margin for the years ended December 31, 2013 and 2012.

	Year Ended December 31,			
	2013	2012	Change	% Change
	(Dollars In Thousands)			
Revenues	$ 2,370,654	$ 2,261,470	$ 109,184	4.8
Less: Fuel and purchased power expense	634,797	589,990	44,807	7.6
SPP network transmission costs	178,604	166,547	12,057	7.2
Gross Margin	$ 1,557,253	$ 1,504,933	$ 52,320	3.5

The following table reflects changes in electricity sales for the years ended December 31, 2013 and 2012. 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,			
	2013	2012	Change	% Change
	(Thousands of MWh)			
ELECTRICITY SALES:				
Residential	6,523	6,684	(161)	(2.4)
Commercial	7,480	7,581	(101)	(1.3)
Industrial	5,407	5,588	(181)	(3.2)
Other retail	86	85	1	1.2
Total Retail	19,496	19,938	(442)	(2.2)
Wholesale	8,593	7,719	874	11.3
Total	28,089	27,657	432	1.6

Gross margin increased due primarily to higher retail revenues that were the result of higher prices offset partially by lower retail electricity sales. The lower retail electricity sales were attributable principally to cooler summer weather, which particularly impacted residential and commercial electricity sales. As measured by cooling degree days, 2013 was 23% cooler than the prior year. Contributing also to the decrease in retail sales was the reduced demand, primarily from several large industrial customers.

Income from operations is the most directly comparable measure to our presentation of 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, 2013 and 2012.

	Year Ended December 31,			
	2013	2012	Change	% Change
	(Dollars In Thousands)			
Gross margin	$ 1,557,253	$ 1,504,933	$ 52,320	3.5
Less: Operating and maintenance expense	359,060	342,055	17,005	5.0
Depreciation and amortization expense	272,593	270,464	2,129	0.8
Selling, general and administrative expense	224,133	226,012	(1,879)	(0.8)
Taxes other than income tax	122,282	104,269	18,013	17.3
Income from operations	$ 579,185	$ 562,133	$ 17,052	3.0

Operating Expenses and Other Income and Expense Items

	Year Ended December 31,			
	2013	2012	Change	% Change
	(Dollars in Thousands)			
Operating and maintenance expense	$ 359,060	$ 342,055	$ 17,005	5.0

Operating and maintenance expense increased due principally to:

- higher costs for tree trimming, pursuant to authorized rate recovery, and other distribution reliability activities of $11.8 million; and
- higher costs at Wolf Creek of $5.0 million, due principally to higher amortization of refueling outage costs and recognition of costs incurred during an unscheduled maintenance outage in 2013.

	Year Ended December 31,			
	2013	2012	Change	% Change
	(Dollars in Thousands)			
Depreciation and amortization expense	$ 272,593	$ 270,464	$ 2,129	0.8

Depreciation and amortization expense increased due to additional depreciation expense resulting primarily from increased plant additions at our power plants, including air quality controls, and the addition of transmission facilities. Partially offsetting this increase was a result of our having reduced depreciation rates in mid 2012 to reflect changes in the estimated useful lives of some of our assets.

	Year Ended December 31,			
	2013	2012	Change	% Change
	(Dollars in Thousands)			
Selling, general and administrative expense	$ 224,133	$ 226,012	$ (1,879)	(0.8)

Selling, general and administrative expense decreased due primarily to:

- lower post-retirement and other employee benefit costs of $8.6 million due principally to restructuring insurance contracts; and,
- lower labor cost of $2.3 million, which in part reflects expenses recorded in 2012 related to sustainable cost reduction activities; however,
- partially offsetting these decreases were higher pension costs of $12.3 million, most of which were offset with higher revenues. These increased pension cost were principally a consequence of the 2008 financial market downturn and the subsequent low interest rate environment.

	Year Ended December 31,			
	2013	2012	Change	% Change
	(Dollars in Thousands)			
Taxes other than income tax	$ 122,282	$ 104,269	$ 18,013	17.3

Taxes other than income tax increased due primarily to an $18.2 million increase in property taxes, which are offset in retail revenues.

	Year Ended December 31,			
	2013	2012	Change	% Change
	(Dollars in Thousands)			
Investment earnings	$ 10,056	$ 7,411	$ 2,645	35.7

Investment earnings increased due principally to:

- $1.2 million increase in earnings from our investment in Prairie Wind Transmission, LLC; and,
- $1.4 million of additional gains on investments in a trust to fund retirement benefits.

	Year Ended December 31,			
	2013	2012	Change	% Change
	(Dollars in Thousands)			
Interest expense	$ 182,167	$ 176,337	$ 5,830	3.3

Interest expense increased due to our recording $10.5 million in interest principally related to additional debt issued to fund capital investment. Partially offsetting this increase was a $2.2 million decrease of interest expense on long-term debt of VIEs and a $1.3 million decrease for capitalized interest.

2012 Compared to 2011

Below we discuss our operating results for the year ended December 31, 2012, compared to the results for the year ended December 31, 2011. Significant changes in results of operations shown in the table immediately below are further explained in the descriptions that follow.

	Year Ended December 31,			
	2012	2011	Change	% Change
	(Dollars In Thousands, Except Per Share Amounts)			
REVENUES:				
Residential	$ 714,562	$ 693,388	$ 21,174	3.1
Commercial	640,654	604,626	36,028	6.0
Industrial	368,909	347,881	21,028	6.0
Other retail	(5,845)	(8,964)	3,119	34.8
Total Retail Revenues	1,718,280	1,636,931	81,349	5.0
Wholesale	316,353	346,948	(30,595)	(8.8)
Transmission (a)	193,797	154,569	39,228	25.4
Other	33,040	32,543	497	1.5
Total Revenues	2,261,470	2,170,991	90,479	4.2
OPERATING EXPENSES:				
Fuel and purchased power	589,990	630,793	(40,803)	(6.5)
SPP network transmission costs	166,547	132,164	34,383	26.0
Operating and maintenance	342,055	332,989	9,066	2.7
Depreciation and amortization	270,464	285,322	(14,858)	(5.2)
Selling, general and administrative	226,012	184,695	41,317	22.4
Taxes other than income tax	104,269	92,599	11,670	12.6
Total Operating Expenses	1,699,337	1,658,562	40,775	2.5
INCOME FROM OPERATIONS	562,133	512,429	49,704	9.7
OTHER INCOME (EXPENSE):				
Investment earnings	7,411	9,301	(1,890)	(20.3)
Other income	35,378	8,652	26,726	308.9
Other expense	(19,987)	(18,398)	(1,589)	(8.6)
Total Other Income (Expense)	22,802	(445)	23,247	(b)
Interest expense	176,337	172,460	3,877	2.2
INCOME BEFORE INCOME TAXES	408,598	339,524	69,074	20.3
Income tax expense	126,136	103,344	22,792	22.1
NET INCOME	282,462	236,180	46,282	19.6
Less: Net income attributable to noncontrolling interests	7,316	5,941	1,375	23.1
NET INCOME ATTRIBUTABLE TO WESTAR ENERGY. INC.	275,146	230,239	44,907	19.5
Preferred dividends	1,616	970	646	66.6
NET INCOME ATTRIBUTABLE TO COMMON STOCK	$ 273,530	$ 229,269	$ 44,261	19.3
BASIC EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING ATTRIBUTABLE TO WESTAR ENERGY	$ 2.15	$ 1.95	$ 0.20	10.3
DILUTED EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING ATTRIBUTABLE TO WESTAR ENERGY	$ 2.15	$ 1.93	$ 0.22	11.4

(a) Reflects revenue from an SPP network transmission tariff corresponding to our SPP network transmission costs. These costs, less administration fees of $27.2 million and $18.6 million, respectively, were returned to us as revenue.
(b) Change greater than 1,000%.

Gross Margin

The following table summarizes our gross margin for the years ended December 31, 2012 and 2011.

	Year Ended December 31,			
	2012	2011	Change	% Change
	(Dollars In Thousands)			
Revenues	$ 2,261,470	$ 2,170,991	$ 90,479	4.2
Less: Fuel and purchased power expense	589,990	630,793	(40,803)	(6.5)
SPP network transmission costs	166,547	132,164	34,383	26.0
Gross Margin	$ 1,504,933	$ 1,408,034	$ 96,899	6.9

The following table reflects changes in electricity sales for the years ended December 31, 2012 and 2011. 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,			
	2012	2011	Change	% Change
	(Thousands of MWh)			
ELECTRICITY SALES:				
Residential	6,684	6,986	(302)	(4.3)
Commercial	7,581	7,573	8	0.1
Industrial	5,588	5,589	(1)	(a)
Other retail	85	88	(3)	(3.4)
Total Retail	19,938	20,236	(298)	(1.5)
Wholesale	7,719	8,215	(496)	(6.0)
Total	27,657	28,451	(794)	(2.8)

(a) Change less than 0.1%

Gross margin increased due primarily to higher retail revenues that were the result of higher prices offset partially by lower retail electricity sales. The lower retail electricity sales were attributable principally to moderate weather, which particularly impacted residential electricity sales. In 2012, cooling degree days were similar to 2011; however, cooling degree days during the third quarter of 2012 were 9% lower than the same period of 2011.

The following table reconciles income from operations with gross margin for the years ended December 31, 2012 and 2011.

	Year Ended December 31,			
	2012	2011	Change	% Change
	(Dollars In Thousands)			
Gross margin	$ 1,504,933	$ 1,408,034	$ 96,899	6.9
Less: Operating and maintenance expense	342,055	332,989	9,066	2.7
Depreciation and amortization expense	270,464	285,322	(14,858)	(5.2)
Selling, general and administrative expense	226,012	184,695	41,317	22.4
Taxes other than income tax	104,269	92,599	11,670	12.6
Income from operations	$ 562,133	$ 512,429	$ 49,704	9.7

Operating Expenses and Other Income and Expense Items

	Year Ended December 31,			
	2012	2011	Change	% Change
	(Dollars in Thousands)			
Operating and maintenance expense	$ 342,055	$ 332,989	$ 9,066	2.7

Operating and maintenance expense increased due principally to:

- higher costs for tree trimming, pursuant to authorized rate recovery, and other electrical system reliability activities of $5.9 million; and
- higher costs at Wolf Creek of $4.6 million, which were the result primarily of maintenance costs incurred during an unscheduled outage.

	Year Ended December 31,			
	2012	2011	Change	% Change
	(Dollars in Thousands)			
Depreciation and amortization expense	$ 270,464	$ 285,322	$ (14,858)	(5.2)

Depreciation and amortization expense decreased as a result of our having reduced depreciation rates to reflect changes in the estimated useful lives of some of our assets. Partially offsetting this decrease was additional depreciation expense associated primarily with additions at our power plants, including air quality controls, and the addition of transmission facilities.

	Year Ended December 31,			
	2012	2011	Change	% Change
	(Dollars in Thousands)			
Selling, general and administrative expense	$ 226,012	$ 184,695	$ 41,317	22.4

Selling, general and administrative expense increased due primarily to:

- our having reversed $22.0 million of previously accrued liabilities in 2011 as a result of settling litigation;
- higher pension and other employee benefit costs of $20.2 million pursuant to authorized rate recovery;
- our having recorded $4.5 million of expense as a result of sustainable cost reduction activities; and
- a $2.1 million increase in the amortization of previously deferred amounts associated with various energy efficiency programs, which we recover in retail revenues; however,
- partially offsetting these increases was a $9.4 million decrease in legal fees that was the result principally of arbitration and litigation that occurred in 2011.

	Year Ended December 31,			
	2012	2011	Change	% Change
	(Dollars in Thousands)			
Taxes other than income tax	$ 104,269	$ 92,599	$ 11,670	12.6

Taxes other than income tax increased due primarily to a $9.2 million increase in property taxes, which is offset in retail revenues.

	Year Ended December 31,			
	2012	2011	Change	% Change
	(Dollars in Thousands)			
Investment earnings	$ 7,411	$ 9,301	$ (1,890)	(20.3)

Investment earnings decreased due principally to:

- our having recorded a $7.2 million gain on the sale of a non-utility investment in 2011; however,
- partially offsetting this item was our having recorded $4.5 million of additional gains on investments in a trust to fund retirement benefits and a $1.7 million increase in earnings from our investment in Prairie Wind Transmission, LLC.

	Year Ended December 31,			
	2012	2011	Change	% Change
	(Dollars in Thousands)			
Other income	$ 35,378	$ 8,652	$ 26,726	308.9

Other income increased due principally to:

- our having recorded an additional $17.4 million in COLI (corporate-owned life insurance) benefits;
- a $6.2 million increase in equity AFUDC, which reflects more construction activity; and
- our having recorded an additional $3.1 million related to the sale of oil inventory.

	Year Ended December 31,			
	2012	2011	Change	% Change
	(Dollars in Thousands)			
Income tax expense	$ 126,136	$ 103,344	$ 22,792	22.1

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

Financial Condition

A number of factors affected amounts recorded on our balance sheet as of December 31, 2013, compared to December 31, 2012.

	As of December 31,			
	2013	2012	Change	% Change
	(Dollars in Thousands)			
Fuel inventory and supplies	$ 239,511	$ 249,016	$ (9,505)	(3.8)

Fuel inventory and supplies decreased due principally to a $16.7 million decrease in coal inventory, due to a price reduction in the cost of coal and reduced transportation costs. This decrease was partially offset by a $6.8 million increase in materials and supplies as a result of higher inventory replacement costs as well as materials purchased for spring 2014 outages.

	As of December 31,			
	2013	2012	Change	% Change
	(Dollars in Thousands)			
Property, plant and equipment, net	$ 7,551,916	$ 7,013,765	$ 538,151	7.7

Property, plant and equipment, net of accumulated depreciation, increased due primarily to additions at our power plants, including air quality controls, and the addition of transmission facilities.

	As of December 31,			
	2013	2012	Change	% Change
	(Dollars in Thousands)			
Property, plant and equipment of variable interest entities, net	$ 296,626	$ 321,975	$ (25,349)	(7.9)

Property, plant and equipment of variable interest entities, net of accumulated depreciation, decreased due to deconsolidating a rail car lease as discussed in Note 17 of the Notes to Consolidated Financial Statements, "Variable Interest Entities," and normal depreciation of these assets.

	As of December 31,			
	2013	2012	Change	% Change
	(Dollars in Thousands)			
Regulatory assets	$ 755,414	$ 1,002,672	$ (247,258)	(24.7)
Regulatory liabilities	329,556	323,175	6,381	2.0
Net regulatory assets	$ 425,858	$ 679,497	$ (253,639)	(37.3)

Total regulatory assets decreased due primarily to the following reasons:

- a $265.1 million decrease in deferred employee benefit costs, due primarily to decreased pension and post-retirement benefit obligations as a result of increases in the discount rates used to calculate our and Wolf Creek's benefits obligations;
- a $9.6 million decrease in amounts previously deferred for storm costs;
- a $5.3 million decrease in amounts due from customers for future income taxes; and
- a $4.4 million decrease in amounts deferred for energy efficiency costs; however,
- partially offsetting decreases were a $17.9 million, $14.9 million and $12.7 million increase in amounts deferred for fuel expense, for the Wolf Creek outage and for property taxes, respectively.

Regulatory liabilities increased due primarily to a $24.9 million increase in the fair value of the NDT and an $8.3 million increase in other post-retirement costs. Partially offsetting this increase was a $14.8 million decrease in amounts collected but not yet spent to dispose of plant assets.

	As of December 31,			
	2013	2012	Change	% Change
	(Dollars in Thousands)			
Short-term debt	$ 134,600	$ 339,200	$ (204,600)	(60.3)

Short-term debt decreased due to decreases in issuances of commercial paper. Proceeds from issuances of long-term debt were used to repay short-term debt, which had been used primarily to purchase capital equipment, to redeem bonds and for working capital and general corporate purposes.

	As of December 31,			
	2013	2012	Change	% Change
	(Dollars in Thousands)			
Current maturities of long-term debt	$ 250,000	$ —	$ 250,000	
Long-term debt, net	2,968,958	2,819,271	149,687	5.3
Total long-term debt	$ 3,218,958	$ 2,819,271	$ 399,687	14.2

Total long-term debt increased due to the issuance of $500.0 million principal amount of first mortgage bonds. This increase was partially offset by our redemption of two pollution control bond issues with an aggregate principal amount of

$100.0 million. Both the issuance and redemptions are further discussed in Note 9 of the Notes to Consolidated Financial Statements, “Long-Term Debt.”

	As of December 31,			
	2013	2012	Change	% Change
	(Dollars in Thousands)			
Current maturities of long-term debt of variable interest entities	$ 27,479	$ 25,942	$ 1,537	5.9
Long-term debt of variable interest entities	194,802	222,743	(27,941)	(12.5)
Total long-term debt of variable interest entities	$ 222,281	$ 248,685	$ (26,404)	(10.6)

Total long-term debt of variable interest entities decreased due principally to the VIEs that hold the JEC and La Cygne leasehold interests having made principal payments totaling $25.4 million.

	As of December 31,			
	2013	2012	Change	% Change
	(Dollars in Thousands)			
Deferred income tax liabilities	$ 1,361,418	$ 1,197,837	$ 163,581	13.7

Long-term deferred income tax liabilities increased due primarily to the use of bonus and accelerated depreciation methods during the year.

	As of December 31,			
	2013	2012	Change	% Change
	(Dollars in Thousands)			
Accrued employee benefits	$ 331,558	$ 564,870	$ (233,312)	(41.3)

Accrued employee benefits decreased due primarily to lower pension and post-retirement benefit obligations as a result of increases in the discount rates used to calculate our and Wolf Creek's benefits obligations.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Available sources of funds to operate our business include internally generated cash, short-term borrowings under Westar Energy's commercial paper program and 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 short-term borrowings. To meet the cash requirements for our capital investments, we expect to use internally generated cash, short-term borrowings, and proceeds from the issuance of debt and equity securities in the capital markets. When such balances are of sufficient size and it makes economic sense to do so, we also use proceeds from the issuance of long-term debt and equity securities to repay short-term borrowings, which are principally related to investments in capital equipment and the redemption of bonds and for working capital and general corporate purposes. For additional information on our future cash requirements, see "—Future Cash Requirements" below.

In 2014, we expect to continue our significant capital spending program and plan 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, 2013 and 2012, our capital structure, excluding short-term debt, was as follows:

	As of December 31,	
	2013	2012
Common equity	47%	49%
Noncontrolling interests	<1%	<1%
Long-term debt, including VIEs	53%	51%

Short-Term Borrowings

In 2011, Westar Energy entered into a commercial paper program pursuant to which it may issue commercial paper up to a maximum aggregate amount outstanding at any one time of $1.0 billion. This program is supported by Westar Energy's revolving credit facilities. Maturities of commercial paper issuances may not exceed 365 days from the date of issuance and proceeds from such issuances will be used to temporarily fund capital expenditures, to repay borrowings under Westar Energy's revolving credit facilities, for working capital and/or for other general corporate purposes. As of February 18, 2014, Westar Energy had issued $177.8 million of commercial paper.

Westar Energy has two revolving credit facilities in the amounts of $730.0 million and $270.0 million. In July 2013, Westar Energy extended the term of the $730.0 million facility to September 2017, and in February 2014, Westar Energy extended the term of the $270.0 million credit facility to February 2017, provided that $20.0 million of this facility will terminate in February 2016. As long as there is no default under the facility, the $730.0 million facility may be extended an additional year and the aggregate amount of borrowings under the $730.0 million and $270.0 million facilities may be increased to $1.0 billion and $400.0 million, respectively, subject to lender participation. All borrowings under the facilities are secured by KGE first mortgage bonds. Total combined borrowings under the revolving credit facilities and the commercial paper program may not exceed $1.0 billion at any given time. As of February 18, 2014, no amounts were borrowed and $18.5 million of letters of credit had been issued under the $730.0 million facility. No amounts were borrowed and no letters of credit were issued under the $270.0 million facility as of the same date.

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 of 65% or less at all times. At December 31, 2013, our ratio was 53%. See Note 8 of the Notes to Consolidated Financial Statements, "Short-Term Debt," for additional information regarding our short-term borrowings.

Long-Term Debt Financing

We have $250.0 million in outstanding aggregate principal amount of first mortgage bonds that are due July 1, 2014. We expect to issue additional long-term debt to redeem those bonds before the maturity date thereof.

In August 2013, Westar Energy issued $250.0 million principal amount of first mortgage bonds bearing stated interest of 4.625% and maturing in September 2043.

In June 2013, KGE redeemed two pollution control bond series with an aggregate principal amount of $100.0 million and stated interest rates of 5.60% and 6.00%.

In March 2013, Westar Energy issued $250.0 million principal amount of first mortgage bonds bearing stated interest of 4.10% and maturing in April 2043. Proceeds from these issuances were used to repay short-term debt, which had been used primarily to purchase capital equipment, to redeem bonds and for working capital and general corporate purposes.

As of December 31, 2013, we had $121.9 million of variable rate, tax-exempt bonds. While the interest rates for these bonds have been extremely low, we continue to monitor the credit markets and evaluate our options with respect to these bonds.

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, 2013, approximately $505.3 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, 2013, approximately $1.1 billion 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 credit agreements. We calculate these ratios in accordance with the agreements and they are used to determine compliance with our various debt covenants. We were in compliance with these covenants as of December 31, 2013.

Impact of Credit Ratings on Debt Financing

Moody's Investors Service (Moody's), Standard & Poor's Ratings Services (S&P) and Fitch Ratings (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, more favorable credit ratings increase borrowing opportunities and reduce the cost of borrowing. Under Westar Energy's revolving credit facilities and commercial paper program, our cost of borrowings is determined in part by credit ratings. However, Westar Energy's ability to borrow under the credit facilities and commercial paper program are 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.

In January 2014, Moody's upgraded its ratings for Westar Energy and KGE first mortgage bonds to A2 from A3. In February 2013, S&P revised its criteria for rating utility first mortgage bonds and, as a result, upgraded its ratings for Westar Energy and KGE first mortgage bonds/senior secured debt to A- from BBB+. Additionally, in April 2013, S&P affirmed its ratings for Westar Energy and KGE and raised its outlook to positive from stable.

As of February 18, 2014, our ratings with the agencies are as shown in the table below.

	Westar Energy First Mortgage Bond Rating	KGE First Mortgage Bond Rating	Westar Energy Commercial Paper	Rating Outlook
Moody’s	A2	A2	P-2	Stable
S&P	A-	A-	A-2	Positive
Fitch	A-	A-	F2	Stable

Common and Preferred Stock

Common Stock

Westar Energy's Restated Articles of Incorporation, as amended, provide for 275.0 million authorized shares of common stock. As of December 31, 2013, Westar Energy had 128.3 million shares issued and outstanding.

In September 2013, Westar Energy entered into two forward sale agreements with two banks. Under the terms of the agreements, the banks, as forward sellers, borrowed 8.0 million shares of Westar Energy's common stock from third parties and sold them to a group of underwriters for $31.15 per share. Pursuant to over-allotment options granted to the underwriters, the underwriters purchased in October 2013, an additional 0.9 million shares from the banks as forward sellers, increasing the total number of shares under the forward sale agreements to approximately 8.9 million. The underwriters received a commission equal to 3.5% of the sales price of all shares sold under the agreements. Westar Energy must settle such transactions within 24 months.

In March 2013, Westar Energy entered into a new, three-year sales agency financing agreement and master forward sale confirmation with a bank, similar to the sales agency financing agreement and master forward sale confirmation entered into in April 2010. The maximum amount that Westar Energy may offer and sell under the March 2013 master agreements is the lesser of an aggregate of $500.0 million or approximately 25.0 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. In addition, under the terms of the March 2013 sales agency financing agreement and master forward sale confirmation, 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 agent. The agent receives a commission equal to 1% of the sales price of all shares sold under the agreements. Westar Energy must settle the forward sale transactions within 18 months of the date each transaction is entered.

In April 2010, Westar Energy entered into a three-year Sales Agency Financing Agreement and forward sale agreement with a bank that was terminated in March 2013. The maximum amount that Westar Energy could offer and sell under the agreements was 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 could offer and sell shares of its common stock from time to time through the broker dealer subsidiary, as agent. The broker dealer received 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 could 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 was required to settle the forward sale transactions within 18 months of the date each transaction was entered. In 2011 and 2010, Westar Energy entered into and settled forward sale transactions with respect to an aggregate of approximately 5.4 million shares of common stock for proceeds of approximately $118.3 million.

During 2013 and 2012, Westar Energy entered into additional forward sale transactions with respect to an aggregate of approximately 2.5 million and 1.8 million shares of common stock respectively, under the March 2013 and April 2010 agreements. During 2013, Westar Energy settled 1.1 million shares, resulting in 3.1 million shares under the March 2013 and April 2010 agreements that had not settled as of December 31, 2013. In February 2014, Westar Energy settled 0.3 million shares with a physical settlement amount of approximately $9.2 million.

The forward sale transactions are entered into at market prices; therefore, the forward sale agreements have no initial fair value. Westar Energy does 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 are initially priced when the transactions are entered into and are subject to certain fixed pricing adjustments during the term of the agreements. Accordingly, assuming physical share settlement, Westar Energy'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.

Assuming physical share settlement of the approximately 12.1 million shares associated with all forward sale transactions as of December 31, 2013, Westar Energy would have received aggregate proceeds of approximately $358.3 million based on a weighted average forward price of $29.73 per share.

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

Preferred Stock Redemption

In May 2012, Westar Energy provided an irrevocable notice of redemption to holders of all of Westar Energy's preferred shares. Pursuant to Westar Energy's Articles of Incorporation, we deposited cash in a separate account to effect the redemption of all of our preferred stock outstanding. Payment was due to holders of the preferred shares effective July 1, 2012. The table below shows the redemption amounts for all series of preferred stock.

Rate	Shares	Principal Outstanding	Call Price	Premium	Total Cost to Redeem
		(Dollars in Thousands)			
4.50%	121,613	$ 12,161	108.0%	$ 973	$ 13,134
4.25%	54,970	5,497	101.5%	82	5,579
5.00%	37,780	3,778	102.0%	76	3,854
	214,363	$ 21,436		$ 1,131	$ 22,567

Summary of Cash Flows

	Year Ended December 31,		
	2013	2012	2011
	(In Thousands)		
Cash flows from (used in):			
Operating activities	$ 702,803	$ 599,106	$ 462,696
Investing activities	(641,901)	(797,337)	(701,516)
Financing activities	(62,244)	200,521	241,431
Net (decrease) increase in cash and cash equivalents	$ (1,342)	$ 2,290	$ 2,611

Cash Flows from Operating Activities

Cash flows from operating activities increased $103.7 million in 2013 compared to 2012 due principally to our having received about $74.3 million more from retail and wholesale customers, our having paid approximately $40.9 million less for pension and post retirement contributions, our having paid $29.7 million in 2012 to settle treasury yield hedge transactions, and our receiving $9.6 million more in COLI death proceeds. Increases were offset partially by our having paid approximately $65.6 million more for the planned Wolf Creek refueling and maintenance outage.

The $136.4 million increase in 2012 compared to 2011 was due principally to our having paid approximately $100.9 million less for fuel and purchased power, our having received about $96.3 million more from retail customers and our having paid $56.3 million in 2011 to settle litigation. Increases were offset partially by our having received approximately $42.0 million less from wholesale customers, our having paid $29.7 million in 2012 to settle treasury yield hedge transactions, our having received $13.1 million less in income tax refunds and our having contributed $10.3 million more to pension and post-retirement benefit plans.

Cash Flows used in Investing Activities

Cash flows used in investing activities decreased $155.4 million from 2012 to 2013 due primarily to increased proceeds from investment in corporate owned life insurance of $114.1 million and decreased investment in property, plant and equipment of $30.1 million.

Cash flows used in investing activities increased $95.8 million from 2011 to 2012 due primarily to our having invested an additional $112.8 million in additions to property, plant and equipment, which was attributable principally to additions at our power plants, including air quality controls, and the addition of transmission facilities. The increased investment in 2012 was partially offset by our having received $32.2 million more in proceeds from our investment in COLI.

Cash Flows from (used in) Financing Activities

Cash flows from financing activities decreased $262.8 million in 2013 compared to 2012. The decrease was due primarily to our having borrowed $258.1 million less in short term debt and our having repaid $110.6 million more for borrowings against the cash surrender value of corporate owned life insurance. This decrease was partially offset by our having paid $120.6 million less to retire long-term debt.

The $40.9 million decrease in 2012 compared to 2011 was due principally to our having received $287.9 million less in proceeds from the issuance of common stock, which was attributable principally to our having issued shares in 2011 to settle forward transactions, and our having retired $220.2 million more of long-term debt due to favorable conditions in the capital markets. Contributing to the decrease was our having repaid $31.4 million more for borrowings against the cash surrender value of COLI, our having established a $22.6 million restricted cash account to fund the redemption of preferred stock and our having paid $19.9 million more for dividends as a result principally of our having increased our common stock dividend from $1.28 per share in 2011 to $1.32 per share in 2012. Partially offsetting the decreases was our having received $541.4 million in proceeds from long-term debt issuances. The proceeds were used to repay short-term debt, which was used to purchase capital equipment, to redeem bonds, and for working capital and general corporate purposes.

Future Cash Requirements

Our business requires significant capital investments. Through 2016, 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 projects 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, short-term borrowings and 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 us and our 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 and consolidated financial results.

Capital expenditures for 2013 and anticipated capital expenditures, including costs of removal, for 2014 through 2016 are shown in the following table.

	Actual 2013	2014	2015	2016
	(In Thousands)			
Generation:				
Replacements and other	$ 201,395	$ 181,600	$ 173,100	$ 136,800
Environmental	262,441	237,000	112,000	21,900
Nuclear fuel	4,129	52,900	28,600	30,200
Transmission (a)	168,662	179,100	186,900	203,400
Distribution	107,993	137,200	147,700	157,300
Other	35,478	26,200	30,700	41,400
Total capital expenditures	$ 780,098	$ 814,000	$ 679,000	$ 591,000

(a) In addition to amounts listed, we are investing in Prairie Wind Transmission. In 2013, we incurred $4.0 million of expenditures related to this investment. In 2014 we plan to incur expenditures related to Prairie Wind Transmission of $6.7 million. We do not anticipate any further investment related to Prairie Wind Transmission in 2015 and 2016.

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 regulatory requirements, changing costs, delays or advances 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 possibly material changes in actual costs. In addition, these amounts do not include any estimates for potential new environmental requirements.

We will also need significant amounts of cash in the future to meet our long-term debt obligations. The principal amounts of our long-term debt maturities as of December 31, 2013, are as follows.

Year	Long-term debt	Long-term debt of VIEs
	(In Thousands)	
2014	$ 250,000	$ 27,479
2015	—	27,933
2016	—	28,309
2017	125,000	26,842
2018	300,000	28,538
Thereafter	2,549,440	82,581
Total maturities	$ 3,224,440	$ 221,682

Pension Obligation

The amount we contribute to our pension plan for future periods is not yet known, however, we expect to fund our pension plan each year at least to a level equal to 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 $27.5 million to our pension trust in 2013 and $56.7 million in 2012. We expect to contribute approximately $30.8 million in 2014. In 2013 and 2012, we also funded $7.6 million and $13.9 million, respectively, of Wolf Creek's pension plan contributions. In 2014, we plan to contribute $5.4 million to fund 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" above and in Note 16 of the Notes to Consolidated Financial Statements, "Common Stock," Westar Energy entered into several forward sale agreements with banks in 2013. 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, 2013.

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.

Contractual Cash Obligations

The following table summarizes the projected future cash payments for our contractual obligations existing as of December 31, 2013.

	Total	2014	2015 - 2016	2017 - 2018		Thereafter
			(In Thousands)			
Long-term debt (a)	$ 3,224,440	$ 250,000	$ —	$ 425,000		$ 2,549,440
Long-term debt of VIEs (a)	221,682	27,479	56,242	55,380		82,581
Interest on long-term debt (b)	2,698,143	173,875	317,749	308,093		1,898,426
Interest on long-term debt of VIEs	50,209	12,183	19,128	12,594		6,304
Long-term debt, including interest	6,194,474	463,537	393,119	801,067		4,536,751
Pension and post-retirement benefit expected contributions (c)	39,700	39,700	—	—		—
Capital leases (d)	99,044	6,464	11,070	9,375		72,135
Operating leases (e)	65,588	14,384	22,212	13,631		15,361
Other obligations of VIEs (f)	14,980	1,038	3,626	10,316		—
Fossil fuel (g)	1,287,180	199,289	350,411	347,846		389,634
Nuclear fuel (h)	282,569	42,196	39,303	44,806	39,443	156,264
Transmission service (i)	33,791	7,267	12,133	5,399		8,992
Unconditional purchase obligations	312,171	258,293	46,415	7,463		—
Total contractual obligations (j)	$ 8,329,497	$ 1,032,168	$ 878,289	$ 1,239,903		$ 5,179,137

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(a) See Note 9 of the Notes to Consolidated Financial Statements, "Long-Term Debt," for individual maturities.
(b) We calculate interest on our variable rate debt based on the effective interest rates as of December 31, 2013.
(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 rail cars 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) Includes obligations to SPP for transmission service payments. See Note 13 of the Notes to Consolidated Financial Statements, "Commitments and Contingencies," for additional information.
(j) We have $1.9 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, 2013.

Commercial Commitments

Our commercial commitments as of December 31, 2013, consist of outstanding letters of credit that expire in 2014, some of which automatically renew annually. The letters of credit are comprised of $11.7 million related to new transmission projects, $3.3 million related to energy marketing and trading activities, $0.8 million related to workers' compensation, and $3.4 million related to other operating activities, for a total outstanding balance of $19.2 million.

OTHER INFORMATION

Changes in Prices

KCC Proceedings

We filed an application with the KCC in February 2014 to adjust our prices to include updated transmission costs as reflected in our transmission formula rate effective in January 2014 discussed below. If approved, we estimate that the new prices will increase our annual retail revenues by approximately $43.6 million. We expect the KCC to issue an order on our request in March 2014.

In December 2013, the KCC approved an order allowing us to adjust our prices to include costs incurred for property taxes. The new prices were effective in January 2014 and are expected to increase our annual retail revenues by approximately $12.7 million.

In November 2013, the KCC issued an order allowing us to adjust our prices to include the additional investment in the La Cygne environmental upgrades and to reflect cost reductions elsewhere. The new prices are expected to increase our annual retail revenues by approximately $30.7 million.

In May 2013, the KCC issued an order allowing us to adjust our prices to include costs associated with 2012 investments in environmental projects. The new prices were effective in June 2013 and are expected to increase our annual retail revenues by approximately $27.3 million.

In March 2013, we adjusted our prices to included updated transmission costs as reflected in the transmission formula rate discussed below. The KCC issued an order in July 2013 approving our adjustment which is expected to increase our annual retail revenues by approximately $11.8 million.

FERC Proceedings

In October 2013, we posted our updated transmission formula rate that includes projected 2014 transmission capital expenditures and operating costs. The updated rate was effective in January 2014 and is expected to increase our annual transmission revenues by approximately $44.3 million.

Our transmission formula rate that includes projected 2013 transmission capital expenditures and operating costs was effective in January 2013 and is expected to increase our annual transmission revenues by approximately $12.2 million. This updated rate provided the basis for our request with the KCC to adjust our retail prices to include updated transmission costs as discussed above.

Wolf Creek Outage

Wolf Creek normally operates on an 18-month planned refueling and maintenance outage schedule. However, as a result of an unscheduled maintenance outage at Wolf Creek in 2012 coupled with the longer than planned refueling and maintenance outage in 2011, we were able to defer the fall 2012 planned refueling and maintenance outage to the first quarter of 2013. The next planned refueling and maintenance outage will be in the first quarter of 2015. During the first quarter of 2014, Wolf Creek will undergo a planned maintenance outage. The outage is not part of a refueling outage and therefore will be expensed as incurred. We expect our share of the 2014 outage costs to be approximately $9.0 million.

New Financial Regulation

In 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. We do not expect compliance with related regulations to have a significant impact on our business.

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 $4.4 million as of December 31, 2013, and we expect to recognize these costs over a remaining weighted-average period of 1.7 years. Total unrecognized compensation cost related to RSU awards with performance measures was $4.0 million as of December 31, 2013, and we expect to recognize these costs over a remaining weighted-average period of 1.7 years.

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. In addition, our investments in trusts to fund nuclear plant decommissioning and to fund non-qualified retirement benefits give rise to security price risk. Many of the securities in these trusts are exposed to price fluctuations in the capital markets.

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.

We use various types of fuel, including coal, natural gas, uranium and diesel to operate our plants and also purchase power to meet customer demand. Our prices and consolidated financial results are exposed to market risks from commodity price changes for electricity and other energy-related products as well as from interest rates. Volatility in these markets impacts our costs of purchased power, costs of fuel for our generating plants and our participation in energy markets. We strive to manage our customers' and our exposure to these market risks through regulatory, 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.

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 significantly from assumptions. Accordingly, VaR may not accurately reflect our levels of exposure. The energy trading and market-based wholesale portfolio VaR amounts for 2013 and 2012 were as follows:

	2013	2012
	(In Thousands)	
High	$ 205	$ 309
Low	9	10
Average	83	84

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 exposure to variable interest rate debt, diversifying 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 $534.0 million of variable rate debt and current maturities of fixed rate debt as of December 31, 2013. A 100 basis point change in interest rates applicable to this debt would impact income before income taxes on an annualized basis by approximately $2.8 million. As of December 31, 2013, 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 led 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 could increase our borrowing costs. Furthermore, a decline in interest rates generally can serve to increase our pension and post-retirement benefit obligations.

Security Price Risk

We maintain the NDT, as required by the NRC and Kansas statute, to fund certain costs of nuclear plant decommissioning. As of December 31, 2013, investments in the NDT were allocated 50% to equity securities, 26% to debt securities, 10% to combination debt/equity securities, 9% to alternative investments, 5% to real estate securities and less than 1% to cash equivalents. As of December 31, 2013 and 2012, the fair value of the NDT investments was $175.6 million and $150.8 million, respectively. Changes in interest rates and/or other market changes resulting in a 10% decrease in the value of the securities would have resulted in a $17.6 million decrease in the value of the NDT as of December 31, 2013.

We also maintain a trust to fund non-qualified retirement benefits. As of December 31, 2013, investments in the trust were comprised of 65% equity securities, 35% debt securities and less than 1% cash equivalents. The fair value of the investments in this trust was $34.9 million as of December 31, 2013, and $43.5 million as of December 31, 2012. Changes in interest rates and/or other market changes resulting in a 10% decrease in the value of the securities would have resulted in a $3.5 million decrease in the value of the trust as of December 31, 2013.

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, many of the 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 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, 2013. 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, 2013, 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, 2013, based on criteria established in *Internal Control - Integrated Framework (1992)* 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, 2013, based on the criteria established in *Internal Control - Integrated Framework (1992)* 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 of the Company as of and for the year ended December 31, 2013 of the Company and our report dated February 26, 2014 expressed an unqualified opinion on those financial statements and financial statement schedule.

/s/ Deloitte & Touche LLP

Kansas City, Missouri
February 26, 2014

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, 2013 and 2012, and the related consolidated statements of income, changes in equity, and cash flows for each of the three years in the period ended December 31, 2013. 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, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, 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.

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, 2013, based on the criteria established in *Internal Control-Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2014 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Kansas City, Missouri
February 26, 2014

WESTAR ENERGY, INC.
CONSOLIDATED BALANCE SHEETS
(Dollars in Thousands, Except Par Values)

	As of December 31,	
	2013	2012
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 4,487	$ 5,829
Accounts receivable, net of allowance for doubtful accounts of $4,596 and $4,916, respectively	250,036	224,439
Fuel inventory and supplies	239,511	249,016
Deferred tax assets	37,927	—
Prepaid expenses	15,821	15,847
Regulatory assets	135,408	114,895
Other	23,608	33,049
Total Current Assets	706,798	643,075
PROPERTY, PLANT AND EQUIPMENT, NET	7,551,916	7,013,765
PROPERTY, PLANT AND EQUIPMENT OF VARIABLE INTEREST ENTITIES, NET	296,626	321,975
OTHER ASSETS:		
Regulatory assets	620,006	887,777
Nuclear decommissioning trust	175,625	150,754
Other	246,140	247,885
Total Other Assets	1,041,771	1,286,416
TOTAL ASSETS	$ 9,597,111	$ 9,265,231
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Current maturities of long-term debt	$ 250,000	$ —
Current maturities of long-term debt of variable interest entities	27,479	25,942
Short-term debt	134,600	339,200
Accounts payable	233,351	180,825
Accrued dividends	43,604	41,743
Accrued taxes	69,742	58,624
Accrued interest	80,457	77,891
Regulatory liabilities	35,982	37,557
Other	80,184	84,359
Total Current Liabilities	955,399	846,141
LONG-TERM LIABILITIES:		
Long-term debt, net	2,968,958	2,819,271
Long-term debt of variable interest entities, net	194,802	222,743
Deferred income taxes	1,361,418	1,197,837
Unamortized investment tax credits	192,265	191,512
Regulatory liabilities	293,574	285,618
Accrued employee benefits	331,558	564,870
Asset retirement obligations	160,682	152,648
Other	69,924	74,336
Total Long-Term Liabilities	5,573,181	5,508,835
COMMITMENTS AND CONTINGENCIES (See Notes 13 and 15)		
EQUITY:		
Westar Energy, Inc. Shareholders' Equity:		
Common stock, par value $5 per share; authorized 275,000,000 shares; issued and outstanding 128,254,229 shares and 126,503,748 shares, respective to each date	641,271	632,519
Paid-in capital	1,696,727	1,656,972
Retained earnings	724,776	606,649
Total Westar Energy, Inc. Shareholders' Equity	3,062,774	2,896,140
Noncontrolling Interests	5,757	14,115
Total Equity	3,068,531	2,910,255
TOTAL LIABILITIES AND EQUITY	$ 9,597,111	$ 9,265,231

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,		
	2013	2012	2011
REVENUES	$ 2,370,654	$ 2,261,470	$ 2,170,991
OPERATING EXPENSES:			
Fuel and purchased power	634,797	589,990	630,793
SPP network transmission costs	178,604	166,547	132,164
Operating and maintenance	359,060	342,055	332,989
Depreciation and amortization	272,593	270,464	285,322
Selling, general and administrative	224,133	226,012	184,695
Taxes other than income tax	122,282	104,269	92,599
Total Operating Expenses	1,791,469	1,699,337	1,658,562
INCOME FROM OPERATIONS	579,185	562,133	512,429
OTHER INCOME (EXPENSE):			
Investment earnings	10,056	7,411	9,301
Other income	35,609	35,378	8,652
Other expense	(18,099)	(19,987)	(18,398)
Total Other Income (Expense)	27,566	22,802	(445)
Interest expense	182,167	176,337	172,460
INCOME BEFORE INCOME TAXES	424,584	408,598	339,524
Income tax expense	123,721	126,136	103,344
NET INCOME	300,863	282,462	236,180
Less: Net income attributable to noncontrolling interests	8,343	7,316	5,941
NET INCOME ATTRIBUTABLE TO WESTAR ENERGY, INC.	292,520	275,146	230,239
Preferred dividends	—	1,616	970
NET INCOME ATTRIBUTABLE TO COMMON STOCK	$ 292,520	$ 273,530	$ 229,269
BASIC AND DILUTED EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING ATTRIBUTABLE TO WESTAR ENERGY (see Note 2):			
Basic earnings per common share	$ 2.29	$ 2.15	$ 1.95
Diluted earnings per common share	$ 2.27	$ 2.15	$ 1.93
AVERAGE EQUIVALENT COMMON SHARES OUTSTANDING	127,462,994	126,711,869	116,890,552
DIVIDENDS DECLARED PER COMMON SHARE	$ 1.36	$ 1.32	$ 1.28

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,		
	2013	2012	2011
CASH FLOWS FROM (USED IN) OPERATING ACTIVITIES:			
Net income	$ 300,863	$ 282,462	$ 236,180
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	272,593	270,464	285,322
Amortization of nuclear fuel	22,690	24,369	21,151
Amortization of deferred regulatory gain from sale leaseback	(5,495)	(5,495)	(5,495)
Amortization of corporate-owned life insurance	15,149	28,792	25,650
Non-cash compensation	8,188	7,255	8,422
Net deferred income taxes and credits	123,307	126,248	111,723
Stock-based compensation excess tax benefits	(576)	(1,698)	(1,180)
Allowance for equity funds used during construction	(14,143)	(11,706)	(5,550)
Gain on sale of non-utility investment	—	—	(7,246)
Gain on settlement of contractual obligations with former officers	—	—	(22,039)
Changes in working capital items:			
Accounts receivable	(24,649)	2,408	(1,638)
Fuel inventory and supplies	10,124	(19,227)	(21,485)
Prepaid expenses and other	(12,316)	(3,630)	(50,138)
Accounts payable	7,856	(19,161)	3,008
Accrued taxes	14,218	11,937	18,633
Other current liabilities	(52,829)	(105,169)	(107,012)
Changes in other assets	(4,167)	13,015	(10,167)
Changes in other liabilities	41,990	(1,758)	(15,443)
Cash Flows from Operating Activities	702,803	599,106	462,696
CASH FLOWS FROM (USED IN) INVESTING ACTIVITIES:			
Additions to property, plant and equipment	(780,098)	(810,209)	(697,451)
Purchase of securities - trusts	(66,668)	(20,473)	(49,737)
Sale of securities - trusts	81,994	21,604	47,534
Investment in corporate-owned life insurance	(17,724)	(18,404)	(19,214)
Proceeds from investment in corporate-owned life insurance	147,658	33,542	1,295
Proceeds from federal grant	876	4,775	8,561
Investment in affiliated company	(4,947)	(8,669)	(1,943)
Proceeds from sale of non-utility investments	—	—	9,246
Other investing activities	(2,992)	497	193
Cash Flows used in Investing Activities	(641,901)	(797,337)	(701,516)
CASH FLOWS FROM (USED IN) FINANCING ACTIVITIES:			
Short-term debt, net	(205,241)	52,900	54,081
Proceeds from long-term debt	492,347	541,374	—
Retirements of long-term debt	(100,000)	(220,563)	(371)
Retirements of long-term debt of variable interest entities	(25,942)	(28,114)	(30,159)
Repayment of capital leases	(2,995)	(2,679)	(2,233)
Borrowings against cash surrender value of corporate-owned life insurance	59,565	67,791	67,562
Repayment of borrowings against cash surrender value of corporate-owned life insurance	(145,418)	(34,838)	(3,421)
Stock-based compensation excess tax benefits	576	1,698	1,180
Preferred stock redemption	—	(22,567)	—
Issuance of common stock	32,906	6,996	294,942
Distributions to shareholders of noncontrolling interests	(2,419)	(3,295)	(1,917)
Cash dividends paid	(162,904)	(158,182)	(138,233)
Other financing activities	(2,719)	—	—
Cash Flows (used in) from Financing Activities	(62,244)	200,521	241,431
NET (DECREASE) INCREASE IN CASH AND CASH EQUIVALENTS	(1,342)	2,290	2,611
CASH AND CASH EQUIVALENTS:			
Beginning of period	5,829	3,539	928
End of period	$ 4,487	$ 5,829	$ 3,539

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, Inc. Shareholders							
	Cumulative preferred stock shares	Cumulative preferred stock	Common stock shares	Common stock	Paid-in capital	Retained earnings	Non-controlling interests	Total equity
Balance as of December 31, 2010	214,363	$ 21,436	112,128,068	$ 560,640	$ 1,398,580	$ 423,647	$ 6,070	$ 2,410,373
Net income	—	—	—	—	—	230,239	5,941	236,180
Issuance of stock	—	—	12,951,207	64,756	230,186	—	—	294,942
Issuance of stock for compensation and reinvested dividends	—	—	619,121	3,096	4,331	—	—	7,427
Tax withholding related to stock compensation	—	—	—	—	(3,141)	—	—	(3,141)
Preferred dividends	—	—	—	—	—	(970)	—	(970)
Dividends on common stock ($1.28 per share)	—	—	—	—	—	(151,700)	—	(151,700)
Stock compensation expense	—	—	—	—	8,367	—	—	8,367
Tax benefit on stock compensation	—	—	—	—	1,180	—	—	1,180
Distributions to shareholders of noncontrolling interests	—	—	—	—	—	—	(1,917)	(1,917)
Balance as of December 31, 2011	214,363	21,436	125,698,396	628,492	1,639,503	501,216	10,094	2,800,741
Net income	—	—	—	—	—	275,146	7,316	282,462
Issuance of stock	—	—	242,463	1,212	5,784	—	—	6,996
Issuance of stock for compensation and reinvested dividends	—	—	562,889	2,815	6,274	—	—	9,089
Tax withholding related to stock compensation	—	—	—	—	(3,490)	—	—	(3,490)
Stock Redemption	(214,363)	(21,436)	—	—	—	—	—	(21,436)
Preferred dividends	—	—	—	—	—	(1,616)	—	(1,616)
Dividends on common stock ($1.32 per share)	—	—	—	—	—	(168,097)	—	(168,097)
Stock compensation expense	—	—	—	—	7,203	—	—	7,203
Tax benefit on stock compensation	—	—	—	—	1,698	—	—	1,698
Distributions to shareholders of noncontrolling interests	—	—	—	—	—	—	(3,295)	(3,295)
Balance as of December 31, 2012	—	—	126,503,748	632,519	1,656,972	606,649	14,115	2,910,255
Net income	—	—	—	—	—	292,520	8,343	300,863
Issuance of stock	—	—	1,256,391	6,282	26,624	—	—	32,906
Issuance of stock for compensation and reinvested dividends	—	—	494,090	2,470	7,171	—	—	9,641
Tax withholding related to stock compensation	—	—	—	—	(2,719)	—	—	(2,719)
Dividends on common stock ($1.36 per share)	—	—	—	—	—	(174,393)	—	(174,393)
Stock compensation expense	—	—	—	—	8,103	—	—	8,103
Tax benefit on stock compensation	—	—	—	—	576	—	—	576
Deconsolidation of noncontrolling interests	—	—	—	—	—	—	(14,282)	(14,282)
Distributions to shareholders of noncontrolling interests	—	—	—	—	—	—	(2,419)	(2,419)
Balance as of December 31, 2013	—	$ —	128,254,229	$ 641,271	$ 1,696,727	$ 724,776	$ 5,757	$ 3,068,531

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 693,000 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 reportable 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 ongoing basis, including those related to depreciation, unbilled revenue, valuation of investments, forecasted fuel costs included in our retail energy cost adjustment (RECA) billed to customers, income taxes, pension and 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.

Fuel Inventory and Supplies

We state fuel inventory and supplies at average cost. Following are the balances for fuel inventory and supplies stated separately.

	As of December 31,	
	2013	2012
	(In Thousands)	
Fuel inventory	$ 78,368	$ 94,664
Supplies	161,143	154,352
Total	$ 239,511	$ 249,016

Property, Plant and Equipment

We record the value of property, plant and equipment, including that 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 other income (for equity funds) and interest expense (for borrowed funds) for the amount of AFUDC capitalized as construction cost on the accompanying consolidated statements of income as follows:

	Year Ended December 31,		
	2013	2012	2011
	(Dollars In Thousands)		
Borrowed funds	$ 11,706	$ 10,399	$ 5,589
Equity funds	14,143	11,706	5,550
Total	$ 25,849	$ 22,105	$ 11,139
Average AFUDC Rates	4.8%	5.0%	3.6%

We charge maintenance costs and replacements 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 the period between planned outages incremental maintenance costs incurred for such outages. 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. The depreciation rates are based on an average annual composite basis using group rates that approximated 2.5% in 2013, 2.6% in 2012 and 3.0% in 2011.

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

	Years		
Fossil fuel generating facilities	6	to	78
Nuclear fuel generating facility	55	to	71
Wind generating facilities	19	to	20
Transmission facilities	15	to	75
Distribution facilities	22	to	68
Other	5	to	30

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 $46.2 million as of December 31, 2013, and $69.2 million as of December 31, 2012. The cost of nuclear fuel charged to fuel and purchased power expense was $26.5 million in 2013, $28.3 million in 2012 and $24.6 million in 2011.

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,	
	2013	2012
	(In Thousands)	
Cash surrender value of policies	$ 1,289,457	$ 1,370,788
Borrowings against policies	(1,156,341)	(1,241,343)
Corporate-owned life insurance, net	$ 133,116	$ 129,445

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

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 recorded estimated unbilled revenue of $60.1 million as of December 31, 2013, and $62.5 million as of December 31, 2012.

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 the extent capital losses, operating losses, or tax credits will be carried forward to future periods. 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 Tax

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

Earnings Per Share

We have participating securities in the form of unvested restricted share units (RSUs) with nonforfeitable rights to dividend equivalents that receive dividends on an equal basis with dividends declared on 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 and RSUs with forfeitable rights to dividend equivalents. We compute the dilutive effect of potential issuances of common shares using the treasury stock method.

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

	Year Ended December 31,		
	2013	2012	2011
	(Dollars In Thousands, Except Per Share Amounts)		
Net income	$ 300,863	$ 282,462	$ 236,180
Less: Net income attributable to noncontrolling interests	8,343	7,316	5,941
Net income attributable to Westar Energy, Inc.	292,520	275,146	230,239
Less: Preferred dividends	—	1,616	970
Net income allocated to RSUs	810	778	772
Net income allocated to common stock	$ 291,710	$ 272,752	$ 228,497
Weighted average equivalent common shares outstanding – basic	127,462,994	126,711,869	116,890,552
Effect of dilutive securities:			
RSUs	17,195	97,757	188,025
Forward sale agreements	818,505	89,160	1,211,645
Weighted average equivalent common shares outstanding – diluted (a)	128,298,694	126,898,786	118,290,222
Earnings per common share, basic	$ 2.29	$ 2.15	$ 1.95
Earnings per common share, diluted	$ 2.27	$ 2.15	$ 1.93

(a) For the years ended December 31, 2013, 2012 and 2011, we had no antidilutive shares.

Supplemental Cash Flow Information

	Year Ended December 31,		
	2013	2012	2011
	(In Thousands)		
CASH PAID FOR (RECEIVED FROM):			
Interest on financing activities, net of amount capitalized	$ 148,691	$ 143,564	$ 145,570
Interest on financing activities of VIEs	13,892	16,214	18,167
Income taxes, net of refunds	(11)	(4,378)	(17,519)
NON-CASH INVESTING TRANSACTIONS:			
Property, plant and equipment additions	127,544	89,354	105,435
Property, plant and equipment of VIEs	(14,282)	—	—
NON-CASH FINANCING TRANSACTIONS:			
Issuance of common stock for reinvested dividends and compensation plans	9,641	9,089	7,427
Deconsolidation of VIEs	(14,282)	—	—
Assets acquired through capital leases	334	10,683	43,011

Investment Earnings - Sale of Non-utility Investment

In 2011, we recorded a $7.2 million gain on the sale of a non-utility investment.

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,	
	2013	2012
	(In Thousands)	
Regulatory Assets:		
Deferred employee benefit costs	$ 277,122	$ 542,174
Amounts due from customers for future income taxes, net	163,742	169,091
Depreciation	71,047	73,672
Debt reacquisition costs	63,882	67,721
Ad valorem tax	34,492	21,812
Wolf Creek outage	29,026	14,143
Treasury yield hedges	27,594	28,573
Asset retirement obligations	23,555	22,633
Retail energy cost adjustment	22,138	4,262
Disallowed plant costs	15,964	16,106
Energy efficiency program costs	14,477	18,835
Storm costs	1,483	11,076
Other regulatory assets	10,892	12,574
Total regulatory assets	$ 755,414	$ 1,002,672
Regulatory Liabilities:		
Removal costs	$ 114,148	$ 128,971
Deferred regulatory gain from sale leaseback	86,551	92,046
Nuclear decommissioning	43,272	25,937
La Cygne dismantling costs	20,505	18,093
Other post-retirement benefits costs	19,000	10,722
Retail energy cost adjustment	15,414	16,595
Kansas tax credits	11,076	10,781
Jurisdictional allowance for funds used during construction	7,893	4,457
Gain on sale of oil	4,278	6,219
Fuel supply and electricity contracts	2,635	4,387
Other regulatory liabilities	4,784	4,967
Total regulatory liabilities	$ 329,556	$ 323,175

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 $223.5 million for pension and post-retirement benefit obligations and $53.7 million for actual pension expense in excess of the amount of such expense recognized in setting our prices. The decrease from 2012 to 2013 is primarily attributable to the favorable increase in the funded status of our and Wolf Creek's pension and post-retirement plans. During 2014, we will amortize to expense approximately $24.9 million of the benefit obligations and approximately $9.8 million of the excess pension expense. As authorized in the April 2012 Kansas Corporation Commission (KCC) order discussed below, we are amortizing the excess pension expense as of the time of our filing with the KCC over a five-year period. 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. We do not earn a return on this asset.

- **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.

- **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.

- **Wolf Creek outage:** We defer the expenses associated with Wolf Creek's scheduled refueling and maintenance outages and amortize these expenses during the period between planned outages. We do not earn a return on this asset.

- **Treasury yield hedges:** Represents the effective portion of losses on treasury yield hedge transactions. This amount will be amortized to interest expense over the term of the related debt. See Note 4, "Financial Instruments and Trading Securities—Cash Flow Hedges," for additional information regarding our treasury yield hedge transactions. We do not earn a return on 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.

- **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 have two retail jurisdictions, each with a separate cost of fuel. For the reporting period, this resulted in us simultaneously reporting both a regulatory asset and a regulatory liability for this item. We do not earn a return on this asset.

- **Disallowed plant costs:** Originally there was a decision to disallow certain costs related to the Wolf Creek plant. Subsequently, in 1987, the KCC revised its original conclusion and provided for recovery of an indirect disallowance with no return on investment. This regulatory asset represents the present value of the future expected revenues to be provided to recover these costs, net of the amounts amortized.

- **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.

- **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 will amortize the remaining costs over a two-year period and no longer 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. We do not earn a return on any of these assets.

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.

- **Deferred regulatory gain from sale leaseback:** Represents the gain KGE recorded on the 1987 sale and leaseback of its 50% interest in La Cygne Generation Station (La Cygne) unit 2. We amortize the gain over the lease term.

- **Nuclear decommissioning:** We have a legal obligation to decommission Wolf Creek at the end of its useful life. This amount represents the difference between the fair value of the assets held in a decommissioning trust and the amount recorded for our ARO. See Note 4, "Financial Instruments and Trading Securities," Note 5, "Financial Investments" and Note 14, "Asset Retirement Obligations," for information regarding our nuclear decommissioning trust (NDT) and our ARO.

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

- **Other post-retirement benefits costs:** Includes $6.7 million for post-retirement obligations and $12.3 million of other post-retirement benefits expense recognized in setting our prices in excess of actual other post-retirement benefits expense. We amortize the amount over a five-year period.

- **Retail energy cost adjustment:** We are allowed to adjust our retail prices to reflect changes in the cost of fuel and purchased power needed to serve our customers. We bill customers based on our estimated costs. This item represents the amount we collected from customers that was in excess of our actual cost of fuel and purchased power. We will refund to customers this excess recovery over a one-year period. We have two retail jurisdictions, each with a separate cost of fuel. For the reporting period, this resulted in us simultaneously reporting both a regulatory asset and a regulatory liability for this item.

- **Kansas tax credits:** This item 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.

- **Jurisdictional allowance for funds used during construction:** This item represents AFUDC that is accrued subsequent to the time the associated construction charges are included in our rates and prior to the time the charges are placed in service. The AFUDC is amortized to depreciation expense over the useful life of the asset that is placed in service.

- **Gain on sale of oil:** We discontinued the use of a certain type of oil in our plants. As a result, we sold this oil inventory for a gain. This item represents the remaining portion of the gain that will be refunded to customers over a three-year period.

- **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.

- **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.

KCC Proceedings

General and Abbreviated Rate Reviews

In November 2013, the KCC issued an order allowing us to adjust our prices to include the additional investment in the La Cygne environmental upgrades, as discussed below, and to reflect cost reductions elsewhere. The new prices are expected to increase our annual retail revenues by approximately $30.7 million.

In April 2012, the KCC issued an order expected to increase our annual retail revenues by approximately $50.0 million. In addition, we revised our depreciation rates to reflect changes in the estimated useful lives of some of our depreciable assets. The change in estimate will decrease annual depreciation expense by $43.6 million. The new prices were effective shortly after having received the order.

Environmental Costs

In August 2011, the KCC issued an order ruling that Kansas City Power & Light Company's (KCPL) decision to make environmental upgrades at La Cygne to comply with environmental regulations is prudent and the $1.2 billion project cost estimate is reasonable. We have a 50% interest in La Cygne and intervened in the proceeding. The KCC denied our request to collect our approximately $610.0 million share of the capital investment for the environmental upgrades through our environmental cost recovery rider (ECRR). However, as noted above, we received an order regarding an abbreviated rate review to update our prices to include a portion of the capital costs associated with the project.

We also make annual filings with the KCC to adjust our prices to include costs associated with investments in air quality equipment made during the prior year. In the most recent three years, the KCC issued orders related to such filings allowing us to increase our annual retail revenues by approximately:

- $27.3 million effective in June 2013;
- $19.5 million effective in June 2012; and
- $10.4 million effective in June 2011.

Transmission Costs

We make annual filings with the KCC to adjust our prices to include updated transmission costs as reflected in our transmission formula rate discussed below. In the most recent three years, the KCC issued orders related to such filings allowing us to increase our annual retail revenues by approximately:

- $11.8 million effective in March 2013;
- $36.7 million effective in April 2012; and
- $17.4 million effective in April 2011.

Energy Efficiency

We make annual filings with the KCC to adjust our prices to include previously deferred amounts associated with various energy efficiency programs. In the most recent three years, the KCC issued orders related to such filings allowing us to adjust our annual retail revenues by approximately:

- $1.3 million decrease effective in November 2013;
- $1.1 million increase effective in October 2012; and
- $4.9 million increase effective in November 2011.

Property Tax Surcharge

We make annual filings with the KCC to adjust our prices to include the cost incurred for property taxes. In the most recent three years, the KCC issued orders related to such filings allowing us to increase our annual retail revenues by approximately:

- $15.2 million effective in January 2013;
- $5.9 million effective in January 2012; and
- $0.7 million effective in January 2011.

FERC Proceedings

In October of each year, we post an updated transmission formula rate that includes projected transmission capital expenditures and operating costs for the following year. This rate provides the basis for our annual request with the KCC to adjust our retail prices to include updated transmission costs as noted above. In the most recent three years, we posted our transmission formula rate which was expected to increase our annual transmission revenues by approximately:

- $12.2 million effective in January 2013;
- $38.2 million effective in January 2012; and
- $15.9 million effective in January 2011.

4. FINANCIAL INSTRUMENTS AND TRADING SECURITIES

Values of Financial and Derivative Instruments

GAAP establishes a hierarchical 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 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.

- 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.

- 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. Level 3 includes investments in private equity, real estate securities and other alternative investments, which are measured at net asset value.

We record 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, a level 2 measurement, 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.

All of our level 2 investments are held in investment funds that are measured at fair value using daily net asset values. In addition, we maintain certain level 3 investments in private equity, alternative investments and real estate securities that are also measured at fair value using net asset value, but require significant unobservable market information to measure the fair value of the underlying investments. The underlying investments in private equity are measured at fair value utilizing both market- and income-based models, public company comparables, investment cost or 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. The underlying alternative investments include collateralized debt obligations, mezzanine debt and a variety of other investments. The fair value of these investments is measured using a variety of primarily market-based models utilizing inputs such as security prices, maturity, call features, ratings and other developments related to specific securities. The underlying real estate investments 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.

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 fixed-rate debt.

	As of December 31, 2013		As of December 31, 2012	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In Thousands)			
Fixed-rate debt	$ 3,102,500	$ 3,294,209	$ 2,702,500	$ 3,178,752
Fixed-rate debt of VIEs	221,682	241,241	247,624	275,341

Recurring Fair Value Measurements

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

As of December 31, 2013	Level 1	Level 2	Level 3	Total
	(In Thousands)			
Assets:				
Nuclear Decommissioning Trust:				
Domestic equity	$ —	$ 49,957	$ 5,817	$ 55,774
International equity	—	31,816	—	31,816
Core bonds	—	18,107	—	18,107
High-yield bonds	—	12,902	—	12,902
Emerging market bonds	—	11,055	—	11,055
Other fixed income	—	4,690	—	4,690
Combination debt/equity/other fund	—	17,093	—	17,093
Alternative investments	—	—	15,675	15,675
Real estate securities	—	—	8,511	8,511
Cash equivalents	2	—	—	2
Total Nuclear Decommissioning Trust	2	145,620	30,003	175,625
Trading Securities: (a)				
Domestic equity	—	18,075	—	18,075
International equity	—	4,519	—	4,519
Core bonds	—	12,166	—	12,166
Cash equivalents	166	—	—	166
Total Trading Securities	166	34,760	—	34,926
Total Assets Measured at Fair Value	$ 168	$ 180,380	$ 30,003	$ 210,551
As of December 31, 2012				
Assets:				
Nuclear Decommissioning Trust:				
Domestic equity	$ —	$ 56,157	$ 4,899	$ 61,056
International equity	—	30,041	—	30,041
Core bonds	—	28,350	—	28,350
High-yield bonds	—	8,782	—	8,782
Emerging market bonds	—	6,428	—	6,428
Combination debt/equity fund	—	8,194	—	8,194
Real estate securities	—	—	7,865	7,865
Cash equivalents	38	—	—	38
Total Nuclear Decommissioning Trust	38	137,952	12,764	150,754
Trading Securities:				
Domestic equity	—	22,470	—	22,470
International equity	—	5,744	—	5,744
Core bonds	—	15,104	—	15,104
Cash equivalents	166	—	—	166
Total Trading Securities	166	43,318	—	43,484
Total Assets Measured at Fair Value	$ 204	$ 181,270	$ 12,764	$ 194,238

(a) The decrease in the fair value of trading securities was due to withdrawing $15.3 million.

The following table provides reconciliations of assets and liabilities held in the NDT measured at fair value using significant level 3 inputs for the years ended December 31, 2013 and 2012.

	Domestic Equity	Alternative Investments	Real Estate Securities	Net Balance
	(In Thousands)			
Balance as of December 31, 2012	$ 4,899	$ —	$ 7,865	$ 12,764
Total realized and unrealized gains included in:				
Regulatory liabilities	940	675	646	2,261
Purchases	341	15,000	287	15,628
Sales	(363)	—	(287)	(650)
Balance as of December 31, 2013	$ 5,817	$ 15,675	$ 8,511	$ 30,003
Balance as of December 31, 2011	$ 3,931	$ —	$ 7,095	$ 11,026
Total realized and unrealized gains included in:				
Regulatory liabilities	90	—	770	860
Purchases	891	—	320	1,211
Sales	(13)	—	(320)	(333)
Balance as of December 31, 2012	$ 4,899	$ —	$ 7,865	$ 12,764

Portions of the gains and losses contributing to changes in net assets in the above table are unrealized. The following table summarizes the unrealized gains we recorded to regulatory liabilities on our consolidated financial statements during the years ended December 31, 2013 and 2012, attributed to level 3 assets and liabilities.

	Domestic Equity	Alternative Investments	Real Estate Securities	Net Balance
	(In Thousands)			
Year ended December 31, 2013	$ 577	$ 675	$ 359	$ 1,611
Year ended December 31, 2012	77	—	451	528

Some of our investments in the NDT and our trading securities portfolio are measured at net asset value, 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 additional information on these investments.

	As of December 31, 2013		As of December 31, 2012		As of December 31, 2013	
	Fair Value	Unfunded Commitments	Fair Value	Unfunded Commitments	Redemption Frequency	Length of Settlement
	(In Thousands)					
Nuclear Decommissioning Trust:						
Domestic equity	$ 5,817	$ 2,683	$ 4,899	$ 1,024	(a)	(a)
Alternative investments	15,675	—	—	—	(b)	(b)
Real estate securities	8,511	—	7,865	—	Quarterly	80 days
Total Nuclear Decommissioning Trust	$ 30,003	$ 2,683	$ 12,764	$ 1,024		
Trading Securities:						
Domestic equity	$ 18,075	$ —	$ 22,470	$ —	Upon Notice	1 day
International equity	4,519	—	5,744	—	Upon Notice	1 day
Core bonds	12,166	—	15,104	—	Upon Notice	1 day
Total Trading Securities	34,760	—	43,318	—		
Total	$ 64,763	$ 2,683	$ 56,082	$ 1,024		

(a) This investment is in three 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 2014. Our initial investment in the third fund occurred in the 3rd quarter of 2013. This fund's term will be 15 years, subject to the General Partner's right to extend the term for up to three additional one-year periods.

(b) This fund has an initial lock-up period of 24 months. Redemptions are allowed, on a quarterly basis, after 24 months at the sole discretion of the fund's board of directors. A 65-day notice of redemption is required. There is a holdback on final redemptions.

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 2013, we recorded no additional AROs. In 2012, we recorded $3.1 million of additional AROs. We initially record AROs at fair value for the estimated cost to satisfy the retirement obligation.

We measure the fair value of AROs 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, experts reporting to the Chief Operating Officer must estimate the cost of basic inputs such as labor, energy, materials, timing and disposal and make assumptions on the method of disposal or decommissioning. Our estimates are validated with contractor estimates and when we satisfy other similar obligations. We estimate the cost to satisfy the 2012 ARO layer is approximately $3.1 million.

To determine the appropriate discount rate, we use observable 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."

Derivative Instruments

Cash Flow Hedges

In 2011, we entered into treasury yield hedge transactions to hedge our interest rate risk associated with a $125.0 million portion of a forecasted issuance of fixed rate debt. These transactions were designated and qualified as cash flow hedges and 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 gains or losses on these derivative instruments as a regulatory liability or regulatory asset and amortize such amounts to interest expense over the term of the related debt. During the first quarter of 2012, we settled the treasury yield hedge transactions for a cost of $29.7 million, which will be amortized to interest expense over the 30-year term of the debt issued in March 2012. See Note 9, "Long-Term Debt" for additional information regarding the debt issuance. As of December 31, 2013 and 2012, we had recorded $27.6 million and $28.6 million, respectively, as a regulatory asset.

Price Risk

We use various types of fuel, including coal, natural gas, uranium and diesel to operate our plants and also purchase power to meet customer demand. Our prices and consolidated financial results are exposed to market risks from commodity price changes for electricity and other energy-related products as well as from interest rates. Volatility in these markets impacts our costs of purchased power, costs of fuel for our generating plants and our participation in energy markets. We strive to manage our customers' and our exposure to these market risks through regulatory, 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.

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 exposure to variable interest rate debt, diversifying maturity dates and entering into treasury yield hedge transactions. We may also use other financial derivative instruments such as interest rate swaps.

5. FINANCIAL INVESTMENTS

We report our investments in equity and debt securities at fair value and use the specific identification method to determine their realized gains and losses. We classify these investments as either trading securities or available-for-sale securities as described below.

Trading Securities

We hold equity and debt investments which we classify as trading securities in a trust used to fund certain retirement benefit obligations of $27.0 million and $30.0 million as of December 31, 2013 and 2012, respectively. For additional information on our benefit obligations, see Note 11, "Employee Benefit Plans."

As of December 31, 2013 and 2012, we measured the fair value of trust assets at $34.9 million and $43.5 million, respectively. We include unrealized gains or losses on these securities in investment earnings on our consolidated statements of income. For the years ended December 31, 2013, 2012 and 2011, we recorded unrealized gains of $6.7 million, $4.1 million and $0.3 million, respectively.

Available-for-Sale Securities

We hold investments in a trust 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, 2013, and December 31, 2012. As of December 31, 2013, the fair value of available-for-sale bond funds was $46.8 million. The NDT did not have investments in debt securities outside of investment funds as of December 31, 2013.

Using the specific identification method to determine cost, we realized gains on our available-for-sale securities of $5.3 million in 2013, $0.6 million in 2012 and $1.3 million in 2011. 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 cost, gross unrealized gains and losses, fair value and allocation of investments in the NDT fund as of December 31, 2013 and 2012.

Security Type	Cost	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value	Allocation
	(Dollars In Thousands)				
As of December 31, 2013					
Domestic equity	$ 40,976	$ 14,799	$ (1)	$ 55,774	32%
International equity	26,581	5,266	(31)	31,816	18%
Core bonds	18,287	—	(180)	18,107	10%
High-yield bonds	12,275	627	—	12,902	7%
Emerging market bonds	12,207	—	(1,152)	11,055	6%
Other fixed income	4,684	6	—	4,690	3%
Combination debt/equity/other fund	14,964	2,380	(251)	17,093	10%
Alternative investments	15,000	675	—	15,675	9%
Real estate securities	10,268	—	(1,757)	8,511	5%
Cash equivalents	2	—	—	2	<1%
Total	$ 155,244	$ 23,753	$ (3,372)	$ 175,625	100%
As of December 31, 2012					
Domestic equity	$ 53,598	$ 7,458	$ —	$ 61,056	41%
International equity	28,248	1,793	—	30,041	20%
Core bonds	27,309	1,041	—	28,350	19%
High-yield bonds	8,022	760	—	8,782	6%
Emerging market bonds	6,080	348	—	6,428	4%
Combination debt/equity fund	8,074	120	—	8,194	5%
Real estate securities	9,981	—	(2,116)	7,865	5%
Cash equivalents	38	—	—	38	<1%
Total	$ 141,350	$ 11,520	$ (2,116)	$ 150,754	100%

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, 2013 and 2012.

	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)					
As of December 31, 2013						
Domestic equity	$ 59	$ (1)	$ —	$ —	$ 59	$ (1)
International equity	6,244	(31)	—	—	6,244	(31)
Core bonds	18,107	(180)	—	—	18,107	(180)
Emerging market bonds	11,055	(1,152)	—	—	11,055	(1,152)
Combination debt/equity/other funds	6,283	(251)	—	—	6,283	(251)
Real estate securities	—	—	8,511	(1,757)	8,511	(1,757)
Total	$ 41,748	$ (1,615)	$ 8,511	$ (1,757)	$ 50,259	$ (3,372)
As of December 31, 2012						
Real estate securities	$ —	$ —	$ 7,865	$ (2,116)	$ 7,865	$ (2,116)

6. PROPERTY, PLANT AND EQUIPMENT

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

	As of December 31, 2013	As of December 31, 2012
	(In Thousands)	
Electric plant in service	$ 9,753,787	$ 9,389,192
Electric plant acquisition adjustment	802,318	802,318
Accumulated depreciation	(3,971,735)	(3,791,545)
	6,584,370	6,399,965
Construction work in progress	904,586	532,332
Nuclear fuel, net	62,960	81,468
Net property, plant and equipment	$ 7,551,916	$ 7,013,765

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

	As of December 31, 2013	As of December 31, 2012
	(In Thousands)	
Electric plant of VIEs	$ 513,793	$ 543,548
Accumulated depreciation of VIEs	(217,167)	(221,573)
Net property, plant and equipment of VIEs	$ 296,626	$ 321,975

We revised our depreciation rates to reflect changes in the estimated useful lives of some of our assets in 2012. We recorded depreciation expense on property, plant and equipment of $249.9 million in 2013, $247.8 million in 2012 and $262.6 million in 2011. Approximately $9.7 million, $9.8 million and $9.8 million of depreciation expense in 2013, 2012 and 2011, respectively, 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 interests in these facilities as of December 31, 2013, is shown in the table below.

Plant	In-Service Dates	Investment	Accumulated Depreciation	Construction Work in Progress	Net MW	Ownership Percentage
			(Dollars in Thousands)			
La Cygne unit 1 (a)	June 1973	$ 334,054	$ 151,674	$ 280,688	368	50
JEC unit 1 (a)	July 1978	530,407	194,944	166,073	661	92
JEC unit 2 (a)	May 1980	504,508	190,660	13,138	658	92
JEC unit 3 (a)	May 1983	713,937	296,278	1,906	664	92
Wolf Creek (b)	Sept. 1985	1,596,382	773,724	144,083	547	47
State Line (c)	June 2001	110,408	48,357	305	201	40
Total		$ 3,789,696	$ 1,655,637	$ 606,193	3,099	

(a) Jointly owned with KCPL. Our 8% leasehold interest in JEC that is consolidated as a VIE is reflected in the net megawatts (MW) and ownership percentage provided above, but not in the other amounts in the table.
(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 fuel expense for the above plants is generally based on the amount of power we take from the respective 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 MW of net capacity. The VIE's investment in the 50% interest was $392.1 million and accumulated depreciation was $187.4 million as of December 31, 2013. 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

In July 2013 Westar Energy extended the term of its $730.0 million revolving credit facility to terminate in September 2017. As long as there is no default under the facility, Westar Energy may extend the facility up to an additional year and may increase the aggregate amount of borrowings under the facility to $1.0 billion, both subject to lender participation. All borrowings under the facility are secured by KGE first mortgage bonds. As of December 31, 2013, no amounts had been borrowed and $18.4 million of letters of credit had been issued under this revolving credit facility. As of December 31, 2012, none had been borrowed and $13.8 million of letters of credit had been issued under this revolving credit facility.

In 2011, Westar Energy entered into a revolving credit facility with a syndicate of banks for $270.0 million. In February 2014, Westar Energy extended the term of the $270.0 million revolving credit facility to February 2017, provided that $20.0 million of this facility will terminate in February 2016. As long as there is no default under the facility, Westar Energy may increase the aggregate amount of borrowings under the facility to $400.0 million, subject to lender participation. All borrowings under the facility are secured by KGE first mortgage bonds. As of December 31, 2013 and 2012, Westar Energy had no borrowed amounts or letters of credit outstanding under this revolving credit facility.

In 2011, Westar Energy entered into a commercial paper program pursuant to which it may issue commercial paper up to a maximum aggregate amount outstanding at any one time of $1.0 billion. This program is supported by Westar Energy's revolving credit facilities. Maturities of commercial paper issuances may not exceed 365 days from the date of issuance and proceeds from such issuances will be used to temporarily fund capital expenditures, to repay borrowings under Westar Energy's revolving credit facilities, for working capital and/or for other general corporate purposes. Westar Energy had issued $134.6 million and $339.2 million of commercial paper as of December 31, 2013 and 2012, respectively.

In addition, total combined borrowings under Westar Energy's commercial paper program and revolving credit facilities may not exceed $1.0 billion at any given time. The weighted average interest rate on short-term borrowings outstanding as of December 31, 2013 and December 31, 2012, was 0.28% and 0.46%, respectively. Additional information regarding our short-term debt is as follows.

	As of December 31,	
	2013	2012
	(Dollars in Thousands)	
Weighted average short-term debt outstanding during the year	$ 228,352	$ 298,907
Weighted daily average interest rates during the year, excluding fees	0.39%	0.55%

Our interest expense on short-term debt was $2.4 million in 2013, $3.2 million in 2012 and $3.9 million in 2011.

9. LONG-TERM DEBT

Outstanding Debt

The following table summarizes our long-term debt outstanding.

	As of December 31,	
	2013	2012
	(In Thousands)	
Westar Energy		
First mortgage bond series:		
6.00% due 2014	$ 250,000	$ 250,000
5.15% due 2017	125,000	125,000
8.625% due 2018	300,000	300,000
5.10% due 2020	250,000	250,000
5.95% due 2035	125,000	125,000
5.875% due 2036	150,000	150,000
4.125% due 2042	550,000	550,000
4.10% due 2043	250,000	—
4.625% due 2043	250,000	—
	2,250,000	1,750,000
Pollution control bond series:		
Variable due 2032, 0.12% as of December 31, 2013; 0.32% as of December 31, 2012	45,000	45,000
Variable due 2032, 0.12% as of December 31, 2013; 0.26% as of December 31, 2012	30,500	30,500
	75,500	75,500
KGE		
First mortgage bond series:		
6.70% due 2019	300,000	300,000
6.15% due 2023	50,000	50,000
6.53% due 2037	175,000	175,000
6.64% due 2038	100,000	100,000
	625,000	625,000
Pollution control bond series:		
Variable due 2027, 0.10% as of December 31, 2013; 0.26% as of December 31, 2012	21,940	21,940
5.30% due 2031	108,600	108,600
5.30% due 2031	18,900	18,900
4.85% due 2031	50,000	50,000
5.60% due 2031	—	50,000
6.00% due 2031	—	50,000
5.00% due 2031	50,000	50,000
Variable due 2032, 0.10% as of December 31, 2013; 0.26% as of December 31, 2012	14,500	14,500
Variable due 2032, 0.10% as of December 31, 2013; 0.26% as of December 31, 2012	10,000	10,000
	273,940	373,940
Total long-term debt	3,224,440	2,824,440
Unamortized debt discount (a)	(5,482)	(5,169)
Long-term debt due within one year	(250,000)	—
Long-term debt, net	$ 2,968,958	$ 2,819,271
Variable Interest Entities		
6.99% due 2014 (b)	316	866
5.92 % due 2019 (b)	13,243	17,630
5.647% due 2021 (b)	208,123	229,128
Total long-term debt of variable interest entities	221,682	247,624
Unamortized debt premium (a)	599	1,061
Long-term debt of variable interest entities due within one year	(27,479)	(25,942)
Long-term debt of variable interest entities, net	$ 194,802	$ 222,743

(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, 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, 2013, approximately $505.3 million principal amount of additional first mortgage bonds could be issued under the most restrictive provisions in Westar Energy's mortgage. As of December 31, 2013, approximately $1.1 billion principal amount of additional KGE first mortgage bonds could be issued under the most restrictive provisions in KGE's mortgage.

As of December 31, 2013, we had $121.9 million of variable rate, tax-exempt bonds. While the interest rates for these bonds have been extremely low, we continue to monitor the credit markets and evaluate our options with respect to these bonds.

In August 2013, Westar Energy issued $250.0 million principal amount of first mortgage bonds bearing stated interest at 4.625% and maturing September 2043.

In June 2013, KGE redeemed two pollution control bond series with an aggregate principal amount of $100.0 million and stated interest rates at 5.60% and 6.00%.

In March 2013, Westar Energy issued $250.0 million principal amount of first mortgage bonds bearing stated interest at 4.10% and maturing April 2043.

In May 2012, Westar Energy issued $300.0 million principal amount of first mortgage bonds at a discount yielding 4.157%, bearing stated interest at 4.125% and maturing in March 2042. These bonds constitute a further issuance of a series of bonds initially issued in March 2012 in the principal amount of $250.0 million, at a discount yielding 4.13%, bearing stated interest at 4.125% and maturing in March 2042.

In May 2012, Westar Energy redeemed $150.0 million aggregate principal amount of 6.10% first mortgage bonds. Additionally, in March 2012 Westar Energy redeemed $57.2 million aggregate principal amount of 5.00% pollution control bonds and KGE redeemed $13.3 million aggregate principal amount of 5.10% pollution control bonds.

Proceeds from issuances were used to repay short-term debt, which was used to purchase capital equipment, to redeem bonds, and for working capital and general corporate purposes.

Maturities

The principal amounts of our long-term debt maturities as of December 31, 2013, are as follows.

Year	Long-term debt	Long-term debt of VIEs
	(In Thousands)	
2014	$ 250,000	$ 27,479
2015	—	27,933
2016	—	28,309
2017	125,000	26,842
2018	300,000	28,538
Thereafter	2,549,440	82,581
Total maturities	$ 3,224,440	$ 221,682

Interest expense on long-term debt was $154.9 million in 2013, $145.6 million in 2012 and $142.6 million in 2011. Interest expense on long-term debt of VIEs was $13.0 million in 2013, $15.1 million in 2012 and $16.8 million in 2011.

10. TAXES

Income tax expense is comprised of the following components.

	Year Ended December 31,		
	2013	2012	2011
	(In Thousands)		
Income Tax Expense (Benefit):			
Current income taxes:			
Federal	$ 135	$ (691)	$ (8,575)
State	279	579	196
Deferred income taxes:			
Federal	102,030	102,960	93,089
State	24,443	26,300	21,337
Investment tax credit amortization	(3,166)	(3,012)	(2,703)
Income tax expense	$ 123,721	$ 126,136	$ 103,344

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

	As of December 31,	
	2013	2012
	(In Thousands)	
Current deferred tax assets	$ 37,927	$ —
Other current liabilities	—	8,654
Non-current deferred tax liabilities	1,361,418	1,197,837
Net deferred tax liabilities	$ 1,323,491	$ 1,206,491

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,	
	2013	2012
	(In Thousands)	
Deferred tax assets:		
Tax credit carryforward (a)	$ 212,635	$ 199,160
Net operating loss carryforward (b)	110,588	111,869
Deferred employee benefit costs	85,720	191,997
Deferred state income taxes	57,243	55,577
Deferred regulatory gain on sale-leaseback	38,124	40,543
Alternative minimum tax carryforward (c)	35,666	36,471
Deferred compensation	30,022	28,319
Accrued liabilities	17,396	15,969
Disallowed costs	11,453	12,083
LaCygne dismantling cost	8,110	7,156
Capital loss carryforward (d)	3,447	11,509
Other	20,058	13,741
Total gross deferred tax assets	630,462	724,394
Less: Valuation allowance (e)	3,504	13,812
Deferred tax assets	$ 626,958	$ 710,582
Deferred tax liabilities:		
Accelerated depreciation	$ 1,390,669	$ 1,255,892
Acquisition premium	171,907	179,920
Amounts due from customers for future income taxes, net	163,742	169,091
Deferred employee benefit costs	85,720	191,997
Deferred state income taxes	51,504	50,134
Pension expense tracker	21,230	22,437
Storm costs	21,165	4,373
Debt reacquisition costs	19,985	22,313
Other	24,527	20,916
Total deferred tax liabilities	$ 1,950,449	$ 1,917,073
Net deferred tax liabilities	$ 1,323,491	$ 1,206,491

(a) Based on filed tax returns and amounts expected to be reported in current year tax returns (December 31, 2013), we had available federal general business tax credits of $50.2 million and state investment tax credits of $162.4 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 2020 and ending in 2033. The state investment tax credits expire beginning in 2017 and ending in 2029.

(b) As of December 31, 2013, we had a federal net operating loss carryforward of $277.6 million, which is available to offset federal taxable income. The net operating losses will expire beginning in 2031 and ending in 2032.

(c) As of December 31, 2013, we had available an alternative minimum tax credit carryforward of $35.7 million, which has an unlimited carryforward period.

(d) As of December 31, 2013, we had an unused capital loss carryforward of $8.7 million that is available to offset future capital gains. The capital losses will expire in 2016.

(e) As we do not expect to realize any significant capital gains in the future, we have established a valuation allowance of $3.5 million. The total valuation allowance related to the deferred tax assets was $3.5 million as of December 31, 2013, and $13.8 million as of December 31, 2012.

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.

	Year Ended December 31,		
	2013	2012	2011
Statutory federal income tax rate	35.0 %	35.0 %	35.0 %
Effect of:			
Corporate-owned life insurance policies	(5.4)	(4.9)	(4.5)
State income taxes	3.8	4.3	4.1
Production tax credits	(2.3)	(2.4)	(2.9)
Flow through depreciation for plant-related differences	2.2	1.4	1.8
AFUDC equity	(1.2)	(1.0)	(0.6)
Capital loss utilization carryforward	(1.1)	(0.3)	(0.5)
Amortization of federal investment tax credits	(0.7)	(0.7)	(0.8)
Liability for unrecognized income tax benefits	0.1	0.2	—
Other	(1.3)	(0.7)	(1.2)
Effective income tax rate	29.1 %	30.9 %	30.4 %

We file income tax returns in the U.S. federal jurisdiction as well as 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 2008 and forward.

The IRS has examined our federal income tax return filed for tax year 2010 and the amended federal income tax returns we filed for tax years 2007, 2008 and 2009. The examination results, which were approved by the Joint Committee on Taxation of the U.S. Congress and accepted by the IRS in April 2013, did not have a significant impact on our consolidated statements of income or cash flows.

On September 13, 2013, the IRS and United States Treasury Department released final regulations regarding the deduction and capitalization of expenditures related to tangible property, including the tax treatment of, among other things, materials and supplies and the determination of whether expenditures with respect to tangible property are a deductible repair or must be capitalized, and re-proposed regulations regarding dispositions of property under the Modified Accelerated Cost Recovery System. The regulations are generally effective for tax years beginning on or after January 1, 2014, but may be adopted in earlier years under certain circumstances. On January 24, 2014, the IRS issued transition guidance that provides the procedures for taxpayers to change their method of accounting to comply with the regulations. We intend to adopt the guidance effective January 1, 2014. We do not expect the adoption of the regulations to have a material impact on our consolidated financial statements.

The liability for unrecognized income tax benefits increased from $1.2 million at December 31, 2012, to $1.7 million at December 31, 2013. The net increase in the liability for unrecognized income tax benefits was largely attributable to tax positions taken with respect to the capitalization of plant related expenditures. 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 amounts of unrecognized income tax benefits is as follows:

	2013	2012	2011
		(In Thousands)	
Liability for unrecognized income tax benefits as of January 1	$ 1,219	$ 2,483	$ 1,888
Additions based on tax positions related to the current year	224	373	967
Additions for tax positions of prior years	325	—	939
Reductions for tax positions of prior years	(65)	(1,637)	(563)
Settlements	—	—	(748)
Liability for unrecognized income tax benefits as of December 31	$ 1,703	$ 1,219	$ 2,483

The liability for unrecognized income tax benefits, as disclosed above, is net of reductions to deferred tax assets for credit carryforwards of $0.3 million and $0.2 million as of December 31, 2012 and 2011, respectively. There were no reductions to deferred tax assets for credit carryforwards as of December 31, 2013. The amounts of unrecognized income tax benefits that, if recognized, would favorably impact our effective income tax rate, were $2.4 million, $2.0 million and $1.2 million (net of tax) as of December 31, 2013, 2012 and 2011, respectively.

Interest related to income tax uncertainties is classified as interest expense and accrued interest liability. During 2013 and 2012 , we did not reverse any interest expense previously recorded for income tax uncertainties. During 2011, we reversed interest expense previously recorded for income tax uncertainties of $0.2 million. As of December 31, 2013 and 2012, we had $0.2 million accrued for interest on our liability related to unrecognized income tax benefits. We accrued no penalties at either December 31, 2013 or 2012.

As of December 31, 2013 and 2012, we had recorded $1.5 million for probable assessments of taxes other than income taxes.

In July 2013, the FASB issued new accounting guidance on presenting an unrecognized tax benefit when a net operating loss carryforward exists. An unrecognized tax benefit should be presented in the financial statements as a reduction to a deferred tax asset for a net operating loss carryforward, similar tax loss, or a tax credit carryforward. To the extent a net operating loss carryforward is not available to settle any additional income taxes that would result from the disallowance of a tax position at the reporting date; the unrecognized tax benefit should be presented in the financial statements as a liability and should not be combined with deferred tax assets. The guidance is effective for fiscal years beginning after December 15, 2013. This guidance is not expected to have a material impact on our consolidated financial results.

11. EMPLOYEE BENEFIT PLANS

Pension and 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, and union employees hired after December 31, 2011, 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 retired executive officers. We have discontinued accruing any future benefits under this non-qualified plan.

The amount we contribute to our pension plan for future periods is not yet known, however, we expect to fund our pension plan each year at least to a level equal to 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.

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 expect to fund our post-retirement plan each year at least to a level equal to current year post-retirement expense.

As a co-owner of Wolf Creek, KGE is indirectly responsible for 47% of the liabilities and expenses associated with the Wolf Creek pension and post-retirement 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 post-retirement benefit plans.

	Pension Benefits		Post-retirement Benefits	
As of December 31,	2013	2012	2013	2012
	(In Thousands)			
Change in Benefit Obligation:				
Benefit obligation, beginning of year	$ 928,708	$ 876,308	$ 152,564	$ 150,078
Service cost	21,420	19,556	2,028	2,057
Interest cost	38,520	39,576	6,007	6,298
Plan participants' contributions	—	—	2,961	2,987
Benefits paid (a)	(36,529)	(60,229)	(10,968)	(9,799)
Actuarial (gains) losses	(128,339)	53,497	(19,531)	943
Benefit obligation, end of year (b)	$ 823,780	$ 928,708	$ 133,061	$ 152,564
Change in Plan Assets:				
Fair value of plan assets, beginning of year	$ 547,931	$ 481,077	$ 106,793	$ 91,858
Actual return on plan assets	68,151	67,328	17,361	10,673
Employer contributions	27,500	56,700	5,318	10,803
Plan participants' contributions	—	—	2,830	2,845
Benefits paid (a)	(33,765)	(57,174)	(10,536)	(9,386)
Fair value of plan assets, end of year	$ 609,817	$ 547,931	$ 121,766	$ 106,793
Funded status, end of year	$ (213,963)	$ (380,777)	$ (11,295)	$ (45,771)
Amounts Recognized in the Balance Sheets Consist of:				
Current liability	$ (2,740)	$ (2,870)	$ (242)	$ (298)
Noncurrent liability	(211,223)	(377,907)	(11,053)	(45,473)
Net amount recognized	$ (213,963)	$ (380,777)	$ (11,295)	$ (45,771)
Amounts Recognized in Regulatory Assets Consist of:				
Net actuarial loss	$ 186,365	$ 383,365	$ (18,890)	$ 12,436
Prior service cost	3,393	3,994	13,942	16,467
Transition obligation	—	—	—	325
Net amount recognized	$ 189,758	$ 387,359	$ (4,948)	$ 29,228

(a) In 2012 certain former employees received a one-time lump sum payment of their pension benefits totaling $26.1 million.

(b) As of December 31, 2013 and 2012, pension benefits include non-qualified benefit obligations of $27.0 million and $30.0 million, respectively, which are funded by a trust containing assets of $34.9 million and $43.5 million, respectively, classified as trading securities. The assets in the aforementioned trust are not included in the table above. See Notes 4 and 5, "Financial Instruments and Trading Securities" and "Financial Investments," respectively, for additional information regarding these amounts.

As of December 31,	Pension Benefits 2013	Pension Benefits 2012	Post-retirement Benefits 2013	Post-retirement Benefits 2012
	(Dollars in Thousands)			
Pension Plans With a Projected Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$ 823,780	$ 928,708	$ —	$ —
Fair value of plan assets	609,817	547,931	—	—
Pension Plans With an Accumulated Benefit Obligation In Excess of Plan Assets:				
Accumulated benefit obligation	$ 732,150	$ 806,888	—	—
Fair value of plan assets	609,817	547,931	—	—
Post-retirement Plans With an Accumulated Post-retirement Benefit Obligation In Excess of Plan Assets:				
Accumulated post-retirement benefit obligation	—	—	$ 133,061	$ 152,564
Fair value of plan assets	—	—	121,766	106,793
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Benefit Obligation:				
Discount rate	5.07%	4.13%	4.88%	3.99%
Compensation rate increase	4.00%	4.00%	—	—

We use a measurement date of December 31 for our pension and post-retirement benefit plans. The discount rate used to determine the current year pension obligation and the following year's pension expense is based on a bond selection-settlement portfolio approach. This approach develops a discount rate by selecting a portfolio of high quality, non-callable corporate bonds that generate sufficient cash flow to provide for the projected benefit payments of the plan. After the bond portfolio is selected, a single interest rate is determined that equates the present value of the plan's projected benefit payments discounted at this rate with the market value of the bonds selected.

We amortize prior service cost 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 gain or 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. The KCC allows us to record 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. We accumulate such regulatory asset or liability between general rate reviews and amortize the accumulated amount as part of resetting our base prices. Following is additional information regarding our pension and post-retirement benefit plans.

	Pension Benefits			Post-retirement Benefits		
Year Ended December 31,	2013	2012	2011	2013	2012	2011
			(Dollars in Thousands)			
Components of Net Periodic Cost (Benefit):						
Service cost	$ 21,420	$ 19,556	$ 16,076	$ 2,028	$ 2,057	$ 1,803
Interest cost	38,520	39,576	40,045	6,007	6,298	6,793
Expected return on plan assets	(33,405)	(32,283)	(31,087)	(6,691)	(5,491)	(5,002)
Amortization of unrecognized:						
Transition obligation, net	—	—	—	325	3,912	3,911
Prior service costs	601	612	1,213	2,524	2,524	2,524
Actuarial loss, net	33,914	32,778	23,659	1,125	1,503	702
Net periodic cost before regulatory adjustment	61,050	60,239	49,906	5,318	10,803	10,731
Regulatory adjustment (a)	3,693	(6,523)	(22,098)	2,922	23	1,344
Net periodic cost	$ 64,743	$ 53,716	$ 27,808	$ 8,240	$ 10,826	$ 12,075
Other Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets:						
Current year actuarial (gain)/loss	$ (163,086)	$ 18,451	$ 97,429	$ (30,201)	$ (4,239)	$ 10,421
Amortization of actuarial (loss)	(33,914)	(32,778)	(23,659)	(1,125)	(1,503)	(702)
Current year prior service cost	—	—	—	—	—	4,451
Amortization of prior service costs	(601)	(612)	(1,213)	(2,525)	(2,524)	(2,524)
Amortization of transition obligation	—	—	—	(325)	(3,912)	(3,911)
Total recognized in regulatory assets	$ (197,601)	$ (14,939)	$ 72,557	$ (34,176)	$ (12,178)	$ 7,735
Total recognized in net periodic cost and regulatory assets	$ (132,858)	$ 38,777	$ 100,365	$ (25,936)	$ (1,352)	$ 19,810
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost (Benefit):						
Discount rate	4.13%	4.50%	5.35%	3.99%	4.25%	5.00%
Expected long-term return on plan assets	6.50%	6.50%	6.50%	6.00%	6.00%	6.00%
Compensation rate increase	4.00%	4.00%	4.00%	4.00%	—	—

(a) The regulatory adjustment represents the difference between current period pension or post-retirement benefit expense and the amount of such expense recognized in setting our prices.

We estimate that we will amortize the following amounts from regulatory assets into net periodic cost in 2014.

	Pension Benefits	Post-retirement Benefits
	(In Thousands)	
Actuarial loss (gain)	$ 19,362	$ (742)
Prior service cost	525	2,524
Total	$ 19,887	$ 1,782

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.

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

	As of December 31,	
	2013	2012
Health care cost trend rate assumed for next year	7.5%	8.0%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	5.0%	5.0%
Year that the rate reaches the ultimate trend rate	2019	2019

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	$ 153	$ (136)
Effect on post-retirement benefit obligation	2,098	(1,901)

Plan Assets

We manage pension and post-retirement benefit plan assets in a prudent manner with regard to preserving principal while providing reasonable returns. We have adopted a long-term investment horizon such that the chances and duration of investment losses are carefully weighed against the long-term potential for appreciation of assets. Part of our strategy includes managing interest rate sensitivity of plan assets relative to the associated liabilities. The primary objective of the pension plan is to provide a source of retirement income for its participants and beneficiaries, and the primary financial objective of the plan is to improve its funded status. The primary objective of the post-retirement benefit plan is growth in assets and preservation of principal, while minimizing interim volatility, to meet anticipated claims of plan participants. We delegate the management of our pension and post-retirement benefit plan assets to independent investment advisors who hire and dismiss investment managers based upon various factors. The investment advisors strive to diversify investments across asset classes, sectors and manager styles to minimize the risk of large losses, based upon objectives and risk tolerance specified by management, which include allowable and/or prohibited investment types. We measure and monitor investment risk on an ongoing basis through quarterly investment portfolio reviews and annual liability measurements.

As noted above, we have established certain prohibited investments for our pension and post-retirement benefit plans. Such 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, to reduce concentration of risk, the pension plan will not invest in any fund that holds more than 25% of its total assets to be invested in the securities of one or more issuers conducting their principal business activities in the same industry. This restriction does not apply to investments in securities issued or guaranteed by the U.S. government or its agencies.

Target allocations for our pension plan assets are about 39% to debt securities, 39% to equity securities, 12% alternative investments such as real estate securities, hedge funds and private equity investments, and the remaining 10% to a fund which provides tactical portfolio overlay by investing in debt and equity securities. Our investments in equity include investment funds with underlying investments in domestic and foreign large-, mid- and small-cap companies, derivatives related to such holdings, private equity investments including late-stage venture investments and other investments. Our investments in debt 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 consist primarily of funds invested in core real estate throughout the U.S. while alternative funds invest in wide ranging investments including equity and debt securities of domestic and foreign corporations, debt securities issued by U.S. and foreign governments and their agencies, structured debt, warrants, exchange-traded funds, derivative instruments, private investment funds and other investments.

Target allocations for our post-retirement benefit plan assets are 65% to equity securities and 35% to debt securities. Our investments in equity securities include investment funds with underlying investments primarily 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 domestic and foreign corporate entities, obligations of U.S. and foreign governments and their agencies, private placement securities and other investments.

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 post-retirement benefit plan assets at fair value. From time to time, the pension and post-retirement benefits trusts may buy and sell investments resulting in changes within the hierarchy. See Note 4, "Financial Instruments and Trading Securities," for a description of the hierarchal framework.

All level 2 pension investments are held in investment funds that are measured at fair value using daily net asset values as reported by the trustee, except for $47.4 million as of December 31, 2013, invested directly in long-term U.S. Treasury securities. We also maintain certain level 3 investments in private equity, alternative investments and real estate securities that are also measured at fair value using net asset value, but require significant unobservable market information to measure the fair value of the underlying investments. The underlying investments in private equity are measured at fair value utilizing both market- and income-based models, public company comparables, investment cost or 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. The underlying alternative investments include collateralized debt obligations, mezzanine debt and a variety of other investments. The fair value of these investments is measured using a variety of primarily market-based models utilizing inputs such as security prices, maturity, call features, ratings and other developments related to specific securities. The underlying real estate investments 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.

The following table provides the fair value of our pension plan assets and the corresponding level of hierarchy as of December 31, 2013 and 2012.

As of December 31, 2013	Level 1	Level 2	Level 3	Total
	(In Thousands)			
Assets:				
Domestic equity	$ —	$ 161,272	$ 22,488	$ 183,760
International equity	—	75,872	—	75,872
Core bonds	—	191,506	—	191,506
High-yield bonds	—	20,796	—	20,796
Emerging market bonds	—	13,113	—	13,113
Combination debt/equity fund	—	58,336	—	58,336
Alternative investments	—	—	39,171	39,171
Real estate securities	—	—	24,022	24,022
Cash equivalents	—	3,241	—	3,241
Total Assets Measured at Fair Value	$ —	$ 524,136	$ 85,681	$ 609,817

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Assets:				
Domestic equity	$ —	$ 129,501	$ 18,493	$ 147,994
International equity	—	67,743	—	67,743
Core bonds	—	178,784	—	178,784
High-yield bonds	—	19,070	—	19,070
Emerging market bonds	—	14,276	—	14,276
Combination debt/equity fund	—	50,750	—	50,750
Alternative investments	—	—	45,535	45,535
Real estate securities	—	—	20,927	20,927
Cash equivalents	—	2,852	—	2,852
Total Assets Measured at Fair Value	$ —	$ 462,976	$ 84,955	$ 547,931

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, 2013 and 2012.

	Domestic Equity	Alternative Funds	Real Estate Securities	Total
	(In Thousands)			
Balance as of December 31, 2012	$ 18,493	$ 45,535	$ 20,927	$ 84,955
Actual gain (loss) on plan assets:				
Relating to assets still held at the reporting date	3,845	1,936	3,307	9,088
Relating to assets sold during the period	—	826	—	826
Purchases, issuances and settlements, net	150	(9,126)	(212)	(9,188)
Balance as of December 31, 2013	$ 22,488	$ 39,171	$ 24,022	$ 85,681
Balance as of December 31, 2011	$ 15,375	$ 40,716	$ 18,848	$ 74,939
Actual gain (loss) on plan assets:				
Relating to assets still held at the reporting date	(25)	4,819	2,296	7,090
Relating to assets sold during the period	53	—	(27)	26
Purchases, issuances and settlements, net	3,090	—	(190)	2,900
Balance as of December 31, 2012	$ 18,493	$ 45,535	$ 20,927	$ 84,955

The following table provides the fair value of our post-retirement benefit plan assets and the corresponding level of hierarchy as of December 31, 2013 and 2012.

As of December 31, 2013	Level 1	Level 2	Level 3	Total
	(In Thousands)			
Assets:				
Domestic equity	$ —	$ 64,080	$ —	$ 64,080
International equity	—	16,018	—	16,018
Core bonds	—	41,092	—	41,092
Cash equivalents	—	576	—	576
Total Assets Measured at Fair Value	$ —	$ 121,766	$ —	$ 121,766
As of December 31, 2012				
Assets:				
Domestic equity	$ —	$ 55,441	$ —	$ 55,441
International equity	—	14,037	—	14,037
Core bonds	—	36,738	—	36,738
Cash equivalents	—	577	—	577
Total Assets Measured at Fair Value	$ —	$ 106,793	$ —	$ 106,793

Cash Flows

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

Expected Cash Flows	Pension Benefits		Post-retirement Benefits	
	To/(From) Trust	(From) Company Assets	To/(From) Trust	(From) Company Assets
	(In Millions)			
Expected contributions:				
2014	$ 30.8		$ 2.9	
Expected benefit payments:				
2014	$ (35.4)	$ (2.8)	$ (8.7)	$ (0.2)
2015	(36.9)	(2.8)	(9.1)	(0.2)
2016	(39.2)	(2.8)	(9.3)	(0.2)
2017	(41.5)	(2.7)	(9.6)	(0.2)
2018	(44.5)	(2.7)	(9.8)	(0.2)
2019 - 2023	(257.9)	(12.8)	(49.7)	(1.0)

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 plan 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 $6.9 million in 2013, $7.1 million in 2012 and $7.0 million in 2011.

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. In May 2011, Westar Energy shareholders approved an increase in the number of shares of common stock that may be granted under the LTISA Plan to 8.25 million shares from 5.0 million shares. As of December 31, 2013, awards of approximately 4.9 million 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,		
	2013	2012	2011
	(In Thousands)		
Compensation expense	$ 8,121	$ 7,203	$ 8,367
Income tax benefits related to stock-based compensation arrangements	3,212	2,849	3,309

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. In 2011, outstanding RSUs with only service requirements previously awarded to our former chief executive officer that were subject to forfeiture were modified to provide for the vesting upon his retirement in July 2011 of a prorated number of the RSUs based on the number of days from the grant date of the RSUs to his retirement date. In addition, outstanding RSUs with performance measures previously awarded to our former chief executive officer were modified to provide for the vesting on the scheduled vesting date, subject to the satisfaction of the applicable performance criteria, of a prorated number of the target RSUs based on the number of days from the grant date of the RSUs to his retirement date. We recorded compensation expense of $2.8 million in 2011 related to these modifications.

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 grant date. 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 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 2013 valuation, inputs for expected volatility ranged from 15.0% to 23.5% and the risk-free interest rate was approximately 0.3%. For the 2012 valuation, inputs for expected volatility ranged from 17.6% to 33.6% and the risk-free interest rate was approximately 0.4%. 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, 2013, 2012 and 2011, our RSU activity for awards with only service requirements was as follows:

	As of December 31,					
	2013		2012		2011	
	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	351.1	$ 25.47	368.5	$ 23.83	600.4	$ 21.50
Granted	139.6	31.06	131.0	27.82	284.1	26.30
Vested	(125.5)	23.22	(127.8)	23.34	(187.3)	23.50
Forfeited	(12.7)	28.35	(20.6)	24.40	(328.7)	24.37
Nonvested balance, end of year	352.5	28.38	351.1	25.47	368.5	23.83

Total unrecognized compensation cost related to RSU awards with only service requirements was $4.4 million as of December 31, 2013. We expect to recognize these costs over a remaining weighted-average period of 1.7 years. The total fair value of RSUs with only service requirements that vested during the years ended December 31, 2013, 2012 and 2011, was $3.7 million, $3.7 million and $4.8 million, respectively.

During the years ended December 31, 2013, 2012 and 2011, our RSU activity for awards with performance measures was as follows:

	As of December 31,					
	2013		2012		2011	
	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	340.1	$ 29.20	324.2	$ 28.31	348.4	$ 24.98
Granted	134.4	31.54	122.3	28.84	244.4	31.26
Vested	(112.5)	28.29	(88.2)	25.46	(119.5)	24.12
Forfeited	(11.9)	30.45	(18.2)	29.00	(149.1)	28.72
Nonvested balance, end of year	350.1	30.35	340.1	29.20	324.2	28.31

As of December 31, 2013 and 2012, total unrecognized compensation cost related to RSU awards with performance measures was $4.0 million and $3.5 million, respectively. We expect to recognize these costs over a remaining weighted-average period of 1.7 years. The total fair value of RSUs with performance measures that vested during the years ended December 31, 2013, 2012 and 2011, was $2.3 million, $3.6 million and $3.6 million, respectively.

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 551 shares of common stock for dividends in 2013, 666 shares in 2012 and 4,757 shares in 2011. Participants received common stock distributions of 3,456 shares in 2013, 1,461 shares in 2012 and 67,426 shares in 2011.

Income tax benefits resulting from 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.

12. WOLF CREEK EMPLOYEE BENEFIT PLANS

Pension and 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 post-retirement benefit plans. KGE accrues its 47% share of Wolf Creek's cost of pension and post-retirement benefits during the years an employee provides service. The following tables summarize the status of KGE's 47% share of the Wolf Creek pension and post-retirement benefit plans.

	Pension Benefits		Post-retirement Benefits	
As of December 31,	2013	2012	2013	2012
	(In Thousands)			
Change in Benefit Obligation:				
Benefit obligation, beginning of year	$ 176,891	$ 161,396	$ 11,020	$ 10,129
Service cost	6,835	6,062	206	191
Interest cost	7,562	7,537	413	411
Plan participants’ contributions	—	—	696	608
Benefits paid (a)	(4,349)	(8,569)	(1,022)	(988)
Actuarial (gains) losses	(24,119)	9,815	(1,303)	669
Amendments	—	650	—	—
Benefit obligation, end of year	$ 162,820	$ 176,891	$ 10,010	$ 11,020
Change in Plan Assets:				
Fair value of plan assets, beginning of year	$ 98,051	$ 80,727	$ 13	$ 4
Actual return on plan assets	13,166	11,764	—	—
Employer contributions	7,624	13,887	330	389
Plan participants' contributions	—	—	696	608
Benefits paid	(4,107)	(8,327)	(1,022)	(988)
Fair value of plan assets, end of year	$ 114,734	$ 98,051	$ 17	$ 13
Funded status, end of year	$ (48,086)	$ (78,840)	$ (9,993)	$ (11,007)
Amounts Recognized in the Balance Sheets Consist of:				
Current liability	$ (237)	$ (243)	$ (614)	$ (625)
Noncurrent liability	(47,849)	(78,597)	(9,379)	(10,382)
Net amount recognized	$ (48,086)	$ (78,840)	$ (9,993)	$ (11,007)
Amounts Recognized in Regulatory Assets Consist of:				
Net actuarial loss	$ 29,203	$ 64,535	$ 2,076	$ 3,643
Prior service cost	617	675	—	—
Transition obligation	—	—	—	1
Net amount recognized	$ 29,820	$ 65,210	$ 2,076	$ 3,644

(a) In 2012 certain former employees received a one-time lump sum payment of their pension benefits. Our share of the payment totaled $4.9 million.

	Pension Benefits		Post-retirement Benefits	
As of December 31,	2013	2012	2013	2012
	(Dollars in Thousands)			
Pension Plans With a Projected Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$ 162,820	$ 176,891	$ —	$ —
Fair value of plan assets	114,734	98,051	—	—
Pension Plans With an Accumulated Benefit Obligation In Excess of Plan Assets:				
Accumulated benefit obligation	$ 137,459	$ 141,722	$ —	$ —
Fair value of plan assets	114,734	98,051	—	—
Post-retirement Plans With an Accumulated Post-retirement Benefit Obligation In Excess of Plan Assets:				
Accumulated post-retirement benefit obligation	$ —	$ —	$ 10,010	$ 11,020
Fair value of plan assets	—	—	16	13
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Benefit Obligation:				
Discount rate	5.11%	4.16%	4.70%	3.78%
Compensation rate increase	4.00%	4.00%	—	—

Wolf Creek uses a measurement date of December 31 for its pension and post-retirement benefit plans. The discount rate used to determine the current year pension obligation and the following year's pension expense is based on a bond selection-settlement portfolio approach. This approach develops a discount rate by selecting a portfolio of high quality, non-callable corporate bonds that generate sufficient cash flow to provide for the projected benefit payments of the plan. After the bond portfolio is selected, a single interest rate is determined that equates the present value of the plan's projected benefit payments discounted at this rate with the market value of the bonds selected.

The prior service cost (benefit) is amortized on a straight-line basis over the average future service of the active employees (plan participants) benefiting under the plan at the time of the amendment. The net actuarial gain or loss 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. Following is additional information regarding KGE's 47% share of the Wolf Creek pension and other post-retirement benefit plans.

	Pension Benefits			Post-retirement Benefits		
Year Ended December 31,	2013	2012	2011	2013	2012	2011
	(Dollars in Thousands)					
Components of Net Periodic Cost (Benefit):						
Service cost	$ 6,835	$ 6,062	$ 4,957	$ 206	$ 191	$ 165
Interest cost	7,562	7,537	7,370	413	411	458
Expected return on plan assets	(7,373)	(6,577)	(5,904)	—	—	—
Amortization of unrecognized:						
Transition obligation, net	—	—	52	—	57	58
Prior service costs	58	6	16	—	—	—
Actuarial loss, net	5,421	5,366	3,586	265	234	227
Net periodic cost before regulatory adjustment	12,503	12,394	10,077	884	893	908
Regulatory adjustment (a)	(641)	(1,776)	(2,546)	—	—	—
Net periodic cost	$ 11,862	$ 10,618	$ 7,531	$ 884	$ 893	$ 908
Other Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets:						
Current year actuarial (gain)/loss	$ (29,911)	$ 4,629	$ 29,124	$ (1,303)	$ 669	$ (360)
Amortization of actuarial loss	(5,421)	(5,366)	(3,586)	(265)	(234)	(227)
Current year prior service cost	—	650	—	—	—	—
Amortization of prior service cost	(58)	(6)	(16)	—	—	—
Amortization of transition obligation	—	—	(52)	—	(57)	(58)
Total recognized in regulatory assets	$ (35,390)	$ (93)	$ 25,470	$ (1,568)	$ 378	$ (645)
Total recognized in net periodic cost and regulatory assets	$ (23,528)	$ 10,525	$ 33,001	$ (684)	$ 1,271	$ 263
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost:						
Discount rate	4.16%	4.55%	5.45%	3.78%	4.10%	4.90%
Expected long-term return on plan assets	7.50%	7.50%	7.50%	—	—	—
Compensation rate increase	4.00%	4.00%	4.00%	—	—	—

(a) The regulatory adjustment represents the difference between current period pension or post-retirement benefit expense and the amount of such expense recognized in setting our prices.

We estimate that we will amortize the following amounts from regulatory assets into net periodic cost in 2014.

	Pension Benefits	Post-retirement Benefits
	(In Thousands)	
Actuarial loss	$ 2,987	$ 165
Prior service cost	58	—
Total	$ 3,045	$ 165

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

	As of December 31,	
	2013	2012
Health care cost trend rate assumed for next year	7.5%	8.0%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	5.0%	5.0%
Year that the rate reaches the ultimate trend rate	2019	2019

The health care cost trend rate affects the projected benefit obligation. A 1% change in assumed health care cost growth rates would have effects shown in the following table.

	One-Percentage-Point Increase	One-Percentage-Point Decrease
	(In Thousands)	
Effect on total of service and interest cost	$ (9)	$ 9
Effect on post-retirement benefit obligation	(102)	97

Plan Assets

Its pension and post-retirement plan investment strategy is to manage assets in a prudent manner with regard to preserving principal while providing reasonable returns. It has adopted a long-term investment horizon such that the chances and duration of investment losses are carefully weighed against the long-term potential for appreciation of assets. Part of its strategy includes managing interest rate sensitivity of plan assets relative to the associated liabilities. The primary objective of the pension plan is to provide a source of retirement income for its participants and beneficiaries, and the primary financial objective of the plan is to improve its funded status. The primary objective of the post-retirement benefit plan is growth in assets and preservation of principal, while minimizing interim volatility, to meet anticipated claims of plan participants. Wolf Creek delegates the management of its pension and post-retirement benefit plan assets to independent investment advisors who hire and dismiss investment managers based upon various factors. The investment advisors strive to diversify investments across asset classes, sectors and manager styles to minimize the risk of large losses, based upon objectives and risk tolerance specified by Wolf Creek, which include allowable and/or prohibited investment types. It measures and monitors investment risk on an ongoing basis through quarterly investment portfolio reviews and annual liability measurements.

The target allocations for Wolf Creek's pension plan assets are 31% to international equity securities, 25% to domestic equity securities, 25% to debt securities, 10% to real estate securities, 5% to commodity investments and 4% to other investments. The investments in both international and domestic equity 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 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.

All of Wolf Creek's pension plan assets are recorded at fair value using daily net asset values as reported by the trustee. However, level 3 investments in real estate funds and alternative funds are invested in underlying investments that are illiquid and require significant judgment when measuring them at fair value using market- and income-based models. Significant unobservable inputs for underlying real estate investments include estimated market discount rates, projected cash flows and estimated value into perpetuity. Alternative funds invest in a wide range of investments typically with low correlations to traditional investments.

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 post-retirement benefit plan assets at fair value. From time to time, the Wolf Creek pension trust may buy and sell investments resulting in changes within the hierarchy. See Note 4, "Financial Instruments and Trading Securities," 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, 2013 and 2012.

As of December 31, 2013	Level 1	Level 2	Level 3	Total
	(In Thousands)			
Assets:				
Domestic equity	$ —	$ 30,599	$ —	$ 30,599
International equity	—	36,868	—	36,868
Core bonds	—	26,926	—	26,926
Real estate securities	—	5,440	5,094	10,534
Commodities	—	5,245	—	5,245
Alternative investments	—	—	4,147	4,147
Cash equivalents	—	415	—	415
Total Assets Measured at Fair Value	$ —	$ 105,493	$ 9,241	$ 114,734
As of December 31, 2012				
Assets:				
Domestic equity	$ —	$ 24,305	$ —	$ 24,305
International equity	—	30,484	—	30,484
Core bonds	—	24,763	—	24,763
Real estate securities	—	4,972	4,541	9,513
Commodities	—	4,789	—	4,789
Alternative investments	—	—	3,900	3,900
Cash equivalents	—	297	—	297
Total Assets Measured at Fair Value	$ —	$ 89,610	$ 8,441	$ 98,051

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, 2013 and 2012.

	Real Estate Securities	Alternative Investments	Total
	(In Thousands)		
Balance as of December 31, 2012	$ 4,541	$ 3,900	$ 8,441
Actual gain (loss) on plan assets:			
Relating to assets still held at the reporting date	553	247	800
Balance as of December 31, 2013	$ 5,094	$ 4,147	$ 9,241
Balance as of December 31, 2011	$ 3,630	$ —	$ 3,630
Actual gain (loss) on plan assets:			
Relating to assets still held at the reporting date	(411)	23	(388)
Relating to assets sold during the period	755	—	755
Purchases, issuances and settlements, net	567	3,877	4,444
Balance as of December 31, 2012	$ 4,541	$ 3,900	$ 8,441

Cash Flows

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

Expected Cash Flows	Pension Benefits		Post-retirement Benefits	
	To/(From) Trust	(From) Company Assets	To/(From) Trust	(From) Company Assets
	(In Millions)			
Expected contributions:				
2014	$ 5.4		$ 0.6	
Expected benefit payments:				
2014	$ (4.6)	$ (0.2)	$ (0.6)	$ —
2015	(5.3)	(0.2)	(0.7)	—
2016	(6.1)	(0.2)	(0.8)	—
2017	(7.0)	(0.2)	(0.8)	—
2018	(7.8)	(0.2)	(0.8)	—
2019 - 2022	(53.0)	(1.3)	(4.4)	—

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 $1.4 million in 2013, $1.3 million in 2012 and $1.3 million in 2011.

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 and transmission, which are discussed below under "—Fuel, Purchased Power and Transmission Commitments." These commitments relate to purchase obligations issued and outstanding at year-end.

The yearly detail of the aggregate amount of required payments as of December 31, 2013, was as follows.

	Committed Amount
	(In Thousands)
2014	$ 258,293
2015	20,653
2016	25,762
Thereafter	7,463
Total amount committed	$ 312,171

Federal Clean Air Act

We must comply with the federal Clean Air Act, state laws and implementing federal and state regulations that impose, among other things, limitations on emissions generated from our operations, including sulfur dioxide (SO_2), particulate matter (PM), nitrogen oxides (NOx), carbon monoxide (CO), mercury and acid gases.

Emissions from our generating facilities, including PM, 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) and Environmental Protection Agency (EPA), we are required to install, operate and maintain controls to reduce emissions found to cause or contribute to regional haze.

Under the federal Clean Air Act, the EPA sets National Ambient Air Quality Standards (NAAQS) for certain emissions considered harmful to public health and the environment, including two classes of PM, NOx (a precursor to ozone), CO and SO_2, which result from fossil fuel combustion. Areas meeting the NAAQS are designated attainment areas while those that do not meet the NAAQS are considered nonattainment areas. 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. KDHE proposed to designate portions of the Kansas City area nonattainment for the eight-hour ozone standard, which has the potential to impact our operations. The EPA has not acted on KDHE's proposed designation of the Kansas City area and it is uncertain when, or if, such a designation might occur. The Wichita area also exceeded the eight-hour ozone standard and could be designated nonattainment in the future potentially impacting our operations.

In December 2012, the EPA strengthened an existing NAAQS for one class of PM. By the end of 2014, the EPA anticipates making final attainment/nonattainment designations under this rule and expects to issue a final implementation rule. We are currently evaluating the rule and the impact it may have on our operations or consolidated financial results.

In 2010, the EPA strengthened the NAAQS for both NOx and SO_2. We continue to communicate with our regulators regarding these standards and 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 and operating 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 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.

In comparison to a general rate review, the ECRR reduces the amount of time it takes to begin collecting in retail prices the costs associated with capital expenditures for qualifying environmental improvements. We are not allowed to use the ECRR to collect approximately $610.0 million of the projected capital investment associated with the environmental upgrades at La Cygne. In November 2013, the KCC issued an order allowing us to adjust our prices to include the additional investment in the La Cygne environmental upgrades and to reflect cost reductions elsewhere. The new prices are expected to increase our annual retail revenues by approximately $30.7 million. For additional information regarding our abbreviated rate review, see Note 3, "Rate Matters and Regulation." To change our prices to collect increased operating and maintenance costs, we must file a general rate review with the KCC.

Air Emissions

The operation of power plants results in emissions of mercury, acid gases and other air toxics. In 2012, the EPA's Mercury and Air Toxics Standards (MATS) for power plants became effective, replacing the prior federal Clean Air Mercury Rule (CAMR) and requiring significant reductions in mercury, acid gases and other emissions. We expect to be compliant with the new standards by April 2016 as approved by KDHE. We continue to evaluate the new standards and believe that our related investment will be approximately $17.0 million.

Greenhouse Gases

Under regulations known as the Tailoring Rule, the EPA is regulating greenhouse gas (GHG) emissions from certain stationary sources. The regulations are being implemented pursuant to two federal Clean Air Act programs which impose recordkeeping and monitoring requirements and also mandate the implementation of best available control technology (BACT) for projects that cause a significant increase in GHG emissions (defined to be more than 75,000 tons or more per year or 100,000 tons or more per year, depending on various factors). 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 regulations on our operations and consolidated financial results, but we believe the cost of compliance with the regulations could be material.

Renewable Energy Standard

Kansas law mandates that we maintain a minimum amount of renewable energy sources. Through 2015 net renewable generation capacity must be 10% of the average peak retail 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. In 2012, we began purchasing under 20-year supply contracts the renewable energy produced from approximately 370 MW of additional wind generation, which, together with existing facilities, supply contracts and renewable energy credits, will allow us to satisfy the net renewable generation requirement through 2015. With our agreement to purchase an additional 200 MW of installed design capacity from a wind generation facility beginning in late 2016, we expect to meet the increased requirements through 2020. If we are unable to meet future requirements, our operations and consolidated financial results could be adversely impacted.

EPA Consent Decree

As part of a 2010 settlement of a lawsuit filed by the Department of Justice on behalf of the EPA, we are installing selective catalytic reduction (SCR) equipment on one of three JEC coal units by the end of 2014, which we estimate will cost approximately $230.0 million. We are installing less expensive NOx reduction equipment on the other two units to satisfy other terms of the settlement. We plan to complete these projects in 2014 and recover the costs to install these systems through our ECRR, but such recovery remains subject to the approval of our regulators.

FERC Investigation

The Federal Energy Regulatory Commission (FERC) opened a non-public investigation of our use of transmission service between July 2006 and February 2008. In May 2009, FERC staff alleged 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 and that we received $14.3 million of unjust profits through such activities. Based on our response to these allegations, FERC staff substantially revised downward its preliminary conclusions to allege that we received $0.9 million of unjust profits and failed to pay $0.8 million to the SPP for transmission service. As of December 31, 2012, we had recorded a liability of $1.6 million related to the potential settlement of this investigation and the risks of litigating this matter to a final outcome. We settled with FERC in January 2013 for $1.6 million.

Nuclear Decommissioning

Nuclear decommissioning is a nuclear industry term for the permanent shutdown of a nuclear power plant and the removal of radioactive components in accordance with 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 of a funding schedule prepared by the owner of the plant detailing how it plans to fund the future-year dollar amount of its pro rata share of the decommissioning costs.

In 2011 we revised the nuclear decommissioning study. Based on the study, our share of decommissioning costs, including decontamination, dismantling and site restoration, is estimated to be $296.2 million. This amount compares to the prior site study estimate of $279.0 million. The site study cost estimate represents the estimate to decommission Wolf Creek as of the site study year. The actual nuclear decommissioning costs may vary from the estimates because of changes in regulations 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 a 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 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 $2.9 million in 2013, $3.2 million in 2012 and $3.2 million in 2011. We record our investment in the NDT fund at fair value, which approximated $175.6 million and $150.8 million as of December 31, 2013 and 2012, respectively.

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 $3.0 million in 2013, $3.6 million in 2012 and $3.1 million in 2011. We include these costs in fuel and purchased power expense on our consolidated statements of income. As of November 2013, a federal court of appeals ruled that the DOE must stop collecting this fee.

In 2010, the DOE filed a motion with the NRC to withdraw its then pending application to construct a national repository for the disposal of spent nuclear fuel and high-level radioactive waste at Yucca Mountain, Nevada. An NRC board denied the DOE's motion to withdraw its application and the DOE appealed that decision to the full NRC. In 2011, the NRC issued an evenly split decision on the appeal and also ordered the licensing board to close out its work on the DOE's application by the end of 2011 due to a lack of funding. These agency actions prompted the States of Washington and South Carolina, and a county in South Carolina, to file a lawsuit in a federal Court of Appeals asking the court to compel the NRC to resume its license review and to issue a decision on the license application. In August 2013, the court ordered the NRC to resume its review of the DOE's application. 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.

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 dispose 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 and believes it will be able to expand that storage capacity if needed.

Nuclear Insurance

We maintain nuclear liability, property, and business interruption insurance for Wolf Creek. These policies contain certain industry standard terms, conditions and exclusions, including, but not limited to, ordinary wear and tear and war. An industry aggregate limit of $3.2 billion plus any reinsurance, indemnity or any other source recoverable by Nuclear Electric Insurance Limited (NEIL), our property and business interruption insurance provider, exists for acts of terrorism affecting Wolf Creek or any other NEIL insured plant within 12 months from the date of the first act. The $3.2 billion maximum recovery limit is not applicable, however, in the event of a "certified act of terrorism" as defined in the Terrorism Risk Insurance Act of 2002, as amended by the Terrorism Risk Insurance Program Reauthorization Act of 2007. In addition, we may be required to participate in industry-wide retrospective assessment programs as discussed below.

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 current limit of public liability, approximately $13.6 billion. This limit of liability consists of the maximum available commercial insurance of $375.0 million and the remaining $13.2 billion is provided through mandatory participation in an industry-wide retrospective assessment program. In addition, Congress could impose additional revenue-raising measures to pay claims. Under this retrospective assessment program, the owners of Wolf Creek are jointly and severally subject to an assessment of up to $127.3 million (our share is $59.8 million), payable at no more than $19.0 million (our share is $8.9 million) per incident per year per reactor. Both the total and yearly assessment is subject to an inflationary adjustment every five years with the next adjustment in 2018.

Nuclear Property and Business Interruption 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. In the event of an accident, insurance proceeds must first be used for reactor stabilization and site decontamination in accordance with a plan mandated by the NRC. Our share of any remaining proceeds can be used to pay for property damage or, if certain requirements are met, including decommissioning the plant, toward a shortfall in the NDT fund. The owners also carry additional insurance with NEIL to cover costs of replacement power and other extra expenses incurred during a prolonged outage resulting from accidental property damage at Wolf Creek. If significant losses were incurred at any of the nuclear plants insured under the NEIL policies, we may be subject to retrospective assessments under the current policies of approximately $34.4 million (our share is $16.1 million).

Accidental Nuclear Outage Insurance

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 effect on our consolidated financial results.

Fuel, Purchased Power and Transmission Commitments

To supply a portion of the fuel requirements for our power plants, the owners of Wolf Creek have entered into various contracts to obtain nuclear fuel and we have entered into various contracts to obtain coal and natural gas. Some of these contracts contain provisions for price escalation and minimum purchase commitments. As of December 31, 2013, our share of Wolf Creek's nuclear fuel commitments was approximately $41.3 million for uranium concentrates expiring in 2017, $6.1 million for conversion expiring in 2017, $109.0 million for enrichment expiring in 2025 and $41.1 million for fabrication expiring in 2023.

As of December 31, 2013, our coal and coal transportation contract commitments under the remaining terms of the contracts were approximately $900.6 million. The contracts are for plants that we operate and expire at various times through 2021.

As of December 31, 2013, our natural gas transportation contract commitments under the remaining terms of the contracts were approximately $117.2 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 five separate wind generation facilities with installed design capacities of 715 MW expiring in 2028 through 2036. Of the 715 MW under contract, 200 MW are associated with an agreement pursuant to which a generation provider is scheduled to deliver power beginning in 2016. Each of the agreements provide for our receipt and purchase of energy produced at a fixed price per unit of output. We estimate that our annual cost of energy purchased from these wind generation facilities will be approximately $68.2 million.

We have acquired rights to transmit a total of 306 MW of power. Agreements providing transmission capacity for approximately 200 MW expire in 2016 while the remaining 106 MW expire in 2022. As of December 31, 2013, we are committed to spend approximately $33.8 million over the remaining terms of these agreements.

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 generation 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,	
	2013	2012
	(In Thousands)	
Beginning ARO	$ 152,648	$ 142,508
Liabilities settled	(973)	(1,389)
Accretion expense	9,007	8,454
Revisions in estimated cash flows	—	3,075
Ending ARO	$ 160,682	$ 152,648

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 retirement obligation for the ash landfills 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 collect in our prices the costs to dispose of plant assets that do not represent legal retirement obligations. As of December 31, 2013 and 2012, we had $114.1 million and $129.0 million, respectively, in amounts collected, but not yet spent, for removal costs classified as a regulatory liability.

15. LEGAL PROCEEDINGS

In 2011, we reached agreements with two former executive officers settling all contractual obligations related to their previous employment. The agreements required us to make payments totaling approximately $57.0 million, pay approximately $8.4 million for their legal fees and expenses, and release deferred stock for compensation shares. We also reversed the remaining approximately $22.0 million of previously accrued liabilities in 2011, which reduced selling, general and administrative expense reported on our consolidated statement of income.

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 effect on our consolidated financial results. See Note 3, "Rate Matters and Regulation," and Note 13, "Commitments and Contingencies," for additional information.

16. COMMON AND PREFERRED STOCK

Common Stock

General

In 2011, Westar Energy shareholders approved an amendment to its Restated Articles of Incorporation to increase the number of shares of common stock authorized to be issued from 150.0 million to 275.0 million. As of December 31, 2013 and 2012, Westar Energy had issued 128.3 million shares and 126.5 million shares, respectively.

Westar Energy has a direct stock purchase plan (DSPP). Shares of common stock sold pursuant to the DSPP may be either original issue shares or shares purchased in the open market. During 2013 and 2012, Westar Energy issued 0.7 million shares and 0.8 million shares, respectively, through the DSPP and other stock-based plans operated under the LTISA Plan. As of December 31, 2013 and 2012, a total of 2.0 million shares and 1.5 million shares, respectively, were available under the DSPP registration statement.

Issuances

In September 2013, Westar Energy entered into two forward sale agreements with two banks. Under the terms of the agreements, the banks, as forward sellers, borrowed 8.0 million shares of Westar Energy's common stock from third parties and sold them to a group of underwriters for $31.15 per share. Pursuant to over-allotment options granted to the underwriters, the underwriters purchased in October 2013, an additional 0.9 million shares from the banks as forward sellers, increasing the total number of shares under the forward sale agreements to approximately 8.9 million. The underwriters received a commission equal to 3.5% of the sales price of all shares sold under the agreement. Westar Energy is required to settle such transactions within 24 months.

In March 2013, Westar Energy entered into a new, three-year sales agency financing agreement and master forward sale confirmation with a bank, similar to the sales agency financing agreement and master forward sale confirmation entered into in April 2010. The maximum amount that Westar Energy may offer and sell under the March 2013 master agreements is the lesser of an aggregate of $500.0 million or approximately 25.0 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. In addition, under the terms of the March 2013 sales agency financing agreement and master forward sale confirmation, 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 agent. The agent receives a commission equal to 1% of the sales price of all shares sold under the agreements. Westar Energy must settle the forward sale transactions within 18 months of the date each transaction is entered. Under the terms of March 2013 agreements and April 2010 agreements, during the year ended December 31, 2013, Westar Energy entered into transactions with respect to an aggregate of approximately 2.5 million shares of common stock and settled 1.1 million shares that had a 2012 vintage. As of December 31, 2013, 3.1 million shares could have been settled. In February 2014, Westar Energy settled 0.3 million shares with a physical settlement amount of approximately $9.2 million.

Assuming physical share settlement of the approximately 12.1 million shares associated with all forward sale transactions as of December 31, 2013, Westar Energy would have received aggregate proceeds of approximately $358.3 million based on a weighted average forward price of $29.73 per share.

The forward sale transactions are entered into at market prices; therefore, the forward sale agreements have no initial fair value. Westar Energy does 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 are initially priced when the transactions are entered into and are subject to certain fixed pricing adjustments during the term of the agreements. Accordingly, assuming physical share settlement, Westar Energy'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.

Preferred Stock Redemption

In May 2012, Westar Energy provided an irrevocable notice of redemption to holders of all of Westar Energy's preferred shares. Accordingly, we reduced preferred equity to zero, recognized the obligation to redeem the preferred shares as a liability and recognized the redemption premium as a preferred stock dividend. Payment was due to holders of the preferred shares effective July 1, 2012. The table below shows the redemption amounts for all series of preferred stock.

Rate	Shares	Principal Outstanding	Call Price	Premium	Total Cost to Redeem
		(Dollars in Thousands)			
4.50%	121,613	$ 12,161	108.0%	$ 973	$ 13,134
4.25%	54,970	5,497	101.5%	82	5,579
5.00%	37,780	3,778	102.0%	76	3,854
	214,363	$ 21,436		$ 1,131	$ 22,567

17. VARIABLE INTEREST ENTITIES

In determining the primary beneficiary of a VIE, we assess 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. Accounting guidance effective January 1, 2010, requires the primary beneficiary of a VIE to consolidate the VIE. The trusts holding our 8% interest in JEC, our 50% interest in La Cygne unit 2 and railcars we use to transport coal to some of our power plants are VIEs of which we are the primary beneficiary.

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 the 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

We leased railcars from an unrelated trust to transport coal to some of our power plants. We consolidated the trust as a VIE until the agreement expired in May 2013. As a result of deconsolidating the trust, property, plant and equipment of VIEs, net, and noncontrolling interests decreased $14.3 million.

We also lease railcars from another unrelated trust under an agreement that expires in November 2014. 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 railcars and lease them to us, and does not hold any other assets. We meet the requirements to be considered the primary beneficiary of this 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 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 trust that could potentially be significant if the fair value of the railcars at the end of the agreements is greater than the fixed amount. Our agreement with this trust also includes renewal options during which time we would pay a fixed amount of rent. We have the potential to receive benefits from the trust during the renewal period if the fixed amount of rent is less than the amount we would be required to pay under a new agreement.

Financial Statement Impact

We have recorded the following assets and liabilities on our consolidated balance sheets related to the VIEs described above.

	As of December 31,	
	2013	2012
	(In Thousands)	
Assets:		
Property, plant and equipment of variable interest entities, net	$ 296,626	$ 321,975
Regulatory assets (a)	6,792	5,810
Liabilities:		
Current maturities of long-term debt of variable interest entities	$ 27,479	$ 25,942
Accrued interest (b)	3,472	3,948
Long-term debt of variable interest entities, net	194,802	222,743

(a) Included in long-term regulatory assets on our consolidated balance sheets.
(b) Included in accrued interest on our consolidated balance sheets.

All of the liabilities noted in the table above relate to the purchase of the 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.

18. LEASES

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. Rental expense and estimated future commitments under operating leases are as follows.

Year Ended December 31,	Total Operating Leases
	(In Thousands)
Rental expense:	
2011	$ 17,577
2012	17,080
2013	16,484
Future commitments:	
2014	$ 14,384
2015	11,980
2016	10,232
2017	8,383
2018	5,248
Thereafter	15,361
Total future commitments	$ 65,588

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 eight years depending on the type of vehicle. Computer equipment has a lease term of three to five years.

In 2012, we signed an agreement to lease electrical facilities that connect a wind generating facility to the transmission system. The agreement extends through August 2032, at which time it may be extended or we may exercise an option to purchase the line. The terms of the agreement meet the criteria of a capital lease; therefore, we recorded an $8.3 million capital lease.

Assets recorded under capital leases, including the 2012 lease described above presented as generation plant, are listed below.

	As of December 31,	
	2013	2012
	(In Thousands)	
Vehicles	$ 12,141	$ 12,594
Computer equipment	1,758	1,423
Generation plant	48,346	48,346
Accumulated amortization	(10,493)	(6,928)
Total capital leases	$ 51,752	$ 55,435

Capital leases 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)
2014	$ 6,464
2015	5,891
2016	5,179
2017	4,711
2018	4,664
Thereafter	72,135
	99,044
Amounts representing imputed interest	(44,992)
Present value of net minimum lease payments under capital leases	54,052
Less: Current portion	3,249
Total long-term obligation under capital leases	$ 50,803

19. QUARTERLY RESULTS (UNAUDITED)

Our 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.

2013	First	Second	Third	Fourth
	(In Thousands, Except Per Share Amounts)			
Revenues (a)	$ 546,212	$ 569,589	$ 694,974	$ 559,878
Net income (a)	53,256	69,451	135,095	43,061
Net income attributable to Westar Energy, Inc. (a)	51,144	67,188	133,125	41,062
Per Share Data (a):				
Basic:				
Earnings available	$ 0.40	$ 0.53	$ 1.04	$ 0.32
Diluted:				
Earnings available	$ 0.40	$ 0.52	$ 1.04	$ 0.32
Cash dividend declared per common share	$ 0.34	$ 0.34	$ 0.34	$ 0.34
Market price per common share:				
High	$ 33.35	$ 34.96	$ 34.31	$ 32.56
Low	$ 28.59	$ 30.13	$ 29.79	$ 29.95

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

2012		First		Second		Third		Fourth
	(In Thousands, Except Per Share Amounts)							
Revenues (a)	$	475,677	$	566,262	$	695,758	$	523,772
Net income (a)		29,237		64,462		141,067		47,695
Net income attributable to common stock (a)		27,282		61,361		139,281		45,607
Per Share Data (a):								
Basic:								
Earnings available	$	0.21	$	0.48	$	1.10	$	0.36
Diluted:								
Earnings available	$	0.21	$	0.48	$	1.09	$	0.36
Cash dividend declared per common share	$	0.33	$	0.33	$	0.33	$	0.33
Market price per common share:								
High	$	29.13	$	30.17	$	33.04	$	30.29
Low	$	27.12	$	26.80	$	28.96	$	27.33

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

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

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.

In 2013 we completed the implementation a new Enterprise Resource Planning (ERP) system for our financial, accounting, and supply chain functions that changes our business and financial transaction processes used in those functions. This implementation represents a change in our internal control over financial reporting. In connection with this implementation, we updated our internal controls over financial reporting, as necessary, to accommodate modifications to our business processes and accounting procedures.

There were no changes in our internal control over financial reporting during the three months ended December 31, 2013, 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 2014 Annual Meeting of Shareholders to be filed pursuant to Regulation 14A (2014 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 *Additional Information - Section 16(a) Beneficial Ownership Reporting Compliance* in our 2014 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 *Election of Directors - Corporate Governance Matters* in our 2014 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 2014 Proxy Statement under the captions *Compensation Discussion and Analysis*, *Compensation Committee Report*, *Compensation of Executive Officers*, *Director Compensation* 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 2014 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 2014 Proxy Statement under the caption *Election of Directors - 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 2014 Proxy Statement under the caption of *Ratification and Confirmation of Deloitte and Touche LLP as Our Independent Registered Public Accounting Firm for 2014* and its subsections captioned *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, 2013 and 2012
Consolidated Statements of Income for the years ended December 31, 2013, 2012 and 2011
Consolidated Statements of Cash Flows for the years ended December 31, 2013, 2012 and 2011
Consolidated Statements of Changes in Equity for the years ended December 31, 2013, 2012 and 2011
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 with "*" 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)	Amendment to Sales Agency Financing Agreement, dated May 26, 2010, among Westar Energy, Inc., BNY Mellon Capital Markets, LLC, and The Bank of New York Mellon (filed as Exhibit 1(a) to the Form 10-Q for the period ended June 30, 2012 filed on August 7, 2012)	I
1(b)	Second Amendment to Sales Agency Financing Agreement, dated May 9, 2012, among Westar Energy, Inc., BNY Mellon Capital Markets, LLC, and The Bank of New York Mellon (filed as Exhibit 1(b) to the Form 10-Q for the period ended March 31, 2012 filed on May 9, 2012)	I
1(c)	Sales Agency Financing Agreement, dated March 21, 2013, with BNY Mellon Capital Markets, LLC and The Bank of New York Mellon (filed as Exhibit 1.1 to the Form 8-K filed on March 22, 2013)	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 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(e)	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(f)	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(g)	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(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 March 31, 1998 filed on May 12, 1998)	I

3(i)	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(j)	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(k)	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(l)	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
3(m)	Certificate of Amendment to Restated Articles of Incorporation of Westar Energy, Inc.	#
3(n)	Form of Certificate of Decertification of Preference Shares	#
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)	Senior 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(k)	Form of Senior Note (included in Exhibit 4(j))	I
4(l)	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(m)	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(n)	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(o)	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(p)	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(q)	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(r)	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(s)	Form of First Mortgage Bonds, 6.10% Series Due 2047 (contained in Exhibit 4(r))	I
4(t)	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(u)	Form of Forty-Second Supplemental Indenture, dated as of March 1, 2012 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 February 29, 2012)	I
4(v)	Form of Forty-Second Supplemental (Reopening) Indenture, dated as of May 17, 2012 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 May 16, 2012)	I
4(w)	Form of Forty-Third Supplemental Indenture, dated as of March 28, 2013, by and between Westar Energy, Inc. and The Bank of New York Mellon Trust Company, N.A., as successor trustee to Harris Trust and Savings Bank (filed as Exhibit 4.1 to the Form 8-K filed on March 22, 2013)	I
4(x)	Form of Forty-Fourth Supplemental Indenture, dated as of August 19, 2013, by and between Westar Energy, Inc. and The Bank of New York Mellon Trust Company, N.A., as successor trustee to Harris Trust and Savings Bank (filed as Exhibit 4.1 to the Form 8-K filed on August 14, 2013)	I
4(y)	Fifty-Eighth Supplemental Indenture, dated as of February 12, 2013, 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 15, 2013)	I
	Instruments defining the rights of holders of other long-term debt not required to be filed as Exhibits will be furnished to the Commission upon request.	
10(a)	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(b)	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(c)	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(d)	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(e)	Form of Change in Control Agreement (filed as Exhibit 10.1 to the Form 8-K filed on January 26, 2006)*	I
10(f)	Westar Energy, Inc. Form of Restricted Share Units Award (filed as Exhibit 10(aq) to the Form 10-K for the period ended December 31, 2009, filed on February 25, 2010)	I
10(g)	Westar Energy, Inc. Form of Performance Based Restricted Share Units Award (filed as Exhibit 10(ar) to the Form 10-K for the period ended December 31, 2009 filed on February 25, 2010)	I
10(h)	Westar Energy, Inc. Form of First Transition Performance Based Restricted Share Units Award (filed as Exhibit 10(as) to the form 10-K for the period ended December 31, 2009 filed on February 25, 2010)	I
10(i)	Westar Energy, Inc. Form of Second Transition Performance Based Restricted Share Units Award (filed as Exhibit 10(at) to the Form 10-K for the period ended December 31, 2009 filed on February 25, 2010)	I
10(j)	Form of Amended and Restated Change in Control Agreement with Officers of Westar Energy, Inc. (filed as Exhibit 10(au) to the Form 10-K for the period ended December 31, 2009 filed on February 25, 2010)	I
10(k)	Westar Energy, Inc. Retirement Benefit Restoration Plan (filed as Exhibit 10.1 to the Form 8-K filed on April 2, 2010)	I
10(l)	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
10(m)	Amendment to Long-Term Incentive and Share Award Plan (filed as Exhibit 10 to the Form 8-K filed on May 6, 2011)	I
10(n)	Amendment to Restricted Share Units Awards between Westar Energy, Inc. and William B. Moore (filed as Exhibit 10.1 to the Form 8-K filed on July 6, 2011)	I
10(o)	Fourth Amended and Restated Credit Agreement dated as of September 29, 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 September 29, 2011)	I
10(p)	First Extension Agreement dated as of February 12, 2013, among Westar Energy, Inc. and several banks and other financial institutions party thereto (filed as Exhibit 10.1 to the Form 8-K filed on February 15, 2013)	I
10(q)	Master Confirmation for Forward Stock Sale Transactions, dated March 21, 2013, between Westar Energy, Inc. and The Bank of New York Mellon (filed as Exhibit 10.1 to the Form 8-K filed on March 22, 2013)	I
10(r)	Confirmation of Forward Sale Transaction, dated September 24, 2013, between JPMorgan Chase Bank, National Association, London Branch and Westar Energy, Inc. (filed as Exhibit 10.1 to the Form 8-K filed on September 27, 2013)	I

10(s)	Confirmation of Forward Sale Transaction, dated September 24, 2013, between Wells Fargo Bank, National Association and Westar Energy, Inc. (filed as Exhibit 10.2 to the Form 8-K filed on September 27, 2013)	I
10(t)	Confirmation of Additional Forward Stock Sale Transaction, dated October 16, 2013, between JPMorgan Chase Bank, National Association, London Branch and Westar Energy, Inc. (filed as Exhibit 10.1 to the Form 8-K filed on October 17, 2013)	I
10(u)	Confirmation of Additional Forward Stock Sale Transaction, dated October 16, 2013, between Wells Fargo Bank, National Association and Westar Energy, Inc. (filed as Exhibit 10.2 to the Form 8-K filed on October 17, 2013)	I
10(v)	Second Extension Agreement dated as of February 14, 2014, among Westar Energy, Inc. and several banks and other forward institutions or entities from time to time parties to the Agreement	#
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)	#
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, 2011				
Allowances deducted from assets for doubtful accounts	$ 5,729	$ 8,774	$ (7,119)	$ 7,384
Year ended December 31, 2012				
Allowances deducted from assets for doubtful accounts	$ 7,384	$ 6,617	$ (9,085)	$ 4,916
Year ended December 31, 2013				
Allowances deducted from assets for doubtful accounts	$ 4,916	$ 7,039	$ (7,359)	$ 4,596

(a) Result from 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 26, 2014	By:	/s/ ANTHONY D. SOMMA
			Anthony D. Somma
			Senior Vice President, Chief Financial Officer and Treasurer

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/ MARK A. RUELLE (Mark A. Ruelle)	Director, President and Chief Executive Officer (Principal Executive Officer)	February 26, 2014
/s/ ANTHONY D. SOMMA (Anthony D. Somma)	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial and Accounting Officer)	February 26, 2014
/s/ CHARLES Q. CHANDLER IV (Charles Q. Chandler IV)	Chairman of the Board	February 26, 2014
/s/ MOLLIE H. CARTER (Mollie H. Carter)	Director	February 26, 2014
/s/ R. A. EDWARDS III (R. A. Edwards III)	Director	February 26, 2014
/s/ JERRY B. FARLEY (Jerry B. Farley)	Director	February 26, 2014
/s/ RICHARD L. HAWLEY (Richard L. Hawley)	Director	February 26, 2014
/s/ B. ANTHONY ISAAC (B. Anthony Isaac)	Director	February 26, 2014
/s/ ARTHUR B. KRAUSE (Arthur B. Krause)	Director	February 26, 2014
/s/ SANDRA A. J. LAWRENCE (Sandra A. J. Lawrence)	Director	February 26, 2014
/s/ MICHAEL F. MORRISSEY (Michael F. Morrissey)	Director	February 26, 2014
/s/ S. CARL SODERSTROM JR. (S. Carl Soderstrom Jr.)	Director	February 26, 2014

SECOND EXTENSION AGREEMENT

THIS SECOND EXTENSION AGREEMENT, dated as of February 14, 2014 (this "Agreement"), among WESTAR ENERGY, INC., a Kansas corporation (the "Borrower"), Kansas Gas and Electric Company, a Kansas corporation (the "Guarantor"), the several banks and other financial institutions or entities from time to time parties to this Agreement (the "Lenders"), WELLS FARGO BANK, NATIONAL ASSOCIATION, as administrative agent (in such capacity, the "Administrative Agent"), BANK OF AMERICA, N.A., as syndication agent, and THE BANK OF NEW YORK MELLON, CITIBANK, N.A., J.P. MORGAN SECURITIES LLC, and UNION BANK, N.A., as documentation agents.

RECITALS

A. The Borrower, the banks and other financial institutions party thereto and the Administrative Agent are parties to that certain Credit Agreement dated as of February 18, 2011 (as amended, restated, supplemented or otherwise modified from time to time, the "Credit Agreement"). Capitalized terms used herein without definition shall have the meanings given to them in the Credit Agreement as they may be modified pursuant to this Agreement.

B. The Borrower, the Lenders and the Administrative Agent are parties to that certain First Extension Agreement dated as of February 12, 2013, which extended the Revolving Termination Date by one year pursuant to Section 2.1(b) of the Credit Agreement.

C. The Borrower has requested a second one-year extension of the Revolving Termination Date pursuant to Section 2.1(b) of the Credit Agreement and the Lenders signatory hereto have approved such request.

STATEMENT OF AGREEMENT

NOW, THEREFORE, in consideration of the foregoing and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto agree as follows:

SECTION 1. EXTENSION

Pursuant to Section 2.1(b) of the Credit Agreement, the Borrower provided not less than 65 days' written notice to the Administrative Agent prior to February 18, 2014 (the "Noticed Anniversary Date") of its request to extend the Revolving Commitments. As of the date hereof, Lenders (the "Extending Lenders") holding more than fifty percent (50%) of the Total Revolving Commitments outstanding on the Noticed Anniversary Date have approved the Borrower's request to extend the Revolving Commitments and, subject to the satisfaction of the conditions precedent set forth in Section 2, the Revolving Termination Date as to the Extending Lenders shall be extended for an additional year from the then-applicable Revolving Termination Date. The Revolving Termination Date as to any Declining Lender remains unchanged.

SECTION 2. CONDITIONS PRECEDENT

The extension of the Revolving Termination Date pursuant to Section 1 shall become effective as of the date when, and only when, each of the following conditions precedent shall have been satisfied (the "Extension Date"):

(a) The Administrative Agent (or its counsel) shall have received from the Borrower, the Guarantor and the Extending Lenders holding more than fifty percent (50%) of the Total Revolving

Commitments outstanding on the Noticed Anniversary Date either (i) a counterpart of this Agreement signed on behalf of such party or (ii) written evidence satisfactory to the Administrative Agent (which may include facsimile or other electronic image scan transmission of a signed signature page of this Agreement) that such party has signed a counterpart of this Agreement.

(b) The Borrower shall have paid:

(A) to the Administrative Agent, for the account of each Extending Lender, an extension fee in the amount of 0.06% of such Extending Lender's Revolving Commitment as of the Extension Date, which extension fee once paid will be fully earned and nonrefundable; and

(B) all other fees and reasonable expenses of the Administrative Agent and the Lenders required under the Credit Agreement and any other Loan Document to be paid on or prior to the Extension Date (including reasonable fees and expenses of counsel) in connection with this Agreement.

(c) The Administrative Agent shall have received a certificate, dated the Extension Date and signed by an authorized officer of the Borrower, confirming (i) no Default or Event of Default shall have occurred and be continuing on the Extension Date and after giving effect thereto and (ii) the representations and warranties set forth in SECTION 3 hereof, if not qualified as to materiality, shall be true and correct in all material respects and all other representations and warranties set forth in SECTION 3 hereof shall be true and correct, in each case on and as of the Extension Date (or other such date expressly provided in SECTION 3 hereof) with the same force and effect as if made on or as of the Extension Date (or other such date expressly provided in SECTION 3 hereof).

(d) Subject to Borrower's and KGE's rights under Section 22 of the KGE Collateral Agreement, (x) the Collateral Agent shall have received the physical delivery of a new mortgage bond in certificated form, registered in the name of the Collateral Agent and issued under the KGE Indenture in a principal amount equal to the Total Revolving Commitments and a term equivalent to the Revolving Termination Date as extended hereby and (y) the Security Documents shall have been amended as necessary in accordance with Section 3(e) of the KGE Collateral Agreement to treat such new mortgage bond as a Pledged Bond subject to the first priority lien of the Collateral Agent, for the ratable benefit of the Secured Parties (as defined in the KGE Collateral Agreement).

SECTION 3. REPRESENTATIONS AND WARRANTIES

The Borrower represents and warrants to the Administrative Agent and the Lenders that (i) each of the representations and warranties contained in Section 3 of the Credit Agreement , if not qualified as to materiality, are true and correct in all material respects and all other representations and warranties set forth in Section 3 of the Credit Agreement are true and correct, in each case on and as of the Extension Date, both immediately before and after giving effect to this Agreement (except for those representations and warranties or parts thereof that, by their terms, expressly relate solely to a specific date, in which case such representations and warranties, if not qualified as to materiality, shall be true and correct in all material respects and all such other representations and warranties shall be true and correct, in each case as of such specific date), (ii) this Agreement has been duly authorized, executed and delivered by the Borrower and constitutes the legal, valid and binding obligation of the Borrower enforceable against it in accordance with its terms and (iii) no Default or Event of Default shall have occurred and be continuing on the Extension Date, both immediately before and after giving effect to this Agreement.

SECTION 4. ACKNOWLEDGMENT AND CONFIRMATION OF THE BORROWER AND GUARANTOR

Each of the Borrower and Guarantor hereby confirms and agrees that after giving effect to this Agreement, the Credit Agreement and the other Loan Documents remain in full force and effect and enforceable against it in accordance with their respective terms and shall not be discharged, diminished, limited or otherwise affected in any respect. Each of the Borrower and Guarantor represents and warrants to the Lenders that it has no knowledge of any claims, counterclaims, offsets, or defenses to or with respect to its obligations under the Loan Documents, or if the Borrower or Guarantor has any such claims, counterclaims, offsets, or defenses to the Loan Documents or any transaction related to the Loan Documents, the same are hereby waived, relinquished, and released in consideration of the execution of this Agreement. This acknowledgment and confirmation by the Borrower and Guarantor is made and delivered to induce the Administrative Agent and the Lenders to enter into this Agreement. Each of the Borrower and Guarantor acknowledges that the Administrative Agent and the Lenders would not enter into this Agreement in the absence of the acknowledgment and confirmation contained herein.

SECTION 5. MISCELLANEOUS

(a) GOVERNING LAW. THIS AGREEMENT AND THE RIGHTS AND OBLIGATIONS OF THE PARTIES UNDER THIS AGREEMENT SHALL BE GOVERNED BY, AND CONSTRUED AND INTERPRETED IN ACCORDANCE WITH, THE LAW OF THE STATE OF NEW YORK (INCLUDING SECTIONS 5-1401 AND 5-1402 OF THE NEW YORK GENERAL OBLIGATIONS LAW, BUT EXCLUDING ALL OTHER CHOICE OF LAW AND CONFLICTS OF LAW RULES).

(b) Full Force and Effect. Except as expressly modified hereby, the Credit Agreement and the other Loan Documents shall continue in full force and effect in accordance with the provisions thereof on the date hereof. As used in the Credit Agreement, “hereinafter,” “hereto,” “hereof,” and words of similar import shall, unless the context otherwise requires, mean the Credit Agreement after giving effect to this Agreement. Any reference to the Credit Agreement or any of the other Loan Documents herein or in any such documents shall refer to the Credit Agreement and Loan Documents as modified hereby. This Agreement is limited as specified and shall not constitute or be deemed to constitute an amendment, modification or waiver of any provision of the Credit Agreement or the other Loan Documents except as expressly set forth herein. This Agreement shall constitute a Loan Document under the terms of the Credit Agreement.

(c) Expenses. The Borrower agrees on demand (i) to pay all reasonable fees and expenses of counsel to the Administrative Agent, and (ii) to reimburse the Administrative Agent for all reasonable out-of-pocket costs and expenses, in each case, in connection with the preparation, negotiation, execution and delivery of this Agreement and the other Loan Documents delivered in connection herewith.

(d) Severability. Any provision of this Agreement that is prohibited or unenforceable in any jurisdiction shall, as to such jurisdiction, be ineffective to the extent of such prohibition or unenforceability without invalidating the remaining provisions hereof, and any such prohibition or unenforceability in any jurisdiction shall not invalidate or render unenforceable such provision in any other jurisdiction.

(e) Successors and Assigns. This Agreement shall be binding upon, inure to the benefit of and be enforceable by the respective successors and permitted assigns of the parties hereto.

(f) Construction. The headings of the various sections and subsections of this Agreement have been inserted for convenience only and shall not in any way affect the meaning or construction of any of the provisions hereof. The provisions of Section 1.2 of the Credit Agreement are hereby incorporated by reference as if fully set forth herein.

(g) Counterparts. This Agreement may be executed by one or more of the parties to this Agreement on any number of separate counterparts, and all of said counterparts taken together shall be deemed to constitute one and the same instrument. Delivery of an executed signature page of this Agreement by facsimile transmission or by email shall be effective as delivery of a manually executed counterpart hereof. A set of the copies of this Agreement signed by all the parties shall be lodged with the Borrower and the Administrative Agent.

1.1

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be duly executed by their respective authorized officers as of the day and year first above written.

WESTAR ENERGY, INC., as Borrower

By: __

Anthony D. Somma
Senior Vice President, Chief Financial Officer and Treasurer

KANSAS GAS AND ELECTRIC COMPANY, as Guarantor

By: __

Anthony D. Somma
Vice President and Treasurer

WELLS FARGO BANK, NATIONAL ASSOCIATION, as Administrative Agent, as an Issuing Lender and as a Lender
By: __
Name: __
Title: __

[Lender]

By: __
Name: __
Title: __

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,				
	2013	2012	2011	2010	2009
Earnings from continuing operations (a)	$ 421,449	$ 406,638	$ 339,274	$ 293,591	$ 200,226
Fixed Charges:					
Interest (expensed and capitalized) (b)	193,873	186,736	178,049	179,272	162,217
Interest on corporate-owned life insurance borrowings	57,767	63,518	66,326	68,926	68,401
Interest applicable to rentals (b)	5,495	4,675	4,528	4,325	22,353
Total Fixed Charges (c)	257,135	254,929	248,903	252,523	252,971
Distributed income of equity investees	—	—	—	—	—
Preferred Dividend Requirements:					
Preferred dividends	—	1,616	970	970	970
Income tax required	—	723	424	396	404
Total Preferred Dividend Requirements (d)	—	2,339	1,394	1,366	1,374
Total Fixed Charges and Preferred Dividend Requirements	257,135	257,268	250,297	253,889	254,345
Earnings (e)	$ 678,584	$ 661,567	$ 588,177	$ 546,114	$ 453,197
Ratio of Earnings to Fixed Charges	2.64	2.60	2.36	2.16	1.79
Ratio of Earnings to Combined Fixed Charges and Preferred Dividend Requirements	2.64	2.57	2.35	2.15	1.78

(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 are reported as interest expense beginning 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.

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-187398 on Form S-3, and Registration Statement Nos. 333-175293, 333-70891 and 333-151104 on Form S-8 of our reports dated February 26, 2014, relating to (1) the consolidated financial statements and financial statement schedule of Westar Energy, Inc. and subsidiaries, and (2) 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, 2013.

/s/ Deloitte & Touche LLP

Kansas City, Missouri
February 26, 2014

Exhibit 31(a)

WESTAR ENERGY, INC.
CHIEF EXECUTIVE 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, 2013, 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
   a. 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 26, 2014	By:	/s/ Mark A. Ruelle
			Mark A. Ruelle
			Director, President and Chief Executive Officer
			Westar Energy, Inc.
			(Principal Executive Officer)

Exhibit 31(b)

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

I, Anthony D. Somma, certify that:

1. I have reviewed this annual report on Form 10-K for the period ended December 31, 2013, 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 26, 2014

By: /s/ Anthony D. Somma

Anthony D. Somma
Senior Vice President, Chief Financial Officer and Treasurer
Westar Energy, Inc.
(Principal Accounting Officer)

Exhibit 32

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, 2013 (the Report), which this certification accompanies, Mark A. Ruelle, in my capacity as Director, President and Chief Executive Officer of the Company, and Anthony D. Somma, in my capacity as Senior Vice President, Chief Financial Officer and Treasurer 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 26, 2014	By:	/s/ Mark A. Ruelle
			Mark A. Ruelle
			Director, President and Chief Executive Officer
Date:	February 26, 2014	By:	/s/ Anthony D. Somma
			Anthony D. Somma
			Senior Vice President, Chief Financial Officer and Treasurer