WESTAR ENERGY INC /KS
Form 10-K
February 21, 2018

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, 2017

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, a smaller reporting company, or an emerging growth company (as defined in Rule 12b-2 of the Act). Check one:
Large accelerated filer X Accelerated filer Non-accelerated filer Smaller reporting company Emerging growth company
If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Act.
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 $7,533,791,379 at June 30, 2017.

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	142,233,037 shares
(Class)	(Outstanding at February 14, 2018)

DOCUMENTS INCORPORATED BY REFERENCE:

Information required by Items 10-14 of Part III of this Form 10-K will be incorporated by reference to Westar Energy, Inc.'s definitive proxy statement with respect to its 2018 Annual Meeting of Shareholders, if such definitive proxy statement is filed with the Securities and Exchange Commission on or before April 30, 2018. Due to the pending merger with Great Plains Energy Incorporated, we may not be required to file a definitive proxy statement, in which case we will file an amendment to this Form 10-K on or before April 30, 2018 to include the information that is otherwise incorporated by reference.

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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
BNSF	BNSF Railway Company
Btu	British thermal units
CAA	Clean Air Act
CCR	Coal combustion residuals
CO	Carbon monoxide
CO_2	Carbon dioxide
COLI	Corporate-owned life insurance
CPP	Clean Power Plan
CWA	Clean Water Act
CWIP	Construction work in progress
DOE	Department of Energy
DSPP	Direct Stock Purchase Plan
ELG	Effluent Limitations Guidelines
EPA	Environmental Protection Agency
EPS	Earnings per share
Exchange Act	Securities Exchange Act of 1934
FERC	Federal Energy Regulatory Commission
FMBs	First mortgage bonds
GHG	Greenhouse gas
Great Plains Energy	Great Plains Energy Incorporated
IM	Integrated Marketplace
IRC	Internal Revenue Code of 1986, as amended
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
Merger	Pending merger of equals between Westar Energy, Inc. and Great Plains Energy Incorporated
MPSC	Public Service Commission of the State of Missouri
MMBtu	Millions of British thermal units
MW	Megawatt(s)
MWh	Megawatt hour(s)
NAAQS	National Ambient Air Quality Standards
NAV	Net Asset Value
NDT	Nuclear Decommissioning Trust
NEIL	Nuclear Electric Insurance Limited
NOx	Nitrogen oxides
NO_2	Nitrogen dioxide
NRC	Nuclear Regulatory Commission
NSPS	New source performance standards

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PCB	Polychlorinated biphenyl
PM	Particulate matter
PRB	Powder River Basin
Prairie Wind	Prairie Wind Transmission, LLC
ROE	Return on equity
RSU	Restricted share unit
RTO	Regional transmission organization
S&P 500	Standard & Poor’s 500 Index
S&P Electric Utilities	Standard & Poor’s Electric Utility Index
SO_2	Sulfur dioxide
SPP	Southwest Power Pool, Inc.
SSCGP	Southern Star Central Gas Pipeline
TCJA	Tax Cuts and Jobs Act
TFR	Transmission formula rate
VaR	Value-at-Risk
VIE	Variable interest entity
Wolf Creek	Wolf Creek Generating Station
WOTUS	Waters of the United States

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FORWARD-LOOKING STATEMENTS

Certain matters discussed in this Annual Report on Form 10-K are “forward-looking statements.” The Private Securities Litigation Reform Act of 1995 has established that these statements qualify for safe harbors from liability. Forward-looking statements may include words like we “believe,” “anticipate,” “target,” “expect,” “estimate,” “intend” and wo 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:

- the pending merger of equals (merger) between Westar Energy, Inc. and Great Plains Energy Incorporated (Great Plains Energy), including the expected timing of closing the merger and costs expected to be incurred in connection with the merger,
- amount, type and timing of capital expenditures,
- earnings,
- cash flow,
- liquidity and capital resources,
- litigation,
- accounting and tax matters,
- 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:

- risks related to operating in a heavily regulated industry that is subject to unpredictable political, legislative, judicial and regulatory developments, which can impact our operations, results of operations, and financial condition,
- the difficulty of predicting the magnitude and timing of changes in demand for electricity, including with respect to emerging competing services and technologies and conservation and energy efficiency measures,
- the impact of weather conditions, including as it relates to sales of electricity and 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 and funding obligations, 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 changing laws and regulations relating to air and greenhouse gas (GHG) 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,
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- changes in regulation of nuclear generating facilities and nuclear materials and fuel, including possible shutdown or required modification of nuclear generating facilities,
- uncertainties with respect to procurement of nuclear fuel and related services, which are dependent on a single supplier,
- 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 security and information and operating systems security considerations,
- risks arising from changes in federal and state tax laws, regulations and interpretations, and related actions by regulatory commissions,

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- changes in accounting requirements and other accounting matters,
- changes in the energy markets in which we participate, such as the development and implementation of real time and next day trading markets, and the effect of the retroactive repricing of transactions in such markets following execution because of changes or adjustments in market pricing mechanisms by regional transmission organizations (RTOs) and independent system operators,
- reduced demand for coal-based energy because of actual or perceived climate impacts and the development of alternate energy sources,
- current and future litigation, regulatory investigations, proceedings or inquiries,
- cost of fuel used in generation and wholesale electricity prices,
- certain risks and uncertainties associated with the merger, including, without limitation, those related to:
- the timing of, and the conditions imposed by, regulatory approvals required for the merger,
- the occurrence of any event, change or other circumstances that could give rise to the termination of the merger agreement or could otherwise cause the failure of the merger to close,
- the outcome of any legal proceedings, regulatory proceedings or enforcement matters that have been or may be instituted in connection with the merger,
- the receipt of an unsolicited offer from another party to acquire our assets or capital stock (or those of Great Plains Energy) that could interfere with the proposed merger,
- the timing to consummate the proposed merger,
- disruption from the proposed merger making it more difficult to maintain relationships with customers, employees, regulators or suppliers,
- the diversion of management time and attention on the merger,
- the amount of costs, fees, expenses and charges related to the merger,
- the possibility that the expected value creation from the merger will not be realized, or will not be realized within the expected time period,
- difficulties related to the integration of the two companies,
- the credit ratings of the combined company following the merger, and
- the effect and timing of changes in laws or in governmental regulations (including environmental laws and regulations) that could adversely affect our participation in the merger, 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 and in conjunction with the other reports we file from time to time with the SEC. No one section of this report deals with all aspects of the subject matter and additional information on some matters that could impact our consolidated financial results may be included in the other reports we file from time to time with the SEC. 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.

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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 708,000 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, clean and diverse energy supply portfolio. In doing so, we continue to expand renewable generation, build and upgrade our energy infrastructure and develop systems and programs with regard to how our customers use energy and interact with us. In addition, we entered into an amended and restated agreement and plan of merger with Great Plains Energy that provides for a merger of equals between the two companies. The closing of the merger is subject to customary closing conditions, including receipt of regulatory approvals. See “Item 1A. Risk Factors” and Note 3 of the Notes to Consolidated Financial Statements, “Pending Merger,” for additional information.

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,		
	2017	2016	2015
Residential	32 %	33 %	31 %
Commercial	28 %	29 %	29 %
Industrial	16 %	16 %	16 %
Wholesale	12 %	12 %	13 %
Transmission	11 %	9 %	10 %

Other	1 %	1 %	1 %
Total	100%	100%	100%

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

	Year Ended December 31, 2017	2016	2015
Residential	32 %	33 %	33 %
Commercial	38 %	39 %	39 %
Industrial	30 %	28 %	28 %
Total	100%	100%	100%

Generating Capability and Firm Capacity Purchases

We have 6,602 megawatts (MW) of generating capability in service. Further, we purchase electricity pursuant to long-term contracts from renewable generation facilities with an installed design capacity of 1,232 MW. See “Item 2. Properties” for additional information about our generating units. Our generating capability and net generation by source as of December 31, 2017, are summarized below.

Source	Capability (MW)	Percent of Total Capability	Net Generation (MWh)	Percent of Total Net Generation
Coal	3,250	41 %	14,855,367	54 %
Nuclear	552	7 %	5,004,571	18 %
Natural gas/diesel	2,370	31 %	1,712,307	6 %
Renewable (a)	1,662	21 %	6,161,823	22 %
Total	7,834	100 %	27,734,068	100 %

(a) Due to the intermittent nature of wind generation, 230 MW of net accredited generating capacity is associated with our wind generation facilities.

In 2017, we generated or purchased the equivalent of 58% of our total retail sales from emission-free resources. These resources also made up 40% of our total net generation.

In March 2017, we completed construction and placed into operation Western Plains Wind Farm, a wind generating facility with a designed installed capability of 281 MW.

Our aggregate 2017 peak system net load of 5,242 MW occurred in July 2017. Our net accredited generating capacity, combined with firm capacity purchases and sales and potentially interruptible load, provided a reserve margin of 17% above system peak responsibility at the time of our 2017 peak system net load, which satisfied Southwest Power Pool, Inc. (SPP) planning requirements.

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

Utility (a)	Capacity (MW)	Expiration
Mid-Kansas Electric Company, LLC	174	January 2019
City of Chanute	Up to 45	December 2020
Midwest Energy, Inc.	115	May 2022
Kansas Power Pool	59	December 2022
Midwest Energy, Inc.	150	May 2025
Total	543	

(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 2017, we provided approximately 95 MW to, and received approximately 144 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.

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Fuel Matters

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 the volume of fuel that is required to produce a given amount of electricity. We measure the quantity of heat consumed during the generation of electricity in millions of British thermal units (MMBtu).

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

	2017	2016	2015
Per MMBtu:			
Nuclear	$0.64	$0.68	$0.66
Coal	1.80	1.80	1.77
Natural gas	3.55	3.24	3.64
Diesel	12.51	11.51	15.55
All generating stations	1.74	1.76	1.74
Per MWh Generation:			
Nuclear	$6.45	$6.91	$6.72
Coal	20.25	19.71	19.78
Natural gas/diesel	34.29	31.80	37.16
All generating stations	18.16	18.37	18.44

Our wind production, which produced 22% of our total generation, has no associated fuel costs and is, therefore, not included in the table above.

Fossil Fuel Generation

Coal

Jeffrey Energy Center (JEC): The three coal-fired units at JEC have an aggregate capacity of 2,175 MW, of which we own or lease a combined 92% share, or 2,001 MW. We have a long-term coal supply contract with Blackjewel Marketing and Sales, LLC 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 or assesses a charge to the extent the minimum quantities are not achieved. 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 redetermination every five years to provide an adjusted price for the ensuing five years that reflects the market prices at the time of redetermination. The most recent price adjustment was effective January 1, 2018.

The BNSF Railway Company (BNSF) and Union Pacific Railroad Company transport coal to JEC under long-term rail transportation contracts. The terms of these contracts continue through December 31, 2020, at which time we plan to enter into new contracts. These contracts provide for minimum annual deliveries or assess a charge to the extent the minimum deliveries are not achieved. The contract price in each contract is subject to price escalation based on certain costs incurred by the railroads.

La Cygne Generating Station (La Cygne): The two coal-fired units at La Cygne have an aggregate generating capacity of 1,398 MW. Our share of the units is 50%, or 699 MW, of which we either own directly or consolidate through a variable interest entity (VIE). 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 90% of La Cygne's PRB coal requirements are under contract for 2018. About 80% of those commitments under contract are fixed price for 2018. 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. These contracts provide for minimum annual deliveries or assess a charge to the extent the minimum deliveries are not achieved.

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Lawrence and Tecumseh Energy Centers: Lawrence and Tecumseh Energy Centers have an aggregate generating capacity of 550 MW. We purchase PRB coal for these energy centers under a contract with Arch Coal, Inc. that provides for 100% of the coal requirements for these facilities through 2019. The contract provides for minimum annual deliveries or assesses a charge to the extent the minimum deliveries are not achieved. BNSF transports coal for these energy centers under a contract that expires in December 2020.

Natural Gas

We use natural gas as a primary fuel at our Gordon Evans, Murray Gill, Hutchinson, Spring Creek and Emporia Energy Centers and at the State Line facility. We can also use natural gas as a supplemental fuel in the coal-fired units at Lawrence and Tecumseh Energy Centers. Natural gas accounted for approximately 7% of the total MMBtu of fuel we consumed and approximately 15% of our total fuel expense in 2017. 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 expires in April 2020, and the agreement for Lawrence and Tecumseh Energy Centers expires in April 2030. The agreement for the State Line facility extends through October 2022, while the agreement for Emporia Energy Center is in place until December 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 1,174 MW nuclear power plant located near Burlington, Kansas. KGE owns a 47% interest in Wolf Creek, or 552 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 March 2027. The owners also have under contract all of the uranium enrichment and all of the 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.

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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 refueling and maintenance outages. In the fall of 2016, Wolf Creek underwent a planned refueling and maintenance outage. Our share of the outage costs was approximately $24.2 million. In early 2018, Wolf Creek will undergo a planned maintenance outage. We expect our share of the outage to be approximately $21.8 million.

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 14 of the Notes to Consolidated Financial Statements, “Commitments and Contingencies,” and “Item 1A. Risk Factors,” for additional information regarding our nuclear operations.

Wind Energy

Wind is our primary source of renewable energy. As of December 31, 2017, we owned approximately 430 MW of designed installed wind capability and had under contract the purchase of wind energy produced from approximately 1,225 MW of designed installed wind capability. In March 2017, we placed Western Plains Wind Farm into service, a wind generating facility with a designed installed capability of 281 MW.

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. In 2017, purchased power comprised approximately 32% of our total fuel and purchased power expense. Our weighted average cost of purchased power per Megawatt hour (MWh) was $23.01 in 2017, $24.82 in 2016 and $27.28 in 2015.

Transmission

Regional Transmission Organization

The Federal Energy Regulatory Commission (FERC) requires owners of regulated transmission assets to allow third parties non-discriminatory 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 14 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 prices 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.

Southwest Power Pool Integrated Marketplace

We participate in the SPP Integrated Marketplace (IM), which is similar to organized power markets currently operating in other RTOs. The IM impacts how we commit and sell the output from our generation facilities and buy power to meet the needs of our customers. The SPP has the authority to start and stop generating units participating in the market and selects the lowest cost resource mix to meet the needs of the various SPP customers while ensuring reliable operations of the transmission system.

Transmission Investments

We own a 50% interest in Prairie Wind Transmission, LLC (Prairie Wind), which is a joint venture between us and Electric Transmission America, LLC, which itself is a joint venture between affiliates of American Electric Power Company, Inc. and Berkshire Hathaway Energy Company. In 2014, Prairie Wind completed construction on, and energized, a 108-mile 345 kV double-circuit transmission line that is now being used to provide transmission service in the SPP.

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We continue to evaluate and participate in transmission planning activities in accordance with FERC Order No. 1000, which revised FERC's process for planning enhancements and expansions of the electric transmission grid and the corresponding process for allocating costs thereof, in areas we believe it makes sense to do so. We believe we have opportunities to develop transmission infrastructure, including projects pursuant to which we, as the incumbent, have a right of first refusal and those projects that are subject to the Order No. 1000 competitive processes. However, we currently have no investments associated with Order No. 1000 in our forecasted capital expenditure table, and the merger will change the manner and extent to which we continue to participate in the Order No. 1000 process.

Regulation and Our Prices

Kansas law gives the Kansas Corporation Commission (KCC) general regulatory authority over our retail 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 a formula that tracks changes in our costs, which reduces 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 4 of the Notes to Consolidated Financial Statements, "Rate Matters and Regulation," for information regarding our rate proceedings with the KCC and FERC.

Environmental Matters

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, including coal combustion residuals (CCRs). These laws and regulations oftentimes 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 capital and other expenditures to comply with environmental laws and regulations.

See "Item 1A. Risk Factors" and Notes 4 and 14 of the Notes to Consolidated Financial Statements, "Rate Matters and Regulation - KCC Proceedings - Environmental Costs" and "Commitments and Contingencies - Environmental Matters," respectively, for more information regarding environmental trends, risks and laws and regulations.

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 have measures in place to promote the safety and health of our employees and to monitor our compliance with such laws and regulations.

Information Technology

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. These networks and systems are in some cases owned or managed by third-party service providers. Cybersecurity breaches, criminal activity, terrorist attacks and other disruptions to our information technology infrastructure, including infrastructure owned by third-parties we utilize, could interfere with our operations, could expose us or our customers or employees to a risk of loss and could expose us to liability or regulatory penalties or cause us reputational damage or other harm to our business. We have taken measures to secure our network and systems, but such measures may not be sufficient, especially due to the increasing sophistication of cyberattacks. See “Item 1A. Risk Factors” for additional information.

SEASONALITY

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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 14, 2018, we had 2,205 employees, 1,117 of which were covered by a contract with Locals 304 and 1523 of the International Brotherhood of Electrical Workers that extends through June 30, 2018.

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	56	Director, President and Chief Executive Officer (since August 2011)	
Bruce A. Akin	53	Senior Vice President, Power Delivery (since January 2015)	Westar Energy, Inc. Vice President, Power Delivery (February 2012 to December 2014)
Jerl L. Banning	57	Senior Vice President, Operations Support and Administration (since January 2015)	Westar Energy, Inc. Vice President, Human Resources and IT (January 2014 to December 2014) Vice President, Human Resources (February 2010 to December 2013)
John T. Bridson	48	Senior Vice President, Generation and Marketing (since January 2015)	Westar Energy, Inc. Vice President, Generation (February 2011 to December 2014)
Gregory A. Greenwood	52	Senior Vice President, Strategy (since August 2011)	
Anthony D. Somma	54	Senior Vice President, Chief Financial Officer and Treasurer (since August 2011)	
Larry D. Irick	61	Vice President, General Counsel and Corporate Secretary (since February 2003)	
Kevin L. Kongs	55	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.

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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 value of our equity and debt 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.

Risks Relating to our Business

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 impact 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 or 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 a formula that tracks 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 that are 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 obtaining or 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 effect on our consolidated financial results.

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Our costs of compliance with environmental laws and regulations, including those relating to GHG emissions, are significant, and the future costs of compliance with environmental laws and regulations could adversely impact our operations and consolidated financial results.

We are subject to extensive federal, state and local environmental laws 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. These laws and regulations oftentimes 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.

Costs of compliance with environmental laws and regulations or fines or penalties resulting from non-compliance, if not recovered in our prices, could adversely impact 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 or 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 1. Business - Environmental Matters,” “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations - Executive Summary - Current Trends and Uncertainties - Environmental Regulation” and Notes 4 and 14 of the Notes to Consolidated Financial Statements, “Rate Matters and Regulation - KCC Proceedings - Environmental Costs” and “Commitments and Contingencies - Environmental Matters,” respectively, for additional information. In addition, compliance with environmental laws and regulations could alter the manner in which we had planned to manage our assets, which in turn could require us to retire assets earlier than expected or record asset retirement obligations (AROs).

In addition, we combust large amounts of fossil fuels as we produce electricity. This results in significant emissions of carbon dioxide (CO_2) and other GHGs through the operation of our power plants. Federal legislation regulates the emission of GHGs and numerous states and regions have adopted programs to stabilize or reduce GHG emissions. The Environmental Protection Agency (EPA) regulates GHGs under the Clean Air Act. In October 2015, the EPA published a rule limiting CO_2 emissions for new, modified and reconstructed coal and natural gas fueled electric generating units, along with a rule regulating emissions from existing power plants. In 2017, the EPA announced that it is reviewing the rules regarding new, modified, and reconstructed coal and natural gas electric generating units, and has proposed to effectively repeal the rule relating to existing power plants. See Note 14 of the Notes to Consolidated Financial Statements, “Commitments and Contingencies - Environmental Matters” for additional information. We believe rules that regulate or limit our emissions could have a material impact on our operations and consolidated financial results.

Further, in the course of operating our coal generation plants, we produce CCRs, including fly ash, gypsum and bottom ash, which we must handle, recycle, process or dispose of. We historically have recycled some of our ash production, principally by selling to the aggregate industry. The EPA published a rule to regulate CCRs in April 2015, which will require additional CCR handling, processing and storage equipment and potential closure of certain ash disposal areas. We have recorded, and may need to record additional AROs, in connection with the rule. See Note 14 of the Notes to Consolidated Financial Statements, “Commitments and Contingencies - Environmental Matters” for additional information. The impact of this rule 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 adverse effect on our consolidated financial results.

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

Our operations are impacted by economic conditions. Adverse economic conditions, including a prolonged recession, no or low economic growth 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, including coal and natural gas, 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.

A number of our commercial and industrial customers have geographically dispersed facilities, and localized factors, including economic conditions, governmental or other incentives and other factors that influence customer operating or capital expenses, may cause these customers to curtail or eliminate operations at facilities in our service territory and move them to other facilities with competitive advantages. In addition, 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 procurement of nuclear fuel and related services;
- 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.

An incident at Wolf Creek could have a material impact 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 or a retrospective premium assessment under our nuclear insurance coverage, both of which could increase Wolf Creek's costs and impact our consolidated financial results. Such events could also result in a shutdown of Wolf Creek.

In addition, Wolf Creek is reliant on a sole supplier for fuel and related services, which is currently the subject of Chapter 11 reorganization proceedings, and an extended outage of Wolf Creek could occur if the supplier is not able to perform under its contracts with Wolf Creek. Switching to another supplier could take an extended amount of time, and would require NRC approval. An extended outage at Wolf Creek could affect the amount of our Wolf Creek investment included in our prices, and could have a material impact on our consolidated financial results.

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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 experience varies from our forecasts, or if our regulators disagree with the prudence of certain of our decisions, we could be required to increase our AROs or record impairment charges, and our consolidated financial results may be adversely impacted.

Our planned capital investments subject us to risks.

Our business requires significant capital expenditures. 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 credit and capital markets, 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 internally generated cash, access to capital markets, and 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. The Tax Cuts and Jobs Act (TCJA) will reduce our internally generated cash, which might adversely impact the manner in which our credit rating is evaluated. These could adversely impact 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 impact 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 impacted.

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Physical and cybersecurity breaches, criminal activity, terrorist attacks and other disruptions to our facilities or our information technology infrastructure could interfere with our operations, expose us or our customers or employees to a risk of loss and expose us to liability or regulatory penalties or cause 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 networks and 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. These networks and systems are in some cases owned or managed by third-party service providers. In the ordinary course of business, we collect, store and transmit sensitive data including 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, as well as the networks and infrastructure belonging to third-party service providers that we utilize, may be vulnerable to damage, disruptions or shutdowns due to attacks or breaches by hackers or other unauthorized third parties; error or malfeasance by one or more of our or our service providers' employees; software or hardware upgrades; additions or replacements; malicious software code; telecommunication failures; natural disasters or other catastrophic events. The occurrence of any of these events could, among other things, impact the reliability or safety of our generation, transmission and distribution systems; result in the erasure of data or render our equipment unusable; impact our ability to conduct business in the ordinary course; expose us and our customers, employees and vendors to a risk of loss or misuse of information; and result in legal claims or proceedings, liability or regulatory penalties against us, damage our reputation or otherwise harm our business. 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.

We are subject to laws and rules issued by multiple government agencies concerning safeguarding and maintaining the confidentiality of our security, customer and business information. For example, NERC has issued comprehensive regulations and standards surrounding the security of bulk power systems, and is continually in the process of developing updated and additional requirements with which the utility industry must comply. The NRC also has issued regulations and standards related to the protection of critical digital assets at nuclear power plants. Compliance with NERC and NRC rules and standards, and rules and standards promulgated by other regulatory agencies from time to time, will increase our compliance costs and our exposure to the potential risk of violations of these rules and standards, which includes potential financial penalties. Furthermore, the non-compliance of other utilities with applicable regulations or the occurrence of a serious security event at other utilities could result in increased regulation or oversight, both of which could increase our costs and impact our consolidated financial results.

Additionally, we cannot predict the impact that any future information technology or terrorist attack may have on the energy industry in general. The electric utility industry, both within the United States and internationally, has experienced physical and cybersecurity attacks on energy infrastructure such as power plants, substations, and related assets in the past, and there may be more attacks in the future. 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. Any of the foregoing could adversely impact our operations or financial results.

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 outages because of equipment failure, weather, transmission system disruption, operator error, contractor or subcontractor failure and other factors. 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.

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Recent comprehensive tax legislation could adversely affect our consolidated financial results and liquidity. In addition, we may not be able to fully utilize net operating loss, tax credit or other tax carryforwards, or realize expected production tax credits related to our wind farms, all of which could adversely impact our consolidated financial results and liquidity.

Major tax legislation, known as the TCJA, was signed into law in December 2017. The TCJA significantly reforms the Internal Revenue Code of 1986, as amended (IRC), and is generally effective January 1, 2018. The TCJA contains significant changes to federal corporate income taxation, including, in general and among other things, reducing the federal corporate income tax rate from 35% to 21%, limiting the deduction for net operating losses, eliminating net operating loss carrybacks and eliminating our use of bonus depreciation on new capital investments. Due to the complexity of the TCJA, including any possible future legislation that amends the TCJA, the limited guidance from regulatory agencies, including the Internal Revenue Service, FERC and the KCC, and contemporaneous state dockets, including one in Kansas dedicated to the impact of the TCJA, the overall impact of the TCJA on us is uncertain, and our business, as well as the business of the combined companies following closing of the merger, could be adversely affected by the TCJA or related regulatory proceedings and actions.

The TCJA will reduce our revenues and internally generated cash flows due to the reduced collection of taxes in customer prices. Due to the reasons noted above, this reduction could be more than we anticipate and could adversely affect our consolidated financial results and liquidity. In addition, the reduction in the corporate tax rate may result in a reduction of deferred income tax assets and liabilities currently recorded, and may result in one or more charges to our results of operations to the extent that the assets and liabilities are not attributable to our rate regulated business. Further, there may be other material adverse effects resulting from the legislation that we have not yet identified.

Over the last several years, our income tax obligations have been reduced due to the continued use of bonus depreciation provisions that allow for an acceleration of deductions for tax purposes and IRS guidance on tax deductions for repairs. Although the TCJA expands bonus depreciation in general, it eliminates bonus depreciation for regulated utilities on new capital investments. We assess our future ability to utilize tax benefits, including those in the form of net operating loss, tax credit and other tax carryforwards, that are recorded as deferred income tax assets on our balance sheets to determine whether a valuation allowance is necessary. A reduction in, or disallowance of these tax benefits resulting from a legislative change or adverse determination by a taxing jurisdiction could have an adverse impact on our consolidated financial results and liquidity. Additionally, changes in corporate tax rates or policy changes, such as those resulting from the TCJA, as well as any inability to generate enough taxable income in the future to utilize all of our tax benefits before they expire, could have an adverse impact on our consolidated financial results and liquidity.

In addition, we operate wind farms that generate production tax credits for us to use to reduce our federal income tax obligations. The amount of production tax credits we earn is dependent on the level of electricity output generated by our wind farms and the applicable tax credit rate. A variety of operating and economic parameters, including transmission constraints, adverse weather conditions and breakdown or failure of equipment, could significantly reduce the production tax credits generated by our wind farms, which could have an adverse impact on 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 have taken and will continue to take 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, as well as related to the storage of energy produced by these systems. Adoption of these technologies may increase because of advancements or government subsidies reducing the cost of generating or storing electricity through these technologies to a level that is competitive with our current methods of generating electricity. There is also a perception that generating or storing 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. 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.

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Risks Relating to the Pending Merger

We cannot provide any assurance that the merger will be completed. Failure to complete the merger could negatively affect the trading price of our common stock and our future business and financial results.

The closing of the merger is subject to various conditions, including, among others, (i) receipt of all required regulatory approvals from, among others, the FERC, NRC, KCC, and Public Service Commission of the State of Missouri (MPSC) (provided that such approvals do not result in a material adverse effect on Great Plains Energy or Westar Energy and their respective subsidiaries, after giving effect to the merger, measured on the size and scale of Westar Energy and its subsidiaries, taken as a whole); (ii) effectiveness of the registration statement for the shares of the new holding company common stock to be issued to Westar Energy and Great Plains Energy shareholders in the merger and approval of the listing of such shares on the New York Stock Exchange; (iii) the absence of any material adverse effect with respect to Westar Energy, Great Plains Energy and their respective subsidiaries; (iv) the absence of laws or judgments, whether preliminary, temporary or permanent, which may prevent, make illegal or prohibit the completion of the merger; (v) subject to certain materiality exceptions, the accuracy of the representations and warranties made by Westar Energy and Great Plains Energy, respectively, and compliance by Westar Energy and Great Plains Energy with their respective obligations under the amended and restated merger agreement; (vi) the receipt of tax opinions by us and Great Plains Energy that the merger will be treated as a non-taxable event for U.S. federal income tax purposes; (vii) there being no shares of Great Plains Energy preference stock outstanding; and (viii) Great Plains Energy having not less than $1.25 billion in cash or cash equivalents on its balance sheet.

Although we and Great Plains Energy have agreed in the merger agreement to use our reasonable best efforts to take, or cause to be taken, all actions, and do, or cause to be done, and assist and cooperate with the other parties in doing, all things necessary to cause the conditions to the closing of the merger to be satisfied or to effect the closing of the merger as promptly as reasonably practicable, the conditions to the merger may not be satisfied and the merger agreement could be terminated. In addition, satisfying the conditions to the merger may take longer than, and could cost more than, we and Great Plains Energy expect. The occurrence of any of these events individually or in combination could negatively affect the trading price of our common stock and our future business and financial results and subject us to the following:

- negative reactions from the financial markets, including declines in the price of our common stock due to the fact that the current price may reflect a market assumption that the merger will be completed;
- performance shortfalls and missed opportunities as a result of the diversion of our management's attention by the merger; and
- potential payments by us to Great Plains Energy for damages, or if the merger agreement is terminated under certain circumstances, a termination fee of $190.0 million.

The merger is subject to the receipt of consent or approval from governmental entities that could delay the completion of the merger or impose conditions that could have a material adverse effect on the combined company.

Completion of the merger is conditioned upon, among other things, the receipt of consents, orders, approvals or clearances, as required, from, among others, the FERC, NRC, KCC and MPSC (provided that such approvals do not result in a material adverse effect on Great Plains Energy or Westar Energy and their respective subsidiaries, after giving effect to the merger, measured on the size and scale of Westar Energy and its subsidiaries, taken as a whole).

On April 19, 2017, the KCC rejected the original proposed acquisition of Westar Energy by Great Plains Energy, and we are unable to predict how the KCC will evaluate the new proposed merger. A substantial delay in obtaining satisfactory approvals or the imposition of unfavorable terms or conditions in connection with such approvals could adversely affect the business, financial condition or results of operations of us or Great Plains Energy or may result in the termination of the merger agreement. Failure to receive satisfactory approvals may also make any alternative future strategic transaction more challenging, which could in turn negatively impact the price of our common stock.

For additional information on the status of various approvals in connection with the pending merger, see Notes 3 and 14 of the Notes to Consolidated Financial Statements, “Pending Merger” and “Commitments and Contingencies,” respectively.

The anticipated benefits of combining the companies may not be realized.

We entered into the amended and restated merger agreement with the expectation that the merger would result in various benefits, including, among other things, synergies, cost savings and operating efficiencies. However, the achievement of the anticipated benefits of the merger, including the synergies, may not materialize or may take longer than expected to materialize. In addition, the TCJA significantly reforms the IRC and may impact the timing and extent of benefits previously expected from the merger. In addition, we may not be able to integrate our operations with Great Plains Energy's existing operations without encountering difficulties, including inconsistencies in standards, systems and controls, and without diverting management's focus and resources from ordinary business activities and opportunities. Any of the foregoing could have a material adverse effect on the combined company.

We will incur significant transaction and transition costs in connection with the merger.

We and Great Plains Energy expect to incur significant transaction and transition costs in connection with the consummation of the merger and the subsequent integration of the companies (in addition to the costs we and Great Plains Energy have already incurred on the prior proposed acquisition of us). Prior to consummation of the merger, we may also incur additional costs to maintain employee morale and to retain key employees. Great Plains Energy will also incur significant fees and expenses in connection with unwinding financing arrangements that were implemented to finance the prior proposed acquisition of us. These expenses could reduce or eliminate the savings that we expect to achieve from the merger, and accordingly, any net benefits may not be achieved in the near term or at all. These transaction and transition expenses may result in significant charges taken against earnings by us prior to the completion of the merger and by the combined company following the completion of the merger.

We will be subject to business uncertainties and contractual restrictions while the merger is pending, which could adversely affect our business.

Uncertainty about the impact of the merger, including on employees and customers, may have an adverse effect on us and Great Plains Energy and, consequently, on the combined company. These uncertainties may impair our and Great Plains Energy's ability to attract, retain and motivate personnel, and could cause customers, suppliers and others that deal with us to seek to change existing business relationships with us and/or Great Plains Energy. If employees depart, our business or the combined company's business could be harmed. In addition, the merger agreement restricts us, without the consent of Great Plains Energy, and Great Plains Energy, without our consent, from taking specified actions until the merger is completed or the amended and restated merger agreement terminates. These restrictions may prevent us or Great Plains Energy from pursuing otherwise attractive business opportunities and making other changes to our respective businesses.

Pending litigation against us and Great Plains Energy may adversely affect the combined company's business, financial condition or results of operations following the merger.

Following the announcement of the original merger agreement, a putative derivative lawsuit was filed in the District Court of Shawnee County, Kansas against the members of our board of directors, Great Plains Energy and a subsidiary of Great Plains Energy, alleging breaches of various fiduciary duties by members of our board of directors in connection with the original proposed transaction and alleging that Great Plains Energy and a subsidiary of Great Plains Energy aided and abetted such alleged breaches of fiduciary duties. The putative derivative petition was refiled in October 2017. Also following the announcement of the original merger agreement, two putative class action lawsuits (which were consolidated and superseded by a consolidated complaint) were filed in the District Court of Shawnee County, Kansas against Westar Energy, the members of our board of directors and Great Plains Energy, alleging breaches of various fiduciary duties by the members of our board of directors in connection with the proposed merger and alleging that we and Great Plains Energy aided and abetted such alleged breaches of fiduciary duties. In September 2017, the lead plaintiffs moved to amend the class action petition with allegations similar to those made regarding the original merger agreement but focusing on the revised merger. Also in September 2017, a putative class action lawsuit was filed in the United States District Court for the District of Kansas challenging the merger and alleged disclosure violations under sections 14(a) and 20(a) of the Securities Exchange Act of 1934, as amended (Exchange Act). In October 2017, another putative class action lawsuit was filed in the United States District Court for the District of Kansas. This federal class action complaint challenges the merger and alleges violations of sections

14(a) and 20(a) of the Exchange Act.

On November 16, 2017, the parties in each of the actions independently agreed to withdraw requests for injunctive relief and otherwise agreed in principle to dismissing the actions with prejudice and to providing releases. In the future, the parties will prepare and present to the court for approval Stipulations of Settlement that will, if accepted by the court, settle the actions in their entirety. The outcome of litigation is inherently uncertain. The defense or settlement of any lawsuit or claim that remains unresolved at the time the merger closes may adversely affect the combined company's business, financial condition or results of operation. See Note 16 of the Notes to Consolidated Financial Statements, "Legal Proceedings," for additional information.

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ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

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ITEM 2. PROPERTIES

Name	Location	Unit No.	Year Installed	Principal Source	Unit Capability (MW) By Owner (a) Westar Energy	KGE	Total Company Generation	Renewable Purchased Power	Total Generation and Renewable Purchased Power
Renewable Generation:									
Cedar Bluff	Ness & Trego Counties, KS	(a)	2015	Wind	—	—	—	199	199
Central Plains	Wichita County, KS	(a)	2009	Wind	99	—	99	—	99
Flat Ridge	Barber County, KS	(a)	2009	Wind	50	—	50	50	100
Hutchinson Community Solar	Hutchinson, KS		2017	Solar	—	—	—	1	1
Ironwood	Ford County, KS	(a)	2012	Wind	—	—	—	168	168
Kay Wind	Kay County, OK	(a)	2015	Wind	—	—	—	200	200
Kingman II	Kingman County, KS	(a)	2016	Wind	—	—	—	103	103
Meridian Way	Cloud County, KS	(a)	2008	Wind	—	—	—	96	96
Ninnescah	Pratt County, KS	(a)	2016	Wind	—	—	—	208	208
Post Rock	Ellsworth & Lincoln Counties, KS	(a)	2012	Wind	—	—	—	201	201
Rolling Meadows	Shawnee County, KS		2010	Landfill Gas	—	—	—	6	6
Western Plains	Ford County, KS	(a)	2017	Wind	281	—	281	—	281
Nuclear:									
Wolf Creek Generating Station (47%):	Burlington, KS	1 (b)	1985	Uranium	—	552	552	—	552
Coal:									
Jeffrey Energy Center (92%):	St. Marys, KS								
Steam Turbines		1 (b)	1978	Coal	524	146	670	—	670
		2 (b)	1980	Coal	526	146	672	—	672
		3 (b)	1983	Coal	516	143	659	—	659
La Cygne Station (50%):	La Cygne, KS								
Steam Turbines		1 (b)	1973	Coal	—	368	368	—	368
		2 (c)	1977	Coal	—	331	331	—	331
Lawrence Energy Center:	Lawrence, KS								

Steam Turbines		4	1960	Coal	111	—	111	—	111
		5	1971	Coal	373	—	373	—	373
Tecumseh Energy Center:	Tecumseh, KS								
Steam Turbines		7	1957	Coal	66	—	66	—	66

(a) Capability (except for wind generating facilities) represents accredited net generating capacity approved by the SPP. Capability for our wind generating facilities represents the installed design capacity. Due to the intermittent nature of wind generation, these facilities are associated with a total of 230 MW of accredited generating capacity.
(b) Westar Energy jointly owns State Line (40%) while KGE jointly owns La Cygne unit 1 (50%) and Wolf Creek (47%). We jointly own or lease 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 18 of the Notes to Consolidated Financial Statements, “Variable Interest Entities.”

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Name	Location	Unit No.	Year Installed	Principal Source	Unit Capability (MW) By Owner (a) Westar Energy	KGE	Total Company Generation	Renewable Purchased Power	Total Generation and Renewable Purchased Power
Gas and Diesel:									
Emporia Energy Center:	Emporia, KS								
Combustion Turbines		1	2008	Gas	45	—	45	—	45
		2	2008	Gas	44	—	44	—	44
		3	2008	Gas	43	—	43	—	43
		4	2008	Gas	44	—	44	—	44
		5	2008	Gas	158	—	158	—	158
		6	2009	Gas	155	—	155	—	155
		7	2009	Gas	157	—	157	—	157
Gordon Evans Energy Center:	Colwich, KS								
Steam Turbines		1	1961	Gas	—	154	154	—	154
		2	1967	Gas	—	376	376	—	376
Combustion Turbines		1	2000	Gas	73	—	73	—	73
		2	2000	Gas	72	—	72	—	72
		3	2001	Gas	149	—	149	—	149
Hutchinson Energy Center:	Hutchinson, KS								
Combustion Turbines		1	1974	Gas	54	—	54	—	54
		2	1974	Gas	56	—	56	—	56
		3	1974	Gas	55	—	55	—	55
		4	1975	Diesel	70	—	70	—	70
Murray Gill Energy Center:	Wichita, KS								
Steam Turbines		3	1956	Gas	—	104	104	—	104
		4	1959	Gas	—	92	92	—	92
Spring Creek Energy Center:	Edmond, OK								
Combustion Turbines		1	2001	Gas	69	—	69	—	69
		2	2001	Gas	69	—	69	—	69
		3	2001	Gas	67	—	67	—	67
		4	2001	Gas	68	—	68	—	68
	Joplin, MO								

State Line (40%):									
Combined Cycle	2-1	(b)	2001	Gas	62	—	62	—	62
	2-2	(b)	2001	Gas	63	—	63	—	63
	2-3	(b)	2001	Gas	71	—	71	—	71
Total					4,190	2,412	6,602	1,232	7,834

(a) Capability (except for wind generating facilities) represents accredited net generating capacity approved by the SPP. Capability for our wind generating facilities represents the installed design capacity. Due to the intermittent nature of wind generation, these facilities are associated with a total of 230 MW of accredited generating capacity.
(b) Westar Energy jointly owns State Line (40%) while KGE jointly owns La Cygne unit 1 (50%) and Wolf Creek (47%). We jointly own or lease 92% of JEC. Unit capacity amounts reflect our ownership and leased percentages only.

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We own and have in service approximately 6,400 miles of transmission lines, approximately 24,200 miles of overhead distribution lines and approximately 5,100 miles of underground distribution lines.

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

ITEM 3. LEGAL PROCEEDINGS

Information on legal proceedings is set forth in Notes 4, 14 and 16 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.

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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 14, 2018, Westar Energy had 14,955 common shareholders of record. For information regarding quarterly common stock price ranges for 2017 and 2016, see Note 20 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, 2012, and ended on December 31, 2017, 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 2012	Dec 2013	Dec 2014	Dec 2015	Dec 2016	Dec 2017
Westar Energy, Inc.	$100	$117	$156	$167	$229	$221
S&P© 500	$100	$132	$150	$153	$171	$208
S&P© Electric Utilities	$100	$113	$146	$139	$162	$181

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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 2017, Westar Energy's board of directors declared four quarterly dividends of $0.40 per share, reflecting an annual dividend of $1.60 per share, compared to four quarterly dividends of $0.38 per share in 2016, reflecting an annual dividend of $1.52 per share. On February 21, 2018, Westar Energy's board of directors declared a quarterly dividend of $0.40 per share payable to shareholders on April 2, 2018. The indicated annual dividend rate is $1.60 per share.

The merger agreement includes certain restrictions and limitations on our ability to declare dividend payments. The merger agreement, without prior approval of Great Plains Energy, limits our quarterly dividends declared to $0.40 per share.

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ITEM 6. SELECTED FINANCIAL DATA

	Year Ended December 31,				
	2017	2016	2015	2014	2013
	(In Thousands)				
Income Statement Data:					
Total revenues	$2,571,003	$2,562,087	$2,459,164	$2,601,703	$2,370,654
Net income	336,552	361,200	301,796	322,325	300,863
Net income attributable to Westar Energy, Inc.	323,920	346,577	291,929	313,259	292,520

	As of December 31,				
	2017	2016	2015	2014	2013
	(In Thousands)				
Balance Sheet Data:					
Total assets	$11,624,368	$11,487,074	$10,705,666	$10,288,906	$9,530,903
Long-term obligations (a)	3,846,191	3,699,328	3,379,219	3,433,320	3,466,984

	Year Ended December 31,				
	2017	2016	2015	2014	2013
Common Stock Data:					
Basic earnings per share available for common stock	$2.27	$ 2.43	$ 2.11	$ 2.40	$ 2.29
Diluted earnings per share available for common stock	2.27	2.43	2.09	2.35	2.27
Dividends declared per share	1.60	1.52	1.44	1.40	1.36
Book value per share	27.50	26.84	25.87	25.02	23.88
Average equivalent common shares outstanding (in thousands) (b) (c)	142,464	142,068	137,958	130,015	127,463

(a) Includes long-term debt, net, current maturities of long-term debt, capital leases, long-term debt of VIEs, net and current maturities of long-term debt of VIEs. See Note 18 of the Notes to Consolidated Financial Statements, “Variable Interest Entities,” for additional information regarding VIEs.

(b) In 2015, Westar Energy issued and sold approximately 9.7 million shares of common stock realizing proceeds of $258.0 million.

(c) In 2014, Westar Energy issued and sold approximately 3.4 million shares of common stock realizing proceeds of $87.7 million.

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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 wo 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 708,000 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.

Tax Cuts and Jobs Act

The TCJA, which was signed into law in December 2017, significantly reforms the IRC and is generally effective January 1, 2018. The TCJA contains significant changes to federal corporate income taxation, including, in general and among other things, reducing the federal corporate income tax rate from 35% to 21%, limiting the deduction for net operating losses, eliminating net operating loss carrybacks and eliminating our use of bonus depreciation on new capital investments.

We were required to remeasure deferred income tax assets and liabilities at the lower 21% corporate tax rate as of the date the TCJA was signed into law. As a result, we decreased net deferred income tax liabilities by approximately $1.0 billion and made corresponding adjustments to regulatory assets and regulatory liabilities. Nearly all of the benefit of the lower corporate tax rate will lower prices for our customers over a period generally corresponding to the life of our plant assets. In addition, in 2017 we decreased non-regulated net deferred income tax assets by approximately $12.2 million and correspondingly recorded an increase in income tax expense, which increased our effective tax rate by 2.5%.

Changes to income tax expense that are included in our prices occur through either rate review, by updating prices through formulas for transmission and wholesale prices or other regulatory action. We expect that future price changes for providing retail and wholesale electricity and transmission service will retroactively apply the lower 2018 income tax expense. Due to the nature of the regulatory process, and the inherent delay in our ability to adjust our prices, we may collect revenue in 2017 that is reflective of the higher corporate tax rate in effect prior to the passage of the TCJA. Therefore, we will reflect the expectation of retroactive application of lower prices in 2018 revenues and, correspondingly, we will accrue a regulatory liability representing our obligation to return these amounts to customers once the new prices are approved or otherwise take effect. We estimate that the lower prices will result in approximately $85.0 million less per year in revenues and a corresponding decrease in income tax expense. Further, we expect approximately $85.0 million less in cash receipts from customers due to less income tax included in our prices, which may require us to raise additional debt.

Proposed Merger with Great Plains Energy

On May 29, 2016, we entered into an agreement and plan of merger with Great Plains Energy that provided for the acquisition of Westar Energy by Great Plains Energy. On April 19, 2017, the KCC rejected the prior transaction.

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On July 9, 2017, we entered into an amended and restated agreement and plan of merger with Great Plains Energy that provides for a merger of equals between the two companies. Upon closing, each issued and outstanding share of our common stock will be converted into one share of common stock of a new holding company with a final name still to be determined. Upon closing, each issued and outstanding share of Great Plains Energy common stock will be converted into 0.5981 shares of common stock of the new holding company. Following completion of the merger, our shareholders are expected to own approximately 52.5% of the new holding company and Great Plains Energy's shareholders are expected to own approximately 47.5% of the new holding company. Our shareholders and Great Plains Energy's shareholders approved their respective merger-related proposals on November 21, 2017. We currently expect to close the transaction in the first half of 2018. For more information, see Notes 3, 14 and 16 of the Notes to Consolidated Financial Statements, "Pending Merger," "Commitments and Contingencies" and "Legal Proceedings," respectively, and Item "1A. Risk Factors."

In July 2017, we announced that we intend to retire unit 7 at Tecumseh Energy Center, units 3 and 4 at Murray Gill Energy Center, and units 1 and 2 at Gordon Evans Energy Center in 2018, subject to the completion of the merger. The decision was based in part on lower demand for energy from the plants. The depreciable lives of the assets have been, and continue to be, based upon us operating as a stand-alone entity. Retiring these units or any other assets identified as part of integration planning could result in the retirement of assets prior to the end of their estimated useful lives or recording a loss on obsolete inventory.

Earnings Per Share

Following is a summary of our net income and basic earnings per share (EPS) for the years ended December 31, 2017 and 2016.

	Year Ended December 31,		
	2017	2016	Change
	(Dollars in Thousands, Except Per Share Amounts)		
Net income attributable to Westar Energy, Inc.	$323,920	$346,577	$(22,657)
Earnings per common share, basic	2.27	2.43	(0.16)

Net income attributed to Westar Energy, Inc. and basic EPS for the year ended December 31, 2017, as compared to the year ended December 31, 2016, decreased due primarily to lower retail sales attributable to milder weather and recording less in corporate-owned life insurance (COLI) benefits. Partially offsetting these decreases were lower income tax expense due to lower income before income taxes.

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 laws and regulations;
- the availability of and our access to liquidity and capital resources; and

- capital market conditions.

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Strategy

We expect to continue operating as a vertically integrated, regulated electric utility. Significant elements of our strategy include maintaining a flexible, clean and diverse energy supply portfolio. In doing so, we continue to expand renewable generation, build and upgrade our energy infrastructure and develop systems and programs with regard to how our customers use energy and interact with us. In addition, we entered into an amended and restated agreement and plan of merger with Great Plains Energy that provides for a merger of equals between the two companies. The closing of the merger is subject to customary closing conditions, including receipt of regulatory approvals. See "Item 1A. Risk Factors" and Note 3 of the Notes to Consolidated Financial Statements, "Pending Merger," for additional information.

Current Trends and Uncertainties

Environmental Regulation

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. There are a variety of final and proposed laws and regulations that could have a material adverse effect on our operations and consolidated financial results. See Note 14 of the Notes to Consolidated Financial Statements, "Commitments and Contingencies—Environmental Matters," for a discussion of environmental costs, laws, regulations and other contingencies.

Allowance for Funds Used During Construction

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 (CWIP). 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,		
	2017	2016	2015
	(In Thousands)		
Borrowed funds	$5,605	$9,964	$3,505
Equity funds	1,996	11,630	2,075
Total	$7,601	$21,594	$5,580
Average AFUDC Rates	2.3 %	4.2 %	2.7 %

We expect AFUDC for both borrowed funds and equity funds to fluctuate based on the timing and manner in which we finance our capital expenditures.

Interest Expense

We expect a slight increase in our interest expense over the next several years as a result of our need to raise a modest amount of debt in order to fund our capital expenditure program. In addition, the passage of the TCJA will reduce cash flows we receive from our customers due to lower income taxes included in our prices. The reduction in cash flows may require us to raise additional debt resulting in higher interest expense. We believe increased interest expense 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 low by historical standards. We cannot predict to what extent these conditions will continue. See Note 10 of the Notes to Consolidated Financial Statements, "Long-Term Debt" and "Item 1A Risk

Factors" for additional information regarding the issuance of long-term debt.

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Customer Growth and Usage

Retail customer additions have been growing approximately 0.5% the past few years. With the numerous energy efficiency policy initiatives promulgated through federal, state and local governments, as well as industry initiatives, environmental regulations and the need to strengthen and modernize the grid, which will increase our prices, we believe customers will continue to adopt more energy efficiency and conservation measures, which will slow or possibly suppress the growth of demand for electricity.

2018 Outlook

In 2018, we expect to maintain our current business strategy and regulatory approach. Assuming normal weather, we expect 2018 retail electricity sales growth will be 0.5% or less.

In addition, we anticipate increased operating and maintenance and selling, general and administrative expenses. We also expect SPP transmission expense and property tax expense to continue to increase at a much higher rate than inflation. However, we believe this will have a minimal impact to our consolidated financial results since SPP transmission expense and property tax expense are offset with higher revenues pursuant to our regulatory mechanisms. We also anticipate incremental merger-related expenses. See Note 3 of the Notes to Consolidated Financial Statements, "Pending Merger," for additional information. To help fund our capital spending as provided under "—Future Cash Requirements" below, in 2018 we may issue long-term debt, and utilize short-term borrowings by issuing commercial paper until permanent financing is in place.

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 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. If we 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, 2017, we had recorded regulatory assets currently subject to recovery in future prices of approximately $784.9 million and regulatory liabilities of $1.1 billion, as discussed in greater detail in Note 4 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 GAAP.

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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, life expectancy and 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	$106,897	$ 8,970
	0.5% increase	(95,006)	(8,086)
Compensation	0.5% decrease	(21,448)	(3,904)
	0.5% increase	21,568	4,217
Rate of return on plan assets	0.5% decrease	—	4,212
	0.5% increase	—	(4,212)

(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	$8,170	$ 306
	0.5% increase	(7,649)	(311)
Rate of return on plan assets	0.5% decrease	—	576
	0.5% increase	—	(576)
Annual medical trend	1.0% decrease	142	21
	1.0% increase	(133)	(19)

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

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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 $76.7 million as of December 31, 2017 and $74.4 million as of December 31, 2016.

Income Taxes

We use the asset and liability method of accounting for income taxes. Under this method, we recognize deferred income 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 future tax benefits to the extent that realization of such benefits is more likely than not. With the passage of the Tax Cuts and Jobs Act (TCJA) in December 2017, we were required to remeasure deferred income tax assets and liabilities at the lower 21% corporate tax rate and defer the amount of excess deferred taxes previously collected from our customers to a regulatory liability, the majority of which will be amortized to income over a period generally corresponding to the life of our plant assets. 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 income tax assets to the extent capital losses, net 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 income 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. We believe the accounting associated with the passage of the TCJA is complete and we have therefore not recorded any provisional amounts in our consolidated financial statements. See Note 11 of the Notes to Consolidated Financial Statements, “Taxes,” for additional detail on our accounting for income taxes.

Asset Retirement Obligations

We have recognized legal obligations associated with the disposal of long-lived assets that result from the acquisition, construction, development or normal operation of such assets. Concurrent with the recognition of the liability, the estimated cost of the 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. 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 or an offset to a regulatory liability.

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, close ash landfills and dispose of polychlorinated biphenyl contaminated oil. ARO refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement may be conditional on a future event that may or may not be within the control of the entity. 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, 2017 and 2016, we have recorded AROs of $405.1 million and $324.0 million, respectively. For additional information on our legal AROs, see Note 15 of the Notes to Consolidated Financial Statements, “Asset Retirement Obligations.”

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Contingencies and Litigation

We and our subsidiaries are involved in various legal, environmental and regulatory proceedings, and we have estimated the probable cost for the resolution of these proceedings. 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 4, 14 and 16 of the Notes to Consolidated Financial Statements, "Rate Matters and Regulations," "Commitments and Contingencies" and "Legal Proceedings," respectively, for additional information.

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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 include lighting for public streets and highways, net of revenue subject to refund.

Wholesale: Sales of electricity to electric cooperatives, municipalities, other electric utilities and RTOs, the prices for which are either based on cost or prevailing market prices as prescribed by FERC authority. Revenues from these sales are either included in the retail energy cost adjustment or used in the determinations of base rates at the time of our next general rate review.

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.

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2017 Compared to 2016

Below we discuss our operating results for the year ended December 31, 2017, compared to the results for the year ended December 31, 2016. Significant changes in results of operations shown in the table immediately below are further explained in the descriptions that follow.

	Year Ended December 31,			
	2017	2016	Change	% Change
	(Dollars In Thousands, Except Per Share Amounts)			
REVENUES:				
Residential	$ 821,222	$ 838,998	$ (17,776)	(2.1)
Commercial	729,743	741,066	(11,323)	(1.5)
Industrial	423,620	413,298	10,322	2.5
Other retail	(28,551)	(15,013)	(13,538)	(90.2)
Total Retail Revenues	1,946,034	1,978,349	(32,315)	(1.6)
Wholesale	312,942	304,871	8,071	2.6
Transmission	279,446	253,713	25,733	10.1
Other	32,581	25,154	7,427	29.5
Total Revenues	2,571,003	2,562,087	8,916	0.3
OPERATING EXPENSES:				
Fuel and purchased power	541,535	509,496	32,039	6.3
SPP network transmission costs	247,882	232,763	15,119	6.5
Operating and maintenance	333,923	346,313	(12,390)	(3.6)
Depreciation and amortization	371,747	338,519	33,228	9.8
Selling, general and administrative	249,567	261,451	(11,884)	(4.5)
Taxes other than income tax	167,630	191,662	(24,032)	(12.5)
Total Operating Expenses	1,912,284	1,880,204	32,080	1.7
INCOME FROM OPERATIONS	658,719	681,883	(23,164)	(3.4)
OTHER INCOME (EXPENSE):				
Investment earnings	10,693	9,013	1,680	18.6
Other income	8,351	34,582	(26,231)	(75.9)
Other expense	(19,055)	(18,012)	(1,043)	(5.8)
Total Other (Expense) Income	(11)	25,583	(25,594)	(100.0)
Interest expense	171,001	161,726	9,275	5.7
INCOME BEFORE INCOME TAXES	487,707	545,740	(58,033)	(10.6)
Income tax expense	151,155	184,540	(33,385)	(18.1)
NET INCOME	336,552	361,200	(24,648)	(6.8)
Less: Net income attributable to noncontrolling interests	12,632	14,623	(1,991)	(13.6)
NET INCOME ATTRIBUTABLE TO WESTAR ENERGY, INC.	$ 323,920	$ 346,577	$ (22,657)	(6.5)
BASIC EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING ATTRIBUTABLE TO WESTAR ENERGY, INC.	$ 2.27	$ 2.43	$ (0.16)	(6.6)
DILUTED EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING ATTRIBUTABLE TO WESTAR ENERGY, INC.	$ 2.27	$ 2.43	$ (0.16)	(6.6)

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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, a non-GAAP measure, 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, 2017 and 2016.

	Year Ended December 31,			
	2017	2016	Change	% Change
	(Dollars In Thousands)			
Revenues	$2,571,003	$2,562,087	$8,916	0.3
Less: Fuel and purchased power expense	541,535	509,496	32,039	6.3
SPP network transmission costs	247,882	232,763	15,119	6.5
Gross Margin	$1,781,586	$1,819,828	$(38,242)	(2.1)

The following table reflects changes in electricity sales for the years ended December 31, 2017 and 2016. 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,			
	2017	2016	Change	% Change
	(Thousands of MWh)			
ELECTRICITY SALES:				
Residential	6,163	6,434	(271)	(4.2)
Commercial	7,368	7,544	(176)	(2.3)
Industrial	5,689	5,499	190	3.5
Other retail	73	77	(4)	(5.2)
Total Retail	19,293	19,554	(261)	(1.3)
Wholesale	10,346	8,299	2,047	24.7
Total	29,639	27,853	1,786	6.4

Gross margin decreased due primarily to lower retail sales. The lower retail sales were attributable primarily to more mild weather, which particularly impacts residential and commercial customers. There were approximately 13% fewer cooling degree days compared to 2016. Partially offsetting the impact of less favorable weather in 2017 was improved sales to industrial customers due partially to a few of our larger, lower margin chemical and oil customers who experienced improved global demand for their products as well as improved sales to the construction segment.

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Income from operations, which is calculated and presented in accordance with GAAP in our consolidated statements of income, is the most directly comparable measure to our presentation of gross margin. 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, 2017 and 2016.

	Year Ended December 31,			
	2017	2016	Change	% Change
	(Dollars In Thousands)			
Income from operations	$658,719	$681,883	$(23,164)	(3.4)
Plus: Operating and maintenance expense	333,923	346,313	(12,390)	(3.6)
Depreciation and amortization expense	371,747	338,519	33,228	9.8
Selling, general and administrative expense	249,567	261,451	(11,884)	(4.5)
Taxes other than income tax	167,630	191,662	(24,032)	(12.5)
Gross Margin	$1,781,586	$1,819,828	$(38,242)	(2.1)

Operating Expenses and Other Income and Expense Items

	Year Ended December 31,			
	2017	2016	Change	% Change
	(Dollars in Thousands)			
Operating and maintenance expense	$333,923	$346,313	$(12,390)	(3.6)

Operating and maintenance expense decreased due primarily to:

- lower transmission and distribution operating and maintenance costs of $8.6 million, due in part to higher grid resiliency costs in 2016 and receiving credit for assisting other utilities with mutual aid during an active hurricane season, which offset our operating and maintenance costs; and
- a $5.8 million decrease in nuclear operating and maintenance costs due primarily to receiving a legal settlement for Wolf Creek; and
- lower operating and maintenance costs at our coal fired plants of $4.9 million, due primarily to a planned outage at JEC in 2016; however;
- partially offsetting these decreases was an $8.8 million increase in operating and maintenance costs due to the start of operation of our Western Plains Wind Farm in March 2017.

	Year Ended December 31,			
	2017	2016	Change	% Change
	(Dollars in Thousands)			
Depreciation and amortization expense	$371,747	$338,519	$33,228	9.8

Depreciation and amortization expense increased due primarily to the start of Western Plains Wind Farm in March 2017.

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	Year Ended December 31,			
	2017	2016	Change	% Change
	(Dollars in Thousands)			
Selling, general and administrative expense	$249,567	$261,451	$(11,884)	(4.5)

Selling, general and administrative expense decreased due primarily to:

- our having recorded $7.1 million less for employee compensation that is at-risk to employees and payable only upon meeting pre-established operating and financial objectives; and
- a decrease in the allowance for uncollectible accounts of $1.4 million; and
- a decrease of $1.2 million in meter reading expenses due primarily to implementing the use of smart meters.

	Year Ended December 31,			
	2017	2016	Change	% Change
	(Dollars in Thousands)			
Taxes other than income tax	$167,630	$191,662	$(24,032)	(12.5)

Taxes other than income tax decreased due primarily to a $24.2 million decrease in property tax expense. This decrease was due to a decrease in amortization of the regulatory asset comprised of actual costs incurred for property taxes in the prior year in excess of amounts collected in our prices in the prior year. This decrease is mostly offset in retail revenues.

	Year Ended December 31,			
	2017	2016	Change	% Change
	(Dollars in Thousands)			
Other income	$8,351	$34,582	$(26,231)	(75.9)

Other income decreased due to our having recorded $19.5 million less in COLI benefits and a decrease in equity AFUDC of $9.6 million. Partially offsetting these decreases was an increase of $3.5 million related to the deconsolidation of the trust holding our 8% interest in JEC.

	Year Ended December 31,			
	2017	2016	Change	% Change
	(Dollars in Thousands)			
Interest expense	$171,001	$161,726	$9,275	5.7

Interest expense increased due primarily to an increase in interest expense on long-term debt of $4.9 million as a result of the issuance of first mortgage bonds (FMBs) in excess of retirements and a $4.4 million decrease in debt AFUDC.

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	Year Ended December 31,			
	2017	2016	Change	% Change
	(Dollars in Thousands)			
Income tax expense	$151,155	$184,540	$(33,385)	(18.1)

Income tax expense decreased due primarily to:

- an increase of $24.0 million in production tax credits, largely from placing the Western Plains Wind Farm in service; and
- a reduction in income tax expense of $22.9 million from lower income before income taxes; however,
- partially offsetting these decreases was an increase of approximately $12.2 million in income tax due to expensing excess net deferred income tax assets associated with the TCJA.

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2016 Compared to 2015

Below we discuss our operating results for the year ended December 31, 2016, compared to the results for the year ended December 31, 2015. Significant changes in results of operations shown in the table immediately below are further explained in the descriptions that follow.

	Year Ended December 31,			
	2016	2015	Change	% Change
	(Dollars In Thousands, Except Per Share Amounts)			
REVENUES:				
Residential	$ 838,998	$ 768,618	$ 70,380	9.2
Commercial	741,066	712,400	28,666	4.0
Industrial	413,298	400,687	12,611	3.1
Other retail	(15,013)	(17,155)	2,142	12.5
Total Retail Revenues	1,978,349	1,864,550	113,799	6.1
Wholesale	304,871	318,371	(13,500)	(4.2)
Transmission	253,713	241,835	11,878	4.9
Other	25,154	34,408	(9,254)	(26.9)
Total Revenues	2,562,087	2,459,164	102,923	4.2
OPERATING EXPENSES:				
Fuel and purchased power	509,496	561,065	(51,569)	(9.2)
SPP network transmission costs	232,763	229,043	3,720	1.6
Operating and maintenance	346,313	330,289	16,024	4.9
Depreciation and amortization	338,519	310,591	27,928	9.0
Selling, general and administrative	261,451	250,278	11,173	4.5
Taxes other than income tax	191,662	156,901	34,761	22.2
Total Operating Expenses	1,880,204	1,838,167	42,037	2.3
INCOME FROM OPERATIONS	681,883	620,997	60,886	9.8
OTHER INCOME (EXPENSE):				
Investment earnings	9,013	7,799	1,214	15.6
Other income	34,582	19,438	15,144	77.9
Other expense	(18,012)	(17,636)	(376)	(2.1)
Total Other Income	25,583	9,601	15,982	166.5
Interest expense	161,726	176,802	(15,076)	(8.5)
INCOME BEFORE INCOME TAXES	545,740	453,796	91,944	20.3
Income tax expense	184,540	152,000	32,540	21.4
NET INCOME	361,200	301,796	59,404	19.7
Less: Net income attributable to noncontrolling interests	14,623	9,867	4,756	48.2
NET INCOME ATTRIBUTABLE TO WESTAR ENERGY. INC.	$ 346,577	$ 291,929	$ 54,648	18.7
BASIC EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING ATTRIBUTABLE TO WESTAR ENERGY, INC.	$ 2.43	$ 2.11	$ 0.32	15.2
DILUTED EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING ATTRIBUTABLE TO WESTAR ENERGY, INC.	$ 2.43	$ 2.09	$ 0.34	16.3

Rate Review Agreement

In September 2015, the KCC issued an order in our state general rate review allowing us to adjust our prices to include, among other things, additional investment in La Cygne environmental upgrades and investment to extend the life of Wolf Creek. The new prices were effective late October 2015 and are expected to increase our annual retail revenues by approximately $78.3 million.

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Gross Margin

The following table summarizes our gross margin for the years ended December 31, 2016 and 2015.

	Year Ended December 31,			
	2016	2015	Change	% Change
	(Dollars In Thousands)			
Revenues	$2,562,087	$2,459,164	$102,923	4.2
Less: Fuel and purchased power expense	509,496	561,065	(51,569)	(9.2)
SPP network transmission costs	232,763	229,043	3,720	1.6
Gross Margin	$1,819,828	$1,669,056	$150,772	9.0

The following table reflects changes in electricity sales for the years ended December 31, 2016 and 2015. 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,			
	2016	2015	Change	% Change
	(Thousands of MWh)			
ELECTRICITY SALES:				
Residential	6,434	6,364	70	1.1
Commercial	7,544	7,500	44	0.6
Industrial	5,499	5,502	(3)	(0.1)
Other retail	77	84	(7)	(8.3)
Total Retail	19,554	19,450	104	0.5
Wholesale	8,299	8,492	(193)	(2.3)
Total	27,853	27,942	(89)	(0.3)

Gross margin increased due primarily to higher retail prices, which increased approximately 6%. Gross margin also increased slightly due to weather that was modestly favorable relative to 2015. During 2016, there were approximately 10% more cooling degree days compared to 2015.

Income from operations, which is calculated and presented in accordance with GAAP in our consolidated statements of income, is the most directly comparable measure to our presentation of gross margin. 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, 2016 and 2015.

	Year Ended December 31,			
	2016	2015	Change	% Change
	(Dollars In Thousands)			
Income from operations	$681,883	$620,997	$60,886	9.8
Plus: Operating and maintenance expense	346,313	330,289	16,024	4.9
Depreciation and amortization expense	338,519	310,591	27,928	9.0
Selling, general and administrative expense	261,451	250,278	11,173	4.5
Taxes other than income tax	191,662	156,901	34,761	22.2
Gross margin	$1,819,828	$1,669,056	$150,772	9.0

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Operating Expenses and Other Income and Expense Items

	Year Ended December 31,			
	2016	2015	Change	% Change
	(Dollars in Thousands)			
Operating and maintenance expense	$346,313	$330,289	$16,024	4.9

Operating and maintenance expense increased due principally to:

- higher operating and maintenance costs at our coal fired plants of $14.1 million, due primarily to scheduled outages;
- higher transmission and distribution operating and maintenance costs of $4.3 million due partially to improving long-term reliability; and
- higher decommissioning costs of $3.0 million for Wolf Creek, which is offset in retail revenues; however,
- partially offsetting these increases was a $9.8 million decrease in operating and maintenance costs related to our having retired three generating units in late 2015.

	Year Ended December 31,			
	2016	2015	Change	% Change
	(Dollars in Thousands)			
Depreciation and amortization expense	$338,519	$310,591	$27,928	9.0

Depreciation and amortization expense increased due primarily to air quality control additions at La Cygne.

	Year Ended December 31,			
	2016	2015	Change	% Change
	(Dollars in Thousands)			
Selling, general and administrative expense	$261,451	$250,278	$11,173	4.5

Selling, general and administrative expense increased due primarily to:

- incurring $10.2 million of merger-related expenses in 2016;
- an increase in the allowance for uncollectible accounts of $3.5 million; and
- an increase of $2.7 million in outside services related principally to technology services; however,
- partially offsetting these increases was lower employee benefit costs of $7.6 million due primarily to reduced post-retirement medical costs.

	Year Ended December 31,			
	2016	2015	Change	% Change
	(Dollars in Thousands)			
Taxes other than income tax	$191,662	$156,901	$34,761	22.2

Taxes other than income tax increased due primarily to a $36.1 million increase in property tax expense, which is mostly offset in retail revenues.

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	Year Ended December 31,			
	2016	2015	Change	% Change
	(Dollars in Thousands)			
Other income	$34,582	$19,438	$15,144	77.9

Other income increased due primarily to an increase in equity AFUDC of $9.6 million and our having recorded $7.2 million more in COLI benefits.

	Year Ended December 31,			
	2016	2015	Change	% Change
	(Dollars in Thousands)			
Interest expense	$161,726	$176,802	$(15,076)	(8.5)

Interest expense decreased due primarily to a $6.5 million increase in debt AFUDC, a $5.7 million decrease in interest on long-term debt of VIEs due to refinancing long-term debt of the La Cygne VIE and a $4.8 million decrease in interest expense on long-term debt due to refinancing long-term debt at lower rates.

	Year Ended December 31,			
	2016	2015	Change	% Change
	(Dollars in Thousands)			
Income tax expense	$184,540	$152,000	$32,540	21.4

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, 2017, compared to December 31, 2016.

	As of December 31,			
	2017	2016	Change	% Change
	(Dollars in Thousands)			
Property, plant and equipment, net	$9,553,755	$9,248,359	$305,396	3.3

Property, plant and equipment, net of accumulated depreciation, increased due primarily to the construction of Western Plains Wind Farm and plant additions for capital improvements to improve long-term reliability.

	As of December 31,			
	2017	2016	Change	% Change
	(Dollars in Thousands)			
Property, plant and equipment of variable interest entities, net	$176,279	$257,904	$(81,625)	(31.6)

Property, plant and equipment of variable interest entities, net of accumulated depreciation, decreased $72.9 million related primarily to the deconsolidation of the trust holding our 8% interest in JEC.

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	As of December 31,			
	2017	2016	Change	% Change
	(Dollars in Thousands)			
Regulatory assets	$784,899	$879,862	$(94,963)	(10.8)
Regulatory liabilities	1,105,576	239,453	866,123	361.7
Net regulatory (liabilities) assets	$(320,677)	$640,409	$(961,086)	(150.1)

Total regulatory assets decreased due primarily to the following items:

- a $124.0 million decrease in amounts due from customers for future income taxes due primarily to changes in deferred income taxes caused by TCJA;
- a $13.3 million decrease in amounts deferred for Wolf Creek refueling and maintenance outages; and
- a $11.7 million decrease in amounts to be collected from our customers for the deferred cost of fuel and purchased power; however,
- partially offsetting these decreases was spending $30.8 million more than collected for the cost to remove retired plant assets;
- a $23.0 million increase in our unrecovered investment in analog meters; and
- a $12.8 million increase in deferred employee benefit costs.

Total regulatory liabilities increased due primarily to the following items:

- a $845.2 million increase in amounts due to customers for future income taxes due primarily to changes in deferred income taxes caused by TCJA;
- a $37.0 million increase in the fair value of the NDT; and
- a $11.2 million increase in amounts recognized in setting our prices in excess of actual pension and post-retirement expense; however,
- partially offsetting these increases was $15.5 million for accretion and depreciation related to the Wolf Creek ARO; and
- our spending $5.7 million more than collected for the cost to remove retired plant assets.

See Note 11 of the Consolidated Financial Statements, “Taxes,” for additional information on the TCJA.

	As of December 31,			
	2017	2016	Change	% Change
	(Dollars in Thousands)			
Short-term debt	$275,700	$366,700	$(91,000)	(24.8)

Short-term debt decreased due primarily to Westar Energy issuing $300.0 million in principal amount of FMBs, the proceeds for which were used to repay a portion of commercial paper borrowings, and retiring $125.0 million in principal amount of FMBs. See Note 10 of the Notes to Consolidated Financial Statements, "Long-Term Debt," for additional information.

	As of December 31,			
	2017	2016	Change	% Change
	(Dollars in Thousands)			
Current maturities of long-term debt	$—	$125,000	$(125,000)	(100.0)
Long-term debt, net	3,687,555	3,388,670	298,885	8.8
Total long-term debt	$3,687,555	$3,513,670	$173,885	4.9

Total long-term debt increased due primarily to Westar Energy issuing $300.0 million in principal amount of FMBs and retiring $125.0 million in principal amounts of FMBs. See Note 10 of the Notes to Consolidated Financial Statements, "Long-Term Debt," for additional information.

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	As of December 31,			
	2017	2016	Change	% Change
	(Dollars in Thousands)			
Current maturities of long-term debt of variable interest entities	$28,534	$26,842	$1,692	6.3
Long-term debt of variable interest entities	81,433	111,209	(29,776)	(26.8)
Total long-term debt of variable interest entities	$109,967	$138,051	$(28,084)	(20.3)

Total long-term debt of variable interest entities decreased due primarily to the VIE that holds the La Cygne leasehold interests having made principal payments totaling $26.8 million. See Note 18 of the Notes to Consolidated Financial Statements, "Variable Interest Entities," for additional information.

	As of December 31,			
	2017	2016	Change	% Change
	(Dollars in Thousands)			
Deferred income tax liabilities	$815,743	$1,752,776	$(937,033)	(53.5)

Deferred income tax liabilities decreased primarily due to adjusting deferred taxes to reflect the new federal corporate income tax rate of 21% as prescribed in the TCJA.

	As of December 31,			
	2017	2016	Change	% Change
	(Dollars in Thousands)			
Accrued employee benefits	$541,364	$512,412	$28,952	5.7

Accrued employee benefits increased due primarily to higher pension and post-retirement benefit obligations as a result of a decrease in the discount rates used to calculate our and Wolf Creek’s pension benefit obligations.

	As of December 31,			
	2017	2016	Change	% Change
	(Dollars in Thousands)			
Asset retirement obligations	$379,989	$323,951	$56,038	17.3

AROs increased due primarily to revisions for asbestos and nuclear decommissioning of $28.8 million and $19.4 million, respectively, and a new obligation estimated at $13.5 million related to Western Plains Wind Farm. See Note 14 of the Notes to Consolidated Financial Statements, “Commitments and Contingencies,” and Note 15 of the Notes to Consolidated Financial Statements, “Asset Retirement Obligations,” for additional information.

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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, payroll 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. In 2018, we expect to continue our capital spending program and plan to contribute to our pension trust. We continue to believe that we will have the ability to pay dividends. Although the agreement and plan of merger with Great Plains Energy contains customary restrictions on our ability to raise capital and pay dividends, we do not believe these restrictions will materially adversely impact our liquidity or ability to pay dividends in 2018. Uncertainties affecting our ability to meet cash requirements include, among others, factors affecting revenues described in "Item 1A. Risk Factors" and "—Operating Results" above, economic conditions, regulatory actions, compliance with environmental regulations and conditions in the capital markets. For additional information on our future cash requirements, see "—Future Cash Requirements" below.

Impact of TCJA

The passage of the TCJA in December 2017 will reduce our internally generated cash flows and may adversely impact the manner in which our credit rating is evaluated. Specifically, we expect a degradation in our funds from operations to debt ratio of approximately 100 to 200 basis points.

Capital Structure

As of December 31, 2017 and 2016, our capital structure, excluding short-term debt, was as follows:

	As of December 31,	
	2017	2016
Common equity	51%	51%
Noncontrolling interests	<0%	<1%
Long-term debt, including VIEs	49%	49%

Short-Term Borrowings

Westar Energy maintains 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 and cannot exceed the capacity under 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 redeem debt on an interim basis, for working capital and/or for other general corporate purposes. As of February 14, 2018, Westar Energy had $285.3 million of commercial paper issued and outstanding.

Westar Energy has two revolving credit facilities in the amounts of $730.0 million and $270.0 million. The $730.0 million facility will expire in September 2019, $20.7 million of which expired in September 2017. In December 2017, Westar Energy extended the term of the $270.0 million facility by one year to terminate in February 2019. 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 14, 2018, no amounts were borrowed and $11.6 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.

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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, 2017, our ratio was 51%. See Note 9 of the Notes to Consolidated Financial Statements, “Short-Term Debt,” for additional information regarding our short-term borrowings.

Long-Term Debt Financing

As of December 31, 2017, we had $121.9 million of variable rate, tax-exempt bonds outstanding. While the interest rates for these bonds have been low, we continue to monitor the credit markets and evaluate our options with respect to these bonds.

In March 2017, Westar Energy issued $300.0 million in principal amount of FMBs bearing a stated interest at 3.10% maturing April 2027.

In January 2017, Westar Energy retired $125.0 million in principal amount of FMBs bearing a stated interest at 5.15% maturing January 2017.

The Westar Energy and KGE mortgages each contain provisions restricting the amount of FMBs that can be issued by each entity. We must comply with such restrictions prior to the issuance of additional FMBs 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 FMBs 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 FMBs outstanding after giving effect to the proposed issuance. As of December 31, 2017, approximately $929.7 million principal amount of additional FMBs could be issued under the most restrictive provisions in the mortgage, except in connection with certain refundings.

Under the KGE mortgage, the amount of FMBs authorized is limited to a maximum of $3.5 billion and the issuance of bonds is subject to limitations based on the amount of bondable property additions. In addition, the mortgage prohibits additional FMBs 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 FMBs outstanding after giving effect to the proposed issuance. As of December 31, 2017, approximately $1.5 billion principal amount of additional KGE FMBs could be issued under the most restrictive provisions in the mortgage, except in connection with certain refundings.

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, 2017.

Impact of Credit Ratings on Debt Financing

Moody’s Investors Service (Moody’s) and Standard & Poor’s Ratings Services (S&P) 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.

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Factors that impact our credit ratings include a combination of objective and subjective criteria. Objective criteria include typical financial ratios, such as funds from operations to total debt and operating cash flow to 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.

As of February 14, 2018, 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	A-2	Positive

(a) In July 2017, following the public announcement of the amended and restated agreement and plan of merger with Great Plains Energy, S&P revised its outlook for Westar Energy and KGE to positive from negative, pending the outcome of the merger.

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, 2017, Westar Energy had 142.1 million shares issued and outstanding.

Summary of Cash Flows

	Year Ended December 31,		
	2017	2016	2015
	(In Thousands)		
Cash flows from (used in):			
Operating activities	$912,438	$822,420	$715,850
Investing activities	(780,434)	(1,012,760)	(649,704)
Financing activities	(131,638)	190,175	(67,471)
Net increase (decrease) in cash and cash equivalents	$366	$(165)	$(1,325)

Cash Flows from Operating Activities

Cash flows from operating activities increased $90.0 million in 2017 compared to 2016 due principally to our having received $43.9 million more for wholesale power sales and transmission services, paid $26.3 million less for coal and natural gas, received a $13.0 million refund for income taxes in 2017, compared to having paid $13.0 million in 2016, and received $13.6 million more from retail customers. Partially offsetting these increases was our having received $20.2 million less in COLI death proceeds, paid $16.4 million more for purchase power and transmission services and paid $12.0 million more for interest.

Cash flows from operating activities increased $106.6 million in 2016 compared to 2015 due principally to our having paid $92.8 million less for coal and natural gas and $27.0 million less for interest, while having received $91.2 million more from retail customers. Partially offsetting these increases was our having received $32.7 million less for wholesale power sales and transmission services, while having paid $20.2 million more for purchase power and transmission services and $13.5 million more in income tax payments.

Cash Flows used in Investing Activities

Cash flows used in investing activities decreased $232.3 million in 2017 compared to 2016 due primarily to our having invested $322.3 million less in additions to property, plant and equipment primarily related to the construction of Western Plains Wind Farm partially offset by our having received $91.3 million less from our investment in COLI.

Cash flows used in investing activities increased $363.1 million in 2016 compared to 2015 due primarily to our having invested $386.7 million more in additions to property, plant and equipment primarily related to the construction of Western Plains Wind Farm. Partially offsetting this increase was our having received $25.9 million more from our investment in COLI.

Cash Flows from (used in) Financing Activities

Cash flows from financing activities decreased $321.8 million in 2017 compared to 2016. The decrease was due principally to our having issued $207.5 million less in commercial paper, issued $162.0 million less in long-term debt of VIEs, issued $100.1 million less in long-term debt, redeemed $75.0 million more in long-term debt and paid $18.8 million more in dividends. Partially offsetting these decreases was our having redeemed $163.5 million less in long-term debt of VIEs and repaid $88.3 million less for borrowings against the cash surrender value of COLI.

Cash flows from financing activities increased $257.6 million in 2016 compared to 2015. The increase was due principally to our having redeemed $585.9 million less in long-term debt, issued $162.0 million more in long-term debt of VIEs and issued $123.5 million more in commercial paper. Partially offsetting these increases was our having issued $255.6 million less in common stock, redeemed $162.4 million more in long-term debt of VIEs, issued $147.6 million less in long-term debt, repaid $24.7 million more for borrowings against the cash surrender value of COLI and paid $18.2 million more in dividends.

Future Cash Requirements

Our business requires significant capital investments. Through 2020, 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 to develop 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.

Capital expenditures for 2017 and anticipated capital expenditures, including costs of removal, for 2018 through 2020 are shown in the following table.

	Actual	Projected		
	2017	2018	2019	2020
	(In Thousands)			
Generation:				
Replacements and other	$151,886	$186,500	$166,800	$162,000
Environmental	22,279	22,400	5,100	7,400
Wind development	39,289	5,900	9,300	6,000
Nuclear fuel	41,649	21,400	26,300	44,700
Transmission	240,396	245,300	254,900	247,200
Distribution	208,478	195,500	190,100	186,400
Other	60,668	83,000	104,500	96,300
Total capital expenditures	$764,645	$760,000	$757,000	$750,000

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 changes following the closing of the proposed merger with Great Plains Energy, 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 material changes in actual costs.

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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, 2017, are as follows.

Year	Long-term debt	Long-term debt of VIEs
	(In Thousands)	
2018	$—	$ 28,534
2019	300,000	30,337
2020	250,000	32,254
2021	—	18,842
2022	—	—
Thereafter	3,176,940	—
Total maturities	$3,726,940	$ 109,967

Pension Obligation

The amount we contribute to our pension plan for future periods is not yet known, however, in general 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 $24.3 million to our pension trust in 2017 and $20.2 million in 2016. We expect to contribute approximately $32.4 million in 2018. In 2017 and 2016, we also funded $12.0 million and $14.8 million, respectively, of Wolf Creek’s pension plan contributions. In 2018, we plan to contribute $8.9 million to fund Wolf Creek’s pension plan contributions. See Notes 12 and 13 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

We 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, 2017.

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.

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Contractual Cash Obligations

The following table summarizes the projected future cash payments for our contractual obligations existing as of December 31, 2017.

	Total	2018	2019 - 2020	2021 - 2022	Thereafter
	(In Thousands)				
Long-term debt (a)	$3,726,940	$—	$550,000	$ —	$3,176,940
Long-term debt of VIEs (a)	109,967	28,534	62,591	18,842	—
Interest on long-term debt (b)	2,690,450	159,357	288,564	253,014	1,989,515
Interest on long-term debt of VIEs	4,948	2,295	2,427	226	—
Long-term debt, including interest	6,532,305	190,186	903,582	272,082	5,166,455
Pension and post-retirement benefit expected contributions (c)	41,900	41,900	—	—	—
Capital leases (d)	76,104	6,433	11,069	8,791	49,811
Operating leases (e)	58,659	18,132	22,674	11,953	5,900
Fossil fuel (f)	582,249	172,043	353,600	18,180	38,426
Nuclear fuel (g)	199,813	4,207	72,503	42,427	80,676
Unconditional purchase obligations	283,345	257,544	22,629	3,172	—
Total contractual obligations (h)	$7,774,375	$690,445	$1,386,057	$ 356,605	$5,341,268

(a) See Note 10 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, 2017.
(c) Our contribution amounts for future periods are not yet known. See Notes 12 and 13 of the Notes to Consolidated Financial Statements, "Employee Benefit Plans" and "Wolf Creek Employee Benefit Plans," for additional information regarding 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) Coal and natural gas commodity and transportation contracts.
(g) Uranium concentrates, conversion, enrichment and fabrication.
(h) We have $1.8 million of unrecognized income tax benefits 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, 2017.

OTHER INFORMATION

Changes in Prices

See Note 4 of the Notes to Consolidated Financial Statements, "Rate Matters and Regulation," for information on our prices.

Wolf Creek Outage

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 refueling and maintenance outages. In the fall of 2016, Wolf Creek underwent a planned refueling and maintenance outage. Our share of the outage costs was approximately $24.2

million. In early 2018, Wolf Creek is scheduled to undergo a planned maintenance outage. We expect our share of the outage to be approximately $21.8 million.

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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 12 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 $4.7 million as of December 31, 2017, and, absent the merger, 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 $3.6 million as of December 31, 2017, and, absent the merger, we expect to recognize these costs over a remaining weighted-average period of 1.6 years. Upon consummation of the merger, all unrecognized compensation costs for outstanding RSU awards will be expensed on our income statement.

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 and the amount of electricity generated from our wind farms. 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.

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One way 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 portfolio VaR amounts for 2017 and 2016 were as follows:

	2017	2016
	(In Thousands)	
High	$ 273	$ 644
Low	—	123
Average	54	292

Interest Rate Risk

We have entered into numerous fixed and variable rate debt obligations. For details, see Note 10 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 $426.2 million of variable rate debt and current maturities of fixed rate debt as of December 31, 2017. A 100 basis point change in interest rates applicable to this debt would impact income before income taxes on an annualized basis by approximately $4.2 million. As of December 31, 2017, 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, 2017, investments in the NDT were allocated 51% to equity securities, 29% to debt securities, 6% to combination debt/equity/other securities, 9% to alternative investments, 5% to real estate securities and less than 1% to cash equivalents. As of December 31, 2017 and 2016, the fair value of the NDT investments was $237.1 million and $200.1 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 $23.7 million decrease in the value of the NDT as of December 31, 2017.

We also maintain a trust to fund non-qualified retirement benefits. As of December 31, 2017, investments in the trust were comprised of 80% debt securities, 20% combination debt/equity/other securities, and less than 1% cash equivalents. The fair value of the investments in this trust was $34.3 million as of December 31, 2017, and $34.5

million as of December 31, 2016. 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 $3.4 million decrease in the value of the trust as of December 31, 2017.

By maintaining diversified portfolios of securities, we seek to optimize 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

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.

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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, 2017. In making this assessment, we used the criteria set forth in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the assessment, we concluded that, as of December 31, 2017, 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.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
To the shareholders and the Board of Directors of Westar Energy, Inc.
Opinion on Internal Control over Financial Reporting
We have audited the internal control over financial reporting of Westar Energy, Inc. and subsidiaries (the "Company") as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework (2013) issued by COSO.
We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2017, of the Company and our report dated February 21, 2018 expressed an unqualified opinion on those financial statements.
Basis for Opinion
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 are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.
We conducted our audit in accordance with the standards of the PCAOB. 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.
Definition and Limitations of Internal Control over Financial Reporting
A company's internal control over financial reporting is a process designed 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 its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Deloitte & Touche LLP

Kansas City, Missouri
February 21, 2018

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
To the shareholders and the Board of Directors of Westar Energy, Inc.

Opinion on the Financial Statements
We have audited the accompanying consolidated balance sheets of Westar Energy, Inc. and subsidiaries (the "Company") as of December 31, 2017 and 2016, the related consolidated statements of income, changes in equity, and cash flows for each of the three years in the period ended December 31, 2017, and the related notes and the schedule listed in the Index at Item 15 (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with the accounting principles generally accepted in the United States of America.
We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 21, 2018, expressed an unqualified opinion on the Company's internal control over financial reporting.
Basis for Opinion
These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.
We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Deloitte & Touche LLP

Kansas City, Missouri
February 21, 2018

We have served as the Company's auditor since 2002.

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

	As of December 31,	
	2017	2016
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$3,432	$3,066
Accounts receivable, net of allowance for doubtful accounts of $6,716 and $6,667, respectively	290,652	288,579
Fuel inventory and supplies	293,562	300,125
Taxes receivable	—	13,000
Prepaid expenses	16,425	16,528
Regulatory assets	99,544	117,383
Other	23,435	29,701
Total Current Assets	727,050	768,382
PROPERTY, PLANT AND EQUIPMENT, NET	9,553,755	9,248,359
PROPERTY, PLANT AND EQUIPMENT OF VARIABLE INTEREST ENTITIES, NET	176,279	257,904
OTHER ASSETS:		
Regulatory assets	685,355	762,479
Nuclear decommissioning trust	237,102	200,122
Other	244,827	249,828
Total Other Assets	1,167,284	1,212,429
TOTAL ASSETS	$11,624,368	$11,487,074
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Current maturities of long-term debt	$—	$125,000
Current maturities of long-term debt of variable interest entities	28,534	26,842
Short-term debt	275,700	366,700
Accounts payable	204,186	220,522
Accrued dividends	53,830	52,885
Accrued taxes	87,727	85,729
Accrued interest	72,693	72,519
Regulatory liabilities	11,602	15,760
Other	89,445	81,236
Total Current Liabilities	823,717	1,047,193
LONG-TERM LIABILITIES:		
Long-term debt, net	3,687,555	3,388,670
Long-term debt of variable interest entities, net	81,433	111,209
Deferred income taxes	815,743	1,752,776
Unamortized investment tax credits	257,093	210,654
Regulatory liabilities	1,093,974	223,693
Accrued employee benefits	541,364	512,412
Asset retirement obligations	379,989	323,951
Other	83,063	83,326
Total Long-Term Liabilities	6,940,214	6,606,691
COMMITMENTS AND CONTINGENCIES (See Notes 14 and 16)		
EQUITY:		
Westar Energy, Inc. Shareholders' Equity:		

Common stock, par value $5 per share; authorized 275,000,000 shares; issued and outstanding 142,094,275 shares and 141,791,153 shares, respective to each date	710,471	708,956
Paid-in capital	2,024,396	2,018,317
Retained earnings	1,173,255	1,078,602
Total Westar Energy, Inc. Shareholders' Equity	3,908,122	3,805,875
Noncontrolling Interests	(47,685)	27,315
Total Equity	3,860,437	3,833,190
TOTAL LIABILITIES AND EQUITY	$11,624,368	$11,487,074

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

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

	Year Ended December 31,		
	2017	2016	2015
REVENUES	$2,571,003	$2,562,087	$2,459,164
OPERATING EXPENSES:			
Fuel and purchased power	541,535	509,496	561,065
SPP network transmission costs	247,882	232,763	229,043
Operating and maintenance	333,923	346,313	330,289
Depreciation and amortization	371,747	338,519	310,591
Selling, general and administrative	249,567	261,451	250,278
Taxes other than income tax	167,630	191,662	156,901
Total Operating Expenses	1,912,284	1,880,204	1,838,167
INCOME FROM OPERATIONS	658,719	681,883	620,997
OTHER INCOME (EXPENSE):			
Investment earnings	10,693	9,013	7,799
Other income	8,351	34,582	19,438
Other expense	(19,055)	(18,012)	(17,636)
Total Other (Expense) Income	(11)	25,583	9,601
Interest expense	171,001	161,726	176,802
INCOME BEFORE INCOME TAXES	487,707	545,740	453,796
Income tax expense	151,155	184,540	152,000
NET INCOME	336,552	361,200	301,796
Less: Net income attributable to noncontrolling interests	12,632	14,623	9,867
NET INCOME ATTRIBUTABLE TO WESTAR ENERGY, INC.	$323,920	$346,577	$291,929
BASIC AND DILUTED EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING ATTRIBUTABLE TO WESTAR ENERGY (see Note 2):			
Basic earnings per common share	$2.27	$2.43	$2.11
Diluted earnings per common share	$2.27	$2.43	$2.09
AVERAGE EQUIVALENT COMMON SHARES OUTSTANDING	142,463,831	142,067,558	137,957,515
DIVIDENDS DECLARED PER COMMON SHARE	$1.60	$1.52	$1.44

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

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

	Year Ended December 31,		
	2017	2016	2015
CASH FLOWS FROM (USED IN) OPERATING ACTIVITIES:			
Net income	$336,552	$361,200	$301,796
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	371,747	338,519	310,591
Amortization of nuclear fuel	32,167	26,714	26,974
Amortization of deferred regulatory gain from sale leaseback	(5,495)	(5,495)	(5,495)
Gain on lease modification	(3,500)	—	—
Amortization of corporate-owned life insurance	20,601	18,042	19,850
Non-cash compensation	8,985	9,353	8,345
Net deferred income taxes and credits	149,568	185,229	151,332
Allowance for equity funds used during construction	(1,996)	(11,630)	(2,075)
Payments for asset retirement obligations	(16,026)	(5,372)	(1,553)
Changes in working capital items:			
Accounts receivable	(2,073)	(30,294)	9,042
Fuel inventory and supplies	7,182	1,790	(53,263)
Prepaid expenses and other	64,744	(7,431)	(23,145)
Accounts payable	10,023	(8,149)	6,636
Accrued taxes	9,155	(5,942)	13,073
Other current liabilities	(118,018)	(86,359)	(80,396)
Changes in other assets	29,295	18,872	3,752
Changes in other liabilities	19,527	23,373	30,386
Cash Flows from Operating Activities	912,438	822,420	715,850
CASH FLOWS FROM (USED IN) INVESTING ACTIVITIES:			
Additions to property, plant and equipment	(764,645)	(1,086,970)	(700,228)
Purchase of securities - trusts	(41,033)	(46,581)	(37,557)
Sale of securities - trusts	41,245	47,026	37,930
Investment in corporate-owned life insurance	(13,875)	(14,648)	(14,845)
Proceeds from investment in corporate-owned life insurance	1,420	92,677	66,794
Investment in affiliated company	—	(655)	(575)
Other investing activities	(3,546)	(3,609)	(1,223)
Cash Flows used in Investing Activities	(780,434)	(1,012,760)	(649,704)
CASH FLOWS FROM (USED IN) FINANCING ACTIVITIES:			
Short-term debt, net	(91,328)	116,162	(7,300)
Proceeds from long-term debt	296,215	396,290	543,881
Proceeds from long-term debt of variable interest entities	—	162,048	—
Retirements of long-term debt	(125,000)	(50,000)	(635,891)
Retirements of long-term debt of variable interest entities	(26,840)	(190,357)	(27,933)
Repayment of capital leases	(3,530)	(3,104)	(2,591)
Borrowings against cash surrender value of corporate-owned life insurance	55,094	57,850	59,431
Repayment of borrowings against cash surrender value of corporate-owned life insurance	(1,008)	(89,284)	(64,593)
Issuance of common stock	659	2,439	257,998
Distributions to shareholders of noncontrolling interests	(5,760)	(2,550)	(1,076)
Cash dividends paid	(223,117)	(204,340)	(186,120)

Other financing activities	(7,023)	(4,979)	(3,277)
Cash Flows (used in) from Financing Activities	(131,638)	190,175	(67,471)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	366	(165)	(1,325)
CASH AND CASH EQUIVALENTS:			
Beginning of period	3,066	3,231	4,556
End of period	$3,432	$3,066	$3,231

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

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

	Westar Energy, Inc. Shareholders					
	Common stock shares	Common stock	Paid-in capital	Retained earnings	Non-controlling interests	Total equity
Balance as of December 31, 2014	131,687,454	$658,437	$1,781,120	$855,299	$ 6,451	$3,301,307
Net income	—	—	—	291,929	9,867	301,796
Issuance of stock	9,249,986	46,250	211,748	—	—	257,998
Issuance of stock for compensation and reinvested dividends	415,986	2,080	8,373	—	—	10,453
Tax withholding related to stock compensation	—	—	(3,277)	—	—	(3,277)
Dividends declared on common stock ($1.44 per share)	—	—	—	(201,398)	—	(201,398)
Stock compensation expense	—	—	8,250	—	—	8,250
Tax benefit on stock compensation	—	—	1,307	—	—	1,307
Distributions to shareholders of noncontrolling interests	—	—	—	—	(1,076)	(1,076)
Other	—	—	(3,397)	—	—	(3,397)
Balance as of December 31, 2015	141,353,426	706,767	2,004,124	945,830	15,242	3,671,963
Net income	—	—	—	346,577	14,623	361,200
Issuance of stock	48,101	241	2,198	—	—	2,439
Issuance of stock for compensation and reinvested dividends	389,626	1,948	7,737	—	—	9,685
Tax withholding related to stock compensation	—	—	(4,979)	—	—	(4,979)
Dividends declared on common stock ($1.52 per share)	—	—	—	(217,131)	—	(217,131)
Stock compensation expense	—	—	9,237	—	—	9,237
Distributions to shareholders of noncontrolling interests	—	—	—	—	(2,550)	(2,550)
Cumulative effect of accounting change - stock compensation	—	—	—	3,326	—	3,326
Balance as of December 31, 2016	141,791,153	708,956	2,018,317	1,078,602	27,315	3,833,190
Net income	—	—	—	323,920	12,632	336,552
Issuance of stock	12,131	61	598	—	—	659
Issuance of stock for compensation and reinvested dividends	290,991	1,454	3,635	—	—	5,089
Tax withholding related to stock compensation	—	—	(7,023)	—	—	(7,023)
Dividends declared on common stock ($1.60 per share)	—	—	—	(229,267)	—	(229,267)
Stock compensation expense	—	—	8,869	—	—	8,869
Deconsolidation of noncontrolling interests	—	—	—	—	(81,872)	(81,872)

Distributions to shareholders of noncontrolling interests	—	—	—	—	(5,760)	(5,760)
Balance as of December 31, 2017	142,094,275	$710,471	$2,024,396	$1,173,255	$ (47,685)	$3,860,437

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 708,000 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 generally accepted accounting principles (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 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 4, "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.

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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,	
	2017	2016
	(In Thousands)	
Fuel inventory	$94,039	$107,086
Supplies	199,523	193,039
Fuel inventory and supplies	$293,562	$300,125

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,		
	2017	2016	2015
	(Dollars In Thousands)		
Borrowed funds	$5,605	$9,964	$3,505
Equity funds	1,996	11,630	2,075
Total	$7,601	$21,594	$5,580
Average AFUDC Rates	2.3 %	4.2 %	2.7 %

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 2017, 2.4% in 2016 and 2.5% in 2015.

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 67
Distribution facilities	22 to 68
Other	5 to 30

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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. The accumulated amortization of nuclear fuel in the reactor was $72.2 million as of December 31, 2017, and $40.0 million as of December 31, 2016. The cost of nuclear fuel charged to fuel and purchased power expense was $32.2 million in 2017, $26.8 million in 2016 and $27.3 million in 2015.

Cash Surrender Value of Life Insurance

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

	As of December 31,	
	2017	2016
	(In Thousands)	
Cash surrender value of policies	$1,320,695	$1,267,349
Borrowings against policies	(1,189,212)	(1,137,360)
Corporate-owned life insurance, net	$131,483	$129,989

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 $76.7 million as of December 31, 2017, and $74.4 million as of December 31, 2016 within accounts receivable.

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 income 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 future tax benefits to the extent that realization of such benefits is more likely than not. With the passage of the Tax Cuts and Jobs Act (TCJA) in December 2017, we were required to remeasure deferred income tax assets and liabilities at the lower 21% corporate tax rate and defer the amount of excess deferred taxes previously collected from our customers to a regulatory liability, the majority of which will be amortized to income over a period generally corresponding to the life of our plant assets. 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 income tax assets to the extent capital losses, net 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 income tax asset.

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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 11, "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).

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 issuable common shares resulting from our forward sale agreements, if any, 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,		
	2017	2016	2015
	(Dollars In Thousands, Except Per Share Amounts)		
Net income	$336,552	$ 361,200	$ 301,796
Less: Net income attributable to noncontrolling interests	12,632	14,623	9,867
Net income attributable to Westar Energy, Inc.	323,920	346,577	291,929
Less: Net income allocated to RSUs	584	714	646
Net income allocated to common stock	$323,336	$ 345,863	$ 291,283
Weighted average equivalent common shares outstanding – basic	142,463,831	142,067,558	137,957,515
Effect of dilutive securities:			
RSUs	96,363	407,123	299,198
Forward sale agreements	—	—	1,021,510
Weighted average equivalent common shares outstanding – diluted (a)	142,560,194	142,474,681	139,278,223
Earnings per common share, basic	$2.27	$ 2.43	$ 2.11
Earnings per common share, diluted	$2.27	$ 2.43	$ 2.09

(a) For the years ended December 31, 2017, 2016 and 2015, we had no antidilutive securities.

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Supplemental Cash Flow Information

	Year Ended December 31,		
	2017	2016	2015
	(In Thousands)		
CASH PAID FOR (RECEIVED FROM):			
Interest on financing activities, net of amount capitalized	$153,905	$139,029	$161,484
Interest on financing activities of VIEs	3,061	5,846	10,430
Income taxes, net of refunds	(12,736)	13,103	(410)
NON-CASH INVESTING TRANSACTIONS:			
Property, plant and equipment additions	158,780	151,474	105,169
Deconsolidation of property, plant and equipment of VIE	(72,901)	—	—
NON-CASH FINANCING TRANSACTIONS:			
Issuance of stock for compensation and reinvested dividends	5,089	9,685	10,453
Deconsolidation of VIE	(83,096)	—	—
Assets acquired through capital leases	4,842	2,744	3,130

New Accounting Guidance

We prepare our consolidated financial statements in accordance with GAAP for the United States of America. To address current issues in accounting, the Financial Accounting Standards Board (FASB) and the Securities and Exchange Commission (SEC) issued the following new accounting guidance that may affect our accounting and/or disclosure.

Compensation - Retirement Benefits

In March 2017, the FASB issued Accounting Standard Update (ASU) No. 2017-07, which requires employers to disaggregate the service cost component from other components of net periodic benefit costs and to disclose the amounts of net periodic benefit costs that are included in each income statement line item. The standard requires employers to report the service cost component in the same line item as other compensation costs and to report the other components of net periodic benefit costs (which include interest costs, expected return on plan assets, amortization of prior service cost or credits and actuarial gains and losses) separately and outside a subtotal of operating income. Of the components of net periodic benefit cost, only the service cost component will be eligible for capitalization as property, plant and equipment, which is applied prospectively. The other components of net periodic benefit costs that are no longer eligible for capitalization as property, plant and equipment will be recorded as a regulatory asset. The guidance changing the presentation in the statements of income is applied on a retrospective basis. We adopted the guidance as of January 1, 2018, without a material impact on our consolidated financial statements.

Statement of Cash Flows

In August 2016, the FASB issued ASU No. 2016-15, which clarifies how certain cash receipts and cash payments are presented and classified in the statement of cash flows. Among other clarifications, the guidance requires that cash proceeds received from the settlement of COLI policies be classified as cash inflows from investing activities and that cash payments for premiums on COLI policies may be classified as cash outflows for investing activities, operating activities or a combination of both. Retrospective application is required. We adopted the guidance effective January 1, 2018, which will result in a reclassification of cash proceeds from the settlement of COLI policies from cash inflows from operating activities to cash inflows from investing activities. In addition, cash payments for premiums on COLI policies will be reclassified from cash outflows used in operating activities to cash outflows used in investing activities.

In November 2016, the FASB issued ASU No. 2016-18, which requires that the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents be explained in the statement of cash flows. The guidance requires a retrospective transition method. This guidance is effective for fiscal years beginning after December 15, 2017. We adopted the guidance effective January 1, 2018, without a material impact on our consolidated statement of cash flows.

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Stock-based Compensation

In March 2016, the FASB issued ASU No. 2016-09 as part of its simplification initiative. The areas for simplification involve several aspects of the accounting for stock-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. The guidance is effective for fiscal years beginning after December 15, 2016, with early adoption permitted. We adopted the guidance effective January 1, 2016.

Prior to the adoption of ASU 2016-09, if the tax deduction for a stock-based payment award exceeded the compensation cost recorded for financial reporting, the additional tax benefit was recognized in additional paid-in capital and referred to as an excess tax benefit. Tax deficiencies were recognized either as an offset to the accumulated excess tax benefits, if any, or as reduction of income. The issuance of this ASU reflects the FASB's decision that all prospective excess tax benefits and tax deficiencies should be recognized as income tax benefits or expense, respectively. Prior to the adoption of the ASU, additional paid-in-capital was not recognized to the extent that an excess tax benefit had not be realized (e.g., due to a carryforward of a net operating loss). Under the ASU, all excess tax benefits previously unrecognized because the related tax deduction had not reduced taxes payable are recognized on a modified retrospective basis as a cumulative-effect adjustment to retained earnings as of the date of adoption. Upon adoption, we recorded a $3.3 million cumulative effect adjustment to retained earnings for excess tax benefits that had not previously been recognized as well as a $3.3 million increase in deferred tax assets.

Further, the issuance of this ASU reflects the FASB's decision that cash flows related to excess tax benefits should be classified as cash flows from operating activities on the consolidated statements of cash flows. Upon adoption, we have retrospectively presented cash flows from operating activities on the accompanying consolidated statements of cash flows for the year ended December 31, 2015, as $1.3 million higher than as previously reported. We have retrospectively presented cash flows used in financing activities as $1.3 million higher for the year ended December 31, 2015, than as previously reported.

Leases

In February 2016, the FASB issued ASU No. 2016-02, which requires a lessee to recognize right-of-use assets and lease liabilities, initially measured at present value of the lease payments, on its balance sheet for leases with terms longer than 12 months. Leases are to be classified as either financing or operating leases, with that classification affecting the pattern of expense recognition in the income statement. Accounting for leases by lessors is largely unchanged. The criteria used to determine lease classification will remain substantially the same, but will be more subjective under the new guidance. The guidance is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. The guidance requires a modified retrospective approach for all leases existing at the earliest period presented, or entered into by the date of initial adoption, with certain practical expedients permitted. In 2016, we started evaluating our current leases to assess the initial impact on our consolidated financial results. We continue to evaluate the guidance and believe application of the guidance will result in an increase to our assets and liabilities on our consolidated balance sheet, with minimal impact to our consolidated statement of income. We also continue to monitor unresolved industry issues, including renewables and power purchase agreements and pole attachments, and will analyze the related impact. The standard permits an entity to elect a practical expedient for existing or expired contracts to forgo reassessing leases to determine whether each is in scope of the new standard and to forgo reassessing lease classification. We expect to elect this practical expedient upon implementation.

Financial Instruments - Credit Losses

In June 2016, the FASB issued ASU No. 2016-13, which requires financial assets measured at amortized cost be presented at the net amount expected to be collected. The allowance for credit losses is a valuation account that is deducted from the amortized cost basis. The measurement of expected losses is based upon historical experience, current conditions, and reasonable and supportable forecasts that affect the collectability of the reported amount. This guidance is effective for fiscal years beginning after December 15, 2019, with early adoption permitted. We are evaluating the guidance and have not yet determined the impact on our consolidated financial statements.

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Revenue Recognition

In May 2014, the FASB issued ASU No. 2014-09, which addresses revenue from contracts with customers. Subsequent ASUs have been released providing modifications and clarifications to ASU No. 2014-09. The objective of the new guidance is to establish principles to report useful information to users of financial statements about the nature, amount, timing and uncertainty of revenue from contracts with customers. Under the new standard, an entity must identify the performance obligations in a contract, determine the transaction price and allocate the price to specific performance obligations to recognize the revenue when the obligation is completed. This guidance is effective for fiscal years beginning after December 15, 2017; accordingly, we adopted the new standard on January 1, 2018. The standard permits the use of either the retrospective application or modified retrospective method. We elected to use the modified retrospective method, which requires a cumulative-effect adjustment to be recorded on the balance sheet as of the beginning of 2018, if applicable, as if the standard had always been in effect. Adoption of the standard will not have a material impact to our consolidated financial statements and, as a result, we recorded no cumulative effect of initially applying the standard.

Tax Cuts and Jobs Act

The SEC issued Staff Accounting Bulletin 118, which addresses the income tax accounting implications of the TCJA. The income tax effects of the TCJA in which the accounting is complete must be reflected in the financial statements. Additionally, provisional amounts in which reasonable estimates of the income tax effects of the TCJA can be determined should be included in the financial statements. Any specific income tax effect of the TCJA for which a reasonable estimate cannot be determined, would not be reported. Specific income tax effects of the TCJA that cannot be determined would continue to follow the provisions from the tax laws that were in effect immediately prior to the TCJA being enacted. We believe the accounting associated with the passage of the TCJA is complete and we have therefore not recorded any provisional amounts in our consolidated financial statements.

3. PENDING MERGER

On May 29, 2016, we entered into an agreement and plan of merger with Great Plains Energy Incorporated (Great Plains Energy) that provided for the acquisition of us by Great Plains Energy. On April 19, 2017, the Kansas Corporation Commission (KCC) rejected the prior transaction.

On July 9, 2017, we entered into an amended and restated agreement and plan of merger with Great Plains Energy that provides for a merger of equals between the two companies. Upon closing, each issued and outstanding share of our common stock will be converted into one share of common stock of a new holding company with a final name still to be determined. Upon closing, each issued and outstanding share of Great Plains Energy common stock will be converted into 0.5981 shares of common stock of the new holding company. Following completion of the merger, our shareholders are expected to own approximately 52.5% of the new holding company and Great Plains Energy’s shareholders are expected to own approximately 47.5% of the new holding company.

The merger agreement includes certain restrictions and limitations on our ability to declare dividend payments. The merger agreement, without prior approval of Great Plains Energy, limits our quarterly dividends declared to $0.40 per share.

The closing of the merger is subject to conditions including receipt of all required regulatory approvals from, among others, the Federal Energy Regulatory Commission (FERC), Nuclear Regulatory Commission (NRC), KCC, and Public Service Commission of the State of Missouri (MPSC) (provided that such approvals do not result in a material adverse effect on Great Plains Energy or us, after giving effect to the merger, measured on the size and scale of Westar Energy and its subsidiaries, taken as a whole); effectiveness of the registration statement for the shares of the new holding company’s common stock to be issued to our shareholders and Great Plains Energy’s shareholders upon consummation of the merger and approval of the listing of such shares on the New York Stock Exchange; the receipt of tax opinions by us and Great Plains Energy that the merger will be treated as a non-taxable event for U.S. federal

income tax purposes; there being no shares of Great Plains Energy preference stock outstanding; and Great Plains Energy having not less than $1.25 billion in cash or cash equivalents on its balance sheet. The closing of the merger is also subject to other standard conditions, such as accuracy of representations and warranties, compliance with covenants and the absence of a material adverse effect on either company.
The merger agreement, which contains customary representations, warranties, and covenants, may be terminated by either party if the merger has not occurred by July 10, 2018. The termination date may be extended six months in order to obtain regulatory approvals.

On August 25, 2017, we and Great Plains Energy filed a joint application with the KCC requesting approval of the merger. The KCC subsequently approved a procedural schedule that provides for a KCC order on the proposed merger by

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June 5, 2018, although under Kansas law the KCC has until June 21, 2018 to issue the order. On August 31, 2017, we and Great Plains Energy applied for approval of the merger from the MPSC. On January 12, 2018, we, Great Plains Energy, the MPSC staff and certain intervenors entered into a stipulation and agreement to settle certain issues related to the joint application. The stipulation and agreement is subject to review and approval by the MPSC. On September 1, 2017, we and Great Plains Energy filed a joint application for approval of the merger with FERC, and we expect to receive a final order by the end of February 2018, unless FERC takes action that results in an extension of this date. On September 5, 2017, Wolf Creek filed a request with the NRC to approve an indirect transfer of control of Wolf Creek's operating license. We and Great Plains Energy each gained shareholder approval of the proposed merger on November 21, 2017. Also, we and Great Plains Energy received early termination of the statutory waiting period under the Hart-Scott-Rodino Antitrust Improvements Act on December 12, 2017.

The amended and restated merger agreement provides that Great Plains Energy may be required to pay us a termination fee of $190.0 million if the agreement is terminated due to (i) failure to receive regulatory approval prior to July 10, 2018, subject to an extension of up to six months, (ii) a non-appealable regulatory order enjoining the merger or (iii) Great Plains Energy's failure to close after all conditions precedent to closing have been satisfied. In addition, we may be required to pay Great Plains Energy a termination fee of $190.0 million if the agreement is terminated by us under certain circumstances, such as entering into a definitive acquisition agreement with respect to a superior proposal. Similarly, Great Plains Energy may be required to pay us a termination fee of $190.0 million if the agreement is terminated by Great Plains Energy under certain circumstances, such as entering into a definitive acquisition agreement with respect to a superior proposal.

In connection with the merger, we have incurred, and expect to incur additional, merger-related expenses. These expenses are included in our selling, general, and administrative expenses. For the years ended December 31, 2017 and 2016, we incurred approximately $10.8 million and $10.2 million of merger-related expenses. In the event that the merger is consummated, we expect total merger-related expenses will be approximately $45.0 million.

See also Note 16, "Legal Proceedings," for more information on litigation related to the merger.

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4. 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,	
	2017	2016
	(In Thousands)	
Regulatory Assets:		
Deferred employee benefit costs	$393,890	$381,129
Debt reacquisition costs	109,169	115,502
Depreciation	60,598	63,171
Asset retirement obligations	42,676	35,487
Analog meter unrecovered investment	31,545	8,500
Removal costs	30,847	—
Treasury yield hedges	24,814	25,927
Retail energy cost adjustment	20,741	32,451
Ad valorem tax	17,389	17,637
Disallowed plant costs	15,249	15,453
La Cygne environmental costs	13,295	14,370
Energy efficiency program costs	8,096	7,097
Wolf Creek outage	6,967	20,316
Amounts due from customers for future income taxes, net	—	124,020
Other regulatory assets	9,623	18,802
Total regulatory assets	$784,899	$879,862
Regulatory Liabilities:		
Income taxes, net	$845,240	$—
Deferred regulatory gain from sale leaseback	64,569	70,065
Nuclear decommissioning	55,531	34,094
Pension and other post-retirement benefits costs	48,356	37,172
Jurisdictional allowance for funds used during construction	31,707	33,119
La Cygne leasehold dismantling costs	29,552	27,742
Kansas tax credits	16,844	13,142
Purchase power agreement	8,823	9,265
Removal costs	—	5,663
Other regulatory liabilities	4,954	9,191
Total regulatory liabilities	$1,105,576	$239,453

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 $374.2 million for pension and post-retirement benefit obligations and $19.7 million for actual pension expense in excess of the amount of such expense recognized in setting our prices. The increase in regulatory assets for pension and post-retirement benefit obligations from 2016 to 2017 is attributable primarily to a decrease in the discount rates used to calculate our and Wolf Creek's pension benefit obligations. During 2018, we will amortize to expense approximately $33.5 million of the benefit obligations and approximately $6.8 million of the excess pension expense. We are amortizing the excess pension expense over a five-year period. We do not earn a return on this asset.

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- 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.

- 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.

- Asset retirement obligations: Represents amounts associated with our AROs as discussed in Note 15, "Asset Retirement Obligations." We recover these amounts over the life of the related plant. We do not earn a return on this asset.

- Analog meter unrecovered investment: Represents the deferral of unrecovered investment of analog meters retired between October 2015 and the next general rate review. Once these amounts are included in base rates established in our next general rate review, we will amortize these amounts over a five-year period and will not earn a return on this asset.

- Removal costs: Represents amounts spent, but not yet collected, to dispose of plant assets. This asset will decrease as removal costs are collected in our prices. We do not earn a return on this asset.

- Treasury yield hedges: Represents the effective portion of treasury yield hedge transactions. This amount will be amortized to interest expense over the term of the related debt. We do not earn a return on this asset.

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

- 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.

- 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.

- La Cygne environmental costs: Represents the deferral of depreciation and amortization expense and associated carrying charges related to the La Cygne Generating Station (La Cygne) environmental project from the in-service date until late October 2015, the effective date of our state general rate review. This amount will be amortized over the life of the related asset. We earn a return on this asset.

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

- Wolf Creek outage: 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.

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- 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 received 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. 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. We do not earn a return on this net 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.

- Income taxes, net: We have recorded a regulatory liability for our obligation to reduce the prices charged to customers for deferred income taxes recovered from customers in earlier periods when corporate income tax rates were higher than current income tax rates under TCJA. Most of this regulatory liability is related to depreciation and will be returned to customers over the life of the applicable property. Also, in accordance with various orders, we have reduced our prices to reflect the income tax benefits associated with certain accelerated income tax deductions, thereby passing on these benefits to customers at the time we received 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 for these amounts, which is offset against the regulatory liability.

- Deferred regulatory gain from sale leaseback: Represents the gain KGE recorded on the 1987 sale and leaseback of its 50% interest in 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 the accumulated accretion and depreciation expense associated with our ARO. See Notes 5, 6 and 15, “Financial Instruments and Trading Securities,” “Financial Investments” and “Asset Retirement Obligations,” respectively, for information regarding our nuclear decommissioning trust (NDT) and our ARO.

- Pension and other post-retirement benefits costs: Includes $12.6 million for pension and post-retirement benefit obligations and $35.7 million for pension and post-retirement expense recognized in setting our prices in excess of actual pension and post-retirement expense. During 2018, we will amortize to expense approximately $0.3 million of the benefit obligations and approximately $3.4 million of the excess pension and post-retirement expense recognized in setting our prices. We will amortize the excess pension and post-retirement expense over a five-year period.

- 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 prices and prior to the time the related assets are placed in service. The AFUDC is amortized to depreciation expense over the useful life of the asset that is placed in service.

- La Cygne leasehold 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.

- 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.

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- Purchase power agreement: This item represents the amount included in retail electric rates from customers in excess of the costs incurred by us under the purchase power agreement with Westar Generating. We amortize the amount over a three-year period.

- Removal costs: Represents amounts collected, but not yet spent, to dispose of plant assets. This liability will be discharged as removal costs are incurred.

- 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 February 2018, we filed an application with the KCC to update our prices to include, among other things, costs associated with the completion of Western Plains Wind Farm; expiration of wholesale contracts currently reflected in retail prices as offsets to retail cost of service; expiring production tax credits from initial wind investments; and an updated depreciation study. This application also includes savings due to the recently passed TCJA, savings achieved from refinancing debt, and savings from the proposed merger with Great Plains Energy. If approved we estimate the new prices will decrease our annual revenues by approximately $2.0 million in September 2018, followed by an increase in our annual revenues of $54.0 million in February 2019. We expect the KCC to issue an order on our request by September 2018.

In January 2018, the KCC issued an order to investigate the effect of the TCJA on regulated utilities. The KCC stated the passage of the TCJA has the potential to significantly reduce the cost of service for utilities, and it may impact the regulatory assets and liabilities of Kansas utilities. Therefore, beginning in January 2018, the KCC directed all regulated electric public utilities that are taxable at the corporate level, to accrue monthly, in a deferred revenue account, the portion of its revenue representing the difference between: (1) the cost of service as approved by the KCC in its most recent rate review; and (2) the cost of service that would have resulted had the provision for federal corporate income taxes been based upon the corporate tax rate approved in the TCJA. The KCC also gave notice to taxable utilities operating in Kansas that the portion of their regulated revenue stream that reflects higher corporate tax rates should be considered interim and subject to refund, with interest. When the KCC’s evaluation of the impact of the TCJA is complete, if it is determined that a retail price decrease is proper and would have been proper as of the effective date of the TCJA, these amounts will be returned to customers.

In June 2017, the KCC issued an order in our abbreviated rate review allowing us to adjust our prices to include capital costs related to La Cygne environmental upgrades, investment to extend the life of Wolf Creek, costs related to programs to improve grid resiliency and costs associated with investments in other environmental projects during 2015. The new prices were effective June 2017 and are expected to increase our annual retail revenues by approximately $16.4 million.

In September 2015, the KCC issued an order in our state general rate review allowing us to adjust our prices to include, among other things, additional investment in La Cygne environmental upgrades and investment to extend the life of Wolf Creek. The new prices were effective late October 2015 and are expected to increase our annual retail revenues by approximately $78.3 million.

Environmental Costs

In October 2015, in connection with the state general rate review, we agreed to no longer 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. The existing balance of costs associated with these investments were rolled into our base prices. In the future, we will need to seek approval from the KCC for individual projects. In the most recent three years, the KCC issued orders related to such filings allowing us to increase our annual retail revenues by approximately $10.8 million effective in June 2015.

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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 (TFR) 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:

- $12.7 million effective in April 2017;
- $7.0 million effective in April 2016; and
- $7.2 million effective in April 2015.

In June 2016, the KCC approved an order allowing us to adjust our retail prices to include updated transmission costs as reflected in the TFR, along with the reduced return on equity (ROE) as described below. The updated prices were retroactively effective April 2016. We began refunding our previously-recorded refund obligation in 2016 and as of December 31, 2016, we had a remaining refund obligation of $1.3 million, which is included in current regulatory liabilities on our balance sheet. As of December 31, 2017, we have fully refunded this obligation.

Property Tax Surcharge

We make annual filings with the KCC to adjust our prices to include the cost incurred for property taxes. In October 2015, in connection with the state general rate review, the existing balance of costs incurred for property taxes were rolled into our base prices. In the most recent four years, the KCC issued orders related to such filings allowing us to adjust our annual retail revenues by approximately:

- $0.2 million decrease effective in January 2018;
- $26.8 million decrease effective in January 2017;
- $5.0 million increase effective in January 2016; and
- $4.9 million increase effective in January 2015.

FERC Proceedings

In October of each year, we post an updated TFR 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 four years, we posted our TFR, which was expected to adjust our annual transmission revenues by approximately:

- $25.5 million increase effective in January 2018;
- $29.6 million increase effective in January 2017;
- $24.0 million increase effective in January 2016; and
- $4.6 million decrease effective in January 2015.

In March 2016, the FERC approved a settlement reducing our base ROE used in determining our TFR. The settlement resulted in an ROE of 10.3%, which consists of a 9.8% base ROE plus a 0.5% incentive ROE for participation in a regional transmission organization (RTO). The updated prices were retroactively effective January 2016. This adjustment also reflected estimated recovery of increased transmission capital expenditures and operating costs. We began refunding our previously recorded refund obligation in 2016 and as of December 31, 2016, we had a remaining refund obligation of $1.2 million, which is included in current regulatory liabilities on our balance sheet. As of December 31, 2017, we have fully refunded this obligation.

5. FINANCIAL INSTRUMENTS AND TRADING SECURITIES

Values of Financial 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. In addition, we measure certain investments that do not have a readily determinable fair value at net asset value (NAV), which are not included in the fair value hierarchy. Further explanation of these levels and NAV is summarized below.

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- 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 liquid investments in funds that have a readily determinable fair value calculated using daily NAVs, other financial instruments that are comparable to actively traded securities or contracts, such as treasury securities with pricing interpolated from recent trades of similar securities, or other financial instruments 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.

- Net Asset Value - Investments that do not have a readily determinable fair value are measured at NAV. These investments do not consider the observability of inputs, therefore, they are not included within the fair value hierarchy. We include in this category investments in private equity, real estate and alternative investment funds that do not have a readily determinable fair value. The underlying alternative investments include collateralized debt obligations, mezzanine debt and a variety of other investments.

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.

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, 2017		As of December 31, 2016	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In Thousands)			
Fixed-rate debt	$3,605,000	$3,888,620	$3,430,000	$3,597,441
Fixed-rate debt of VIEs	109,967	110,756	137,962	139,733

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Recurring Fair Value Measurements

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

As of December 31, 2017	Level 1	Level 2	Level 3	NAV	Total
	(In Thousands)				
Nuclear Decommissioning Trust:					
Domestic equity funds	$—	$68,658	$ —	$5,142	$73,800
International equity funds	—	47,908	—	—	47,908
Core bond fund	—	33,250	—	—	33,250
High-yield bond fund	—	18,089	—	—	18,089
Emerging markets bond fund	—	17,345	—	—	17,345
Combination debt/equity/other fund	—	14,125	—	—	14,125
Alternative investments fund	—	—	—	21,669	21,669
Real estate securities fund	—	—	—	10,806	10,806
Cash equivalents	110	—	—	—	110
Total Nuclear Decommissioning Trust	110	199,375	—	37,617	237,102
Trading Securities:					
Core bond fund	—	27,324	—	—	27,324
Combination debt/equity/other fund	—	6,831	—	—	6,831
Cash equivalents	156	—	—	—	156
Total Trading Securities	156	34,155	—	—	34,311
Total Assets Measured at Fair Value	$266	$233,530	$ —	$37,617	$271,413

As of December 31, 2016	Level 1	Level 2	Level 3	NAV	Total
	(In Thousands)				
Nuclear Decommissioning Trust:					
Domestic equity funds	$—	$56,312	$ —	$5,056	$61,368
International equity funds	—	35,944	—	—	35,944
Core bond fund	—	27,423	—	—	27,423
High-yield bond fund	—	18,188	—	—	18,188
Emerging markets bond fund	—	14,738	—	—	14,738
Combination debt/equity/other fund	—	13,484	—	—	13,484
Alternative investments fund	—	—	—	18,958	18,958
Real estate securities fund	—	—	—	9,946	9,946
Cash equivalents	73	—	—	—	73
Total Nuclear Decommissioning Trust	73	166,089	—	33,960	200,122
Trading Securities:					
Domestic equity funds	—	18,364	—	—	18,364
International equity fund	—	4,467	—	—	4,467
Core bond fund	—	11,504	—	—	11,504
Cash equivalents	156	—	—	—	156
Total Trading Securities	156	34,335	—	—	34,491
Total Assets Measured at Fair Value	$229	$200,424	$ —	$33,960	$234,613

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Some of our investments in the NDT are measured at NAV and do not have readily determinable fair values. These investments 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, 2017		As of December 31, 2016		As of December 31, 2017	
	Fair Value	Unfunded Commitments	Fair Value	Unfunded Commitments	Redemption Frequency	Length of Settlement
	(In Thousands)					
Nuclear Decommissioning Trust:						
Domestic equity funds	$5,142	$ 2,808	$5,056	$ 3,529	(a)	(a)
Alternative investments fund (b)	21,669	—	18,958	—	Quarterly	65 days
Real estate securities fund (b)	10,806	—	9,946	—	Quarterly	65 days
Total	$37,617	$ 2,808	$33,960	$ 3,529		

(a) This investment is in four 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. Three funds have begun to make distributions. Our initial investment in the fourth fund occurred in the second quarter of 2016. This fund's term is 15 years, subject to the general partner's right to extend the term for up to three additional one-year periods.

(b) There is a holdback on final redemptions.

Derivative Instruments

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 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 10, "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.

6. 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 that we classify as trading securities in a trust used to fund certain retirement benefit obligations. These obligations totaled $27.4 million and $26.8 million as of December 31, 2017 and 2016, respectively. For additional information on our benefit obligations, see Note 12, “Employee Benefit Plans.”

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As of December 31, 2017 and 2016, we measured the fair value of trust assets at $34.3 million and $34.5 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, 2017, 2016 and 2015, we recorded unrealized gains of $4.0 million, $2.5 million and $0.4 million, respectively, on assets still held.

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, 2017 and 2016.

Using the specific identification method to determine cost, we realized no gain or loss on our available-for-sale securities in 2017. We realized a loss on our available-for-sale securities of $1.5 million and $0.9 million in 2016 and 2015, respectively. 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, respectively, 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, 2017 and 2016.

		Gross Unrealized			
Security Type	Cost	Gain	Loss	Fair Value	Allocation
	(Dollars In Thousands)				
As of December 31, 2017:					
Domestic equity funds	$67,348	$7,187	$(735)	$73,800	31 %
International equity funds	36,324	11,584	—	47,908	20 %
Core bond fund	33,381	—	(131)	33,250	14 %
High-yield bond fund	17,989	100	—	18,089	8 %
Emerging markets bond fund	17,449	—	(104)	17,345	7 %
Combination debt/equity/other fund	8,311	5,814	—	14,125	6 %
Alternative investments fund	15,000	6,669	—	21,669	9 %
Real estate securities fund	9,500	1,306	—	10,806	5 %
Cash equivalents	110	—	—	110	<1%
Total	$205,412	$32,660	$(970)	$237,102	100 %
As of December 31, 2016:					
Domestic equity funds	$53,192	$8,295	$(119)	$61,368	31 %
International equity funds	34,502	2,075	(633)	35,944	18 %
Core bond fund	27,952	—	(529)	27,423	14 %
High-yield bond fund	18,358	—	(170)	18,188	9 %
Emerging markets bond fund	16,397	—	(1,659)	14,738	7 %
Combination debt/equity/other fund	9,171	4,313	—	13,484	7 %
Alternative investments fund	15,000	3,958	—	18,958	9 %
Real estate securities fund	9,500	446	—	9,946	5 %
Cash equivalents	73	—	—	73	<1%
Total	$184,145	$19,087	$(3,110)	$200,122	100 %

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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, 2017 and 2016.

	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, 2017:						
Domestic equity funds	$1,784	$ (362)	$1,871	$ (373)	$3,655	$ (735)
Core bond fund	—	—	33,250	(131)	33,250	(131)
Emerging markets bond fund	17,345	(104)	—	—	17,345	(104)
Total	$19,129	$ (466)	$35,121	$ (504)	$54,250	$ (970)
As of December 31, 2016:						
Domestic equity funds	$1,788	$ (119)	$—	$ —	$1,788	$ (119)
International equity funds	—	—	7,489	(633)	7,489	(633)
Core bond fund	27,423	(529)	—	—	27,423	(529)
High-yield bond fund	—	—	18,188	(170)	18,188	(170)
Emerging markets bond fund	—	—	14,738	(1,659)	14,738	(1,659)
Total	$29,211	$ (648)	$40,415	$ (2,462)	$69,626	$ (3,110)

7. PROPERTY, PLANT AND EQUIPMENT

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

	As of December 31,	
	2017	2016
	(In Thousands)	
Electric plant in service	$12,954,247	$11,986,046
Electric plant acquisition adjustment	739,037	802,318
Accumulated depreciation	(4,651,748)	(4,404,977)
	9,041,536	8,383,387
Construction work in progress	434,927	773,095
Nuclear fuel, net	71,426	61,952
Plant to be retired, net (a)	5,866	29,925
Net property, plant and equipment	$9,553,755	$9,248,359

(a) Represents the planned retirement of analog meters prior to the end of their remaining useful lives due to modernization of meter technology. See Note 4, “Rate Matters and Regulation,” for additional information.

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

	As of December 31,	
	2017	2016
	(In Thousands)	
Electric plant of VIEs	$392,100	$497,999
Accumulated depreciation of VIEs	(215,821)	(240,095)

Net property, plant and equipment of VIEs	$176,279	$257,904

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We recorded depreciation expense on property, plant and equipment of $350.0 million in 2017, $316.7 million in 2016 and $287.9 million in 2015. Approximately $8.3 million, $9.5 million and $9.6 million of depreciation expense in 2017, 2016 and 2015, respectively, was attributable to property, plant and equipment of VIEs.

8. JOINT OWNERSHIP OF UTILITY PLANTS

Under joint ownership agreements with other utilities, we have undivided ownership interests in four electric generating stations. Energy generated and operating expenses are divided on the same basis as ownership with each owner reflecting its respective costs in its statements of income and each owner responsible for its own financing. Information relative to our ownership interests in these facilities as of December 31, 2017, 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	$639,265	$ 171,749	$ 29,511	368	50
JEC unit 1 (a)	July 1978	843,945	207,358	1,703	670	92
JEC unit 2 (a)	May 1980	577,590	206,041	2,190	672	92
JEC unit 3 (a)	May 1983	740,467	337,941	17,995	659	92
Wolf Creek (b)	Sept. 1985	1,867,487	819,772	90,184	552	47
State Line (c)	June 2001	112,679	66,858	454	196	40
Total		$4,781,433	$ 1,809,719	$ 142,037	3,117	

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(a) Jointly owned with Kansas City Power & Light Company (KCPL). Our 8% leasehold interest in Jeffrey Energy Center (JEC) is reflected in the net megawatts (MW) and ownership percentage provided above.
(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 consolidate a VIE that holds our 50% leasehold interest in La Cygne unit 2, which represents 331 MW of net capacity. The VIE's investment in the 50% interest was $392.1 million and accumulated depreciation was $215.8 million as of December 31, 2017. We include these amounts in property, plant and equipment of VIEs, net on our consolidated balance sheets. See Note 18, "Variable Interest Entities," for additional information about VIEs.

9. SHORT-TERM DEBT

In December 2017, Westar Energy extended the term of the $270.0 million revolving credit facility to terminate in February 2019. So 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, 2017 and 2016, Westar Energy had no borrowed amounts or letters of credit outstanding under this revolving credit facility.

In September 2015, Westar Energy extended the term of its $730.0 million revolving credit facility to terminate in September 2019, $20.7 million of which expired 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, 2017, no amounts had been borrowed and $11.8 million of letters of credit had been issued under this revolving credit facility. As of December 31, 2016, no amounts had been borrowed and $12.3 million of letters of credit had been issued under this revolving credit facility.

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Westar Energy maintains 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 and cannot exceed the capacity under 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 redeem debt on an interim basis, for working capital and/or for other general corporate purposes. Westar Energy had $275.7 million and $366.7 million of commercial paper issued and outstanding as of December 31, 2017 and 2016, 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, 2017 and 2016, was 1.83% and 0.96%, respectively. Additional information regarding our short-term debt is as follows.

	Year Ended December 31,	
	2017	2016
	(Dollars in Thousands)	
Weighted average short-term debt outstanding	$306,245	$284,700
Weighted daily average interest rates, excluding fees	1.29 %	0.78 %

Our interest expense on short-term debt was $5.2 million in 2017, $3.6 million in 2016 and $3.0 million in 2015.

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10. LONG-TERM DEBT

Outstanding Debt

The following table summarizes our long-term debt outstanding.

	As of December 31,	
	2017	2016
	(In Thousands)	
Westar Energy		
First mortgage bond series:		
5.15% due 2017	$—	$125,000
5.10% due 2020	250,000	250,000
3.25% due 2025	250,000	250,000
2.55% due 2026	350,000	350,000
3.10% due 2027	300,000	—
4.125% due 2042	550,000	550,000
4.10% due 2043	430,000	430,000
4.625% due 2043	250,000	250,000
4.25% due 2045	300,000	300,000
	2,680,000	2,505,000
Pollution control bond series:		
Variable due 2032, 1.92% as of December 31, 2017; 1.14% as of December 31, 2016	45,000	45,000
Variable due 2032, 1.94% as of December 31, 2017; 1.32% as of December 31, 2016	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
4.30% due 2044	250,000	250,000
	875,000	875,000
Pollution control bond series:		
Variable due 2027, 2.00% as of December 31, 2017; 1.46% as of December 31, 2016	21,940	21,940
2.50% due 2031	50,000	50,000
Variable due 2032, 2.00% as of December 31, 2017; 1.46% as of December 31, 2016	14,500	14,500
Variable due 2032, 2.00% as of December 31, 2017; 1.46% as of December 31, 2016	10,000	10,000
	96,440	96,440
Total long-term debt	3,726,940	3,551,940
Unamortized debt discount (a)	(10,925)	(10,358)
Unamortized debt issuance expense (a)	(28,460)	(27,912)
Long-term debt due within one year	—	(125,000)
Long-term debt, net	$3,687,555	$3,388,670
Variable Interest Entities		
5.92% due 2019 (b)	$—	$1,157
2.398% due 2021 (b)	109,967	136,805

Total long-term debt of variable interest entities	109,967	137,962
Unamortized debt premium (a)	—	89
Long-term debt of variable interest entities due within one year	(28,534)	(26,842)
Long-term debt of variable interest entities, net	$81,433	$111,209

(a) We amortize debt discounts and issuance expense 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 (FMBs) 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.

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The amount of Westar Energy FMBs 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 FMBs 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. FMBs 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, 2017, approximately $929.7 million principal amount of additional FMBs could be issued under the most restrictive provisions in Westar Energy's mortgage. As of December 31, 2017, approximately $1.5 billion principal amount of additional KGE FMBs could be issued under the most restrictive provisions in KGE's mortgage.

As of December 31, 2017, we had $121.9 million of variable rate, tax-exempt bonds outstanding. While the interest rates for these bonds have been low, we continue to monitor the credit markets and evaluate our options with respect to these bonds.

In March 2017, Westar Energy issued $300.0 million in principal amount of FMBs bearing a stated interest at 3.10% maturing April 2027.

In January 2017, Westar Energy retired $125.0 million in principal amount of FMBs bearing a stated interest at 5.15% maturing January 2017.

In June 2016, Westar Energy issued $350.0 million in principal amount of FMBs bearing a stated interest at 2.55% and maturing July 2026. The bonds were issued as "Green Bonds," and all proceeds from the bonds were used in renewable energy projects, primarily the construction of the Western Plains Wind Farm.

Also in June 2016, KGE redeemed and reissued $50.0 million in principal amount pollution control bonds maturing June 2031. The stated rate of the bonds was reduced from 4.85% to 2.50%.

In February 2016, KGE, as lessee to the La Cygne sale-leaseback, effected a redemption and reissuance of $162.1 million in outstanding bonds held by the trustee of the lease maturing March 2021. The stated interest rate of the bonds was reduced from 5.647% to 2.398%. See Note 18, "Variable Interest Entities," for additional information regarding our La Cygne sale-leaseback.

With the exception of Green 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, 2017, are as follows.

Year	Long-term debt	Long-term debt of VIEs
	(In Thousands)	
2018	$—	$ 28,534
2019	300,000	30,337
2020	250,000	32,254
2021	—	18,842
2022	—	—
Thereafter	3,176,940	—
Total maturities	$ 3,726,940	$ 109,967

Interest expense on long-term debt, net of debt AFUDC, was $151.7 million in 2017, $141.4 million in 2016 and $152.7 million in 2015. Interest expense on long-term debt of VIEs was $2.8 million in 2017, $4.2 million in 2016 and $9.8 million in 2015.

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11. TAXES

Income tax expense is comprised of the following components.

	Year Ended December 31,		
	2017	2016	2015
	(In Thousands)		
Income Tax Expense (Benefit):			
Current income taxes:			
Federal	$126	$(1,007)	$327
State	359	318	341
Deferred income taxes:			
Federal	122,757	155,230	124,891
State	30,675	32,892	29,484
Investment tax credit amortization	(2,762)	(2,893)	(3,043)
Income tax expense	$151,155	$184,540	$152,000

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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,	
	2017	2016
	(In Thousands)	
Deferred tax assets:		
Tax credit carryforward (a)	$323,518	$265,750
Income taxes refundable to customers, net	230,348	—
Deferred employee benefit costs	95,913	137,337
Net operating loss carryforward (b)	70,041	86,693
Deferred state income taxes	63,838	73,294
Alternative minimum tax carryforward (c)	52,187	29,412
Deferred compensation	21,600	31,981
Deferred regulatory gain on sale-leaseback	17,148	30,868
Accrued liabilities	13,193	21,757
La Cygne dismantling costs	7,840	10,972
Disallowed costs	5,800	9,600
Other	45,484	47,200
Total deferred tax assets	$946,910	$744,864
Deferred tax liabilities:		
Plant-related	$1,483,276	$1,925,270
Deferred employee benefit costs	95,913	137,337
Acquisition premium	76,574	147,868
Deferred state income taxes	46,940	61,110
Debt reacquisition costs	26,539	41,753
Amounts due from customers for future income taxes, net	—	124,020
Other	33,411	60,282
Total deferred tax liabilities	$1,762,653	$2,497,640
Net deferred income tax liabilities	$815,743	$1,752,776

(a) Based on filed tax returns and amounts expected to be reported in current year tax returns (December 31, 2017), we had available federal general business tax credits of $100.0 million and state investment tax credits of $223.5 million. The federal general business tax credits were primarily generated from production tax credits. These tax credits expire beginning in 2020 and ending in 2037. The state investment tax credits expire beginning in 2024 and ending in 2033.

(b) As of December 31, 2017, we had a federal net operating loss carryforward of $181.1 million, which is available to offset federal taxable income and a state net operating loss of $470.4 million, which is available to offset state taxable income. The federal net operating losses will expire beginning in 2032 and ending in 2036 and the state net operating losses will expire beginning in 2020 and ending in 2027.

(c) As of December 31, 2017, we had available an alternative minimum tax credit carryforward of $52.2 million. This credit is refundable by tax year 2021, if not fully utilized.

The TCJA, which was signed into law in December 2017, significantly reforms the IRC and is generally effective January 1, 2018. The TCJA contains significant changes to federal corporate income taxation, including, in general and among other things, a federal corporate income tax rate decrease from 35% to 21% effective for tax years beginning after December 31, 2017, limiting the deduction for net operating losses, eliminating net operating loss carrybacks for losses after 2017 and eliminating our use of bonus depreciation on new capital investments. As a result, we decreased deferred income tax liabilities by approximately $1.0 billion and made corresponding adjustments to regulatory assets and regulatory liabilities. In addition, in 2017 we decreased non-regulated net deferred income tax assets by approximately $12.2 million and correspondingly recorded an increase in income tax expense, which increased our effective tax rate by 2.5%.

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We have recorded a regulatory liability for our obligation to reduce the prices charged to customers for deferred income taxes recovered from customers in earlier periods when corporate income tax rates were higher than current income tax rates under the TCJA. Most of this regulatory liability is related to depreciation and will be returned to the customer through lower rates over the life of the applicable property. Also, in accordance with various orders, we have reduced our prices to reflect the income tax benefits associated with certain accelerated income tax deductions, thereby passing on these benefits to customers at the time we received 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 for these amounts, which is offset against the regulatory liability. 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.

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,		
	2017	2016	2015
Statutory federal income tax rate	35.0 %	35.0 %	35.0 %
Effect of:			
Production tax credits	(6.9)	(1.8)	(2.1)
State income taxes	4.1	4.0	4.3
COLI policies	(3.1)	(4.2)	(4.4)
Federal income tax rate reduction (TCJA)	2.5	—	—
Flow through depreciation for plant-related differences	2.3	3.1	2.6
Non-controlling interest	(0.9)	(0.9)	(0.8)
Share based payments	(0.9)	(0.5)	(0.1)
Amortization of federal investment tax credits	(0.6)	(0.5)	(0.7)
AFUDC equity	(0.2)	(0.8)	(0.2)
Other	(0.3)	0.4	(0.1)
Effective income tax rate	31.0 %	33.8 %	33.5 %

We file income tax returns in the U.S. federal jurisdiction as well as various state 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 or state and local income tax examinations by tax authorities remains open for tax year 2014 and forward.

The unrecognized income tax benefits decreased from $2.8 million at December 31, 2016, to $1.7 million at December 31, 2017. The net decrease for unrecognized income tax benefits was primarily attributable to tax positions expected to be taken with respect to potential deductions related to an environmental settlement agreement. We do not expect significant changes in the 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:

	2017	2016	2015
	(In Thousands)		
Unrecognized income tax benefits as of January 1	$2,766	$2,901	$3,188
Additions based on tax positions related to the current year	165	434	410
Additions for tax positions of prior years	20	—	—
Reductions for tax positions of prior years	(870)	(1)	(86)
Lapse of statute of limitations	(361)	(568)	(611)
Unrecognized income tax benefits as of December 31	$1,720	$2,766	$2,901

The amounts of unrecognized income tax benefits that, if recognized, would favorably impact our effective income tax rate, were $1.6 million, $2.7 million and $2.9 million (net of tax) as of December 31, 2017, 2016 and 2015, respectively.

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Interest related to income tax uncertainties is classified as interest expense and accrued interest liability. As of December 31, 2017 and 2016, we had $0.1 million and no amounts accrued for interest on our liability related to unrecognized income tax benefits, respectively. We accrued no penalties at either December 31, 2017 or 2016.

As of December 31, 2017 and 2016, we had recorded $0.4 million and $1.5 million, respectively, for probable assessments of taxes other than income taxes.

12. 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.

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 13, “Wolf Creek Employee Benefit Plans,” for information about Wolf Creek’s benefit plans.

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

	Pension Benefits		Post-retirement Benefits	
As of December 31,	2017	2016	2017	2016
	(In Thousands)			
Change in Benefit Obligation:				
Benefit obligation, beginning of year	$1,012,024	$965,193	$129,563	$126,284
Service cost	20,874	18,563	1,084	1,084
Interest cost	42,482	43,723	5,255	5,571
Plan participants' contributions	—	—	362	395
Benefits paid	(53,704)	(63,540)	(7,614)	(7,697)
Actuarial losses	83,553	51,482	2,899	3,926
Amendments	—	(3,397)	—	—
Benefit obligation, end of year (a)	$1,105,229	$1,012,024	$131,549	$129,563
Change in Plan Assets:				
Fair value of plan assets, beginning of year	$658,474	$653,945	$115,619	$115,416
Actual return on plan assets	88,030	45,181	15,498	7,274
Employer contributions	24,300	20,200	—	—
Plan participants' contributions	—	—	327	356
Benefits paid	(51,472)	(60,852)	(7,374)	(7,427)
Fair value of plan assets, end of year	$719,332	$658,474	$124,070	$115,619
Funded status, end of year	$(385,897)	$(353,550)	$(7,479)	$(13,944)
Amounts Recognized in the Balance Sheets Consist of:				
Current liability	$(2,223)	$(2,260)	$(255)	$(284)
Noncurrent liability	(383,674)	(351,290)	(7,224)	(13,660)
Net amount recognized	$(385,897)	$(353,550)	$(7,479)	$(13,944)
Amounts Recognized in Regulatory Assets (Liabilities) Consist of:				
Net actuarial loss (gain)	$299,068	$282,462	$(12,549)	$(7,603)
Prior service cost	3,231	3,913	2,219	2,674
Net amount recognized	$302,299	$286,375	$(10,330)	$(4,929)

(a) As of December 31, 2017 and 2016, pension benefits include non-qualified benefit obligations of $27.4 million and $26.8 million, respectively, which are funded by a trust containing assets of $34.3 million and $34.5 million, respectively, classified as trading securities. The assets in the aforementioned trust are not included in the table above. See Notes 5 and 6, "Financial Instruments and Trading Securities" and "Financial Investments," respectively, for additional information regarding these amounts.

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As of December 31,	Pension Benefits 2017	2016	Post-retirement Benefits 2017	2016
	(Dollars in Thousands)			
Pension Plans With a Projected Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$1,105,229	$1,012,024	$—	$—
Fair value of plan assets	719,332	658,474	—	—
Pension Plans With an Accumulated Benefit Obligation In Excess of Plan Assets:				
Accumulated benefit obligation	$989,688	$905,661	$—	$—
Fair value of plan assets	719,332	658,474	—	—
Post-retirement Plans With an Accumulated Post-retirement Benefit Obligation In Excess of Plan Assets:				
Accumulated post-retirement benefit obligation	$—	$—	$131,549	$129,563
Fair value of plan assets	—	—	124,070	115,619
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Benefit Obligation:				
Discount rate	3.73 %	4.25 %	3.68 %	4.15 %
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. The decrease in the discount rates used as of December 31, 2017, increased the pension and post-retirement benefit obligations by approximately $79.0 million and $7.0 million, respectively.

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.

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	Pension Benefits			Post-retirement Benefits		
Year Ended December 31,	2017	2016	2015	2017	2016	2015
	(Dollars in Thousands)					
Components of Net Periodic Cost (Benefit):						
Service cost	$20,874	$18,563	$21,392	$1,084	$1,084	$1,443
Interest cost	42,482	43,723	43,014	5,255	5,571	5,691
Expected return on plan assets	(43,039)	(42,653)	(40,236)	(6,873)	(6,835)	(6,614)
Amortization of unrecognized:						
Prior service costs	682	768	520	455	455	455
Actuarial loss (gain), net	21,956	20,577	32,131	(780)	(1,118)	379
Net periodic cost (benefit) before regulatory adjustment	42,955	40,978	56,821	(859)	(843)	1,354
Regulatory adjustment (a)	13,425	14,528	6,886	(1,917)	(1,922)	4,096
Net periodic cost (benefit)	$56,380	$55,506	$63,707	$(2,776)	$(2,765)	$5,450
Other Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets and Liabilities:						
Current year actuarial loss (gain)	$38,562	$48,954	$(43,459)	$(5,726)	$3,486	$(9,576)
Amortization of actuarial (loss) gain	(21,956)	(20,577)	(32,379)	780	1,118	(379)
Current year prior service cost	—	(3,397)	5,730	—	—	—
Amortization of prior service costs	(682)	(768)	(520)	(455)	(455)	(455)
Other adjustments	—	—	352	—	—	—
Total recognized in regulatory assets and liabilities	$15,924	$24,212	$(70,276)	$(5,401)	$4,149	$(10,410)
Total recognized in net periodic cost and regulatory assets and liabilities	$72,304	$79,718	$(6,569)	$(8,177)	$1,384	$(4,960)
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost (Benefit):						
Discount rate	4.25 %	4.60 %	4.17 %	4.15 %	4.51 %	4.10 %
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 %	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 and regulatory liabilities into net periodic cost in 2018.

	Pension Benefits	Post-retirement Benefits
	(In Thousands)	
Actuarial loss (gain)	$25,941	$ (539)
Prior service cost	666	455
Total	$26,607	$ (84)

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.

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Plan Assets

We believe 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 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 are instructed 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.

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 approximately 39% to debt securities, 39% to equity securities, 12% to 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 futures related to debt, equity and foreign currency. 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 5, “Financial Instruments and Trading Securities,” for a description of the hierarchal framework.

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The following table provides the fair value of our pension plan assets and the corresponding level of hierarchy as of December 31, 2017 and 2016.

As of December 31, 2017	Level 1	Level 2	Level 3	NAV	Total
	(In Thousands)				
Assets:					
Domestic equity funds	$—	$188,850	$ —	$23,896	$212,746
International equity fund	—	98,646	—	—	98,646
Emerging market equity fund	—	26,804	—	—	26,804
Domestic bond fund	—	100,687	—	—	100,687
Core bond fund	—	98,874	—	—	98,874
High-yield bond fund	—	31,692	—	—	31,692
Emerging market bond fund	—	25,959	—	—	25,959
Combination debt/equity/other fund	—	36,167	—	—	36,167
Alternative investment fund	—	—	—	48,906	48,906
Real estate securities fund	—	—	—	34,421	34,421
Cash equivalents	—	4,430	—	—	4,430
Total Assets Measured at Fair Value	$—	$612,109	$ —	$107,223	$719,332

As of December 31, 2016	Level 1	Level 2	Level 3	NAV	Total
Assets:	(In Thousands)				
Domestic equity funds	$—	$168,407	$ —	$23,580	$191,987
International equity fund	—	83,738	—	—	83,738
Emerging market equity fund	—	21,055	—	—	21,055
Domestic bond fund	—	101,200	—	—	101,200
Core bond fund	—	86,109	—	—	86,109
High-yield bond fund	—	30,729	—	—	30,729
Emerging market bond fund	—	23,584	—	—	23,584
Combination debt/equity/other fund	—	37,851	—	—	37,851
Alternative investment fund	—	—	—	43,686	43,686
Real estate securities fund	—	—	—	32,390	32,390
Cash equivalents	—	6,145	—	—	6,145
Total Assets Measured at Fair Value	$—	$558,818	$ —	$99,656	$658,474

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The following table provides the fair value of our post-retirement benefit plan assets and the corresponding level of hierarchy as of December 31, 2017 and 2016.

As of December 31, 2017	Level 1	Level 2	Level 3	NAV	Total
	(In Thousands)				
Assets:					
Domestic equity funds	$ —	$ 65,187	$ —	$ —	$ 65,187
International equity fund	—	16,217	—	—	16,217
Core bond fund	—	42,083	—	—	42,083
Cash equivalents	—	583	—	—	583
Total Assets Measured at Fair Value	$ —	$ 124,070	$ —	$ —	$ 124,070

As of December 31, 2016	Level 1	Level 2	Level 3	NAV	Total
	(In Thousands)				
Assets:					
Domestic equity funds	$ —	$ 61,055	$ —	$ —	$ 61,055
International equity fund	—	15,034	—	—	15,034
Core bond fund	—	38,952	—	—	38,952
Cash equivalents	—	578	—	—	578
Total Assets Measured at Fair Value	$ —	$ 115,619	$ —	$ —	$ 115,619

Cash Flows

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

	Pension Benefits		Post-retirement Benefits	
	To/(From) Trust	(From) Company Assets	To/(From) Trust	(From) Company Assets
	(In Millions)			
Expected contributions:				
2018	$ 32.4		$ —	
Expected benefit payments:				
2018	$ (57.6)	$ (2.3)	$ (7.9)	$ (0.3)
2019	(60.1)	(2.3)	(8.0)	(0.3)
2020	(62.8)	(2.2)	(8.0)	(0.2)
2021	(65.4)	(2.2)	(8.1)	(0.2)
2022	(65.1)	(2.2)	(8.1)	(0.2)
2023-2027	(331.5)	(10.8)	(38.7)	(0.9)

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 $8.3 million in 2017, $8.0 million in 2016 and $7.7 million in 2015.

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Stock-Based Compensation Plans

We have a long-term incentive and share award plan (LTISA Plan), which is a stock-based compensation plan in which employees and directors are eligible for awards. The LTISA Plan was implemented as a means to attract, retain and motivate employees and directors. Under the LTISA Plan, we may grant awards in the form of stock options, dividend equivalents, share appreciation rights, RSUs, performance shares and performance share units to plan participants. Up to 8.3 million shares of common stock may be granted under the LTISA Plan. As of December 31, 2017, awards of approximately 5.4 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 four years. However, upon consummation of the merger, all unrecognized compensation costs for outstanding RSU awards will be expensed on our income statement. 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,		
	2017	2016	2015
	(In Thousands)		
Compensation expense	$8,869	$9,237	$8,250
Income tax benefits related to stock-based compensation arrangements	3,508	3,653	3,263

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.

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. Nonforfeitable dividend equivalents are recorded directly to retained earnings.

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 2017 valuation, inputs for expected volatility ranged from 17.6% to 22.7% and the risk-free interest rate was approximately 1.5%. For the 2016 valuation, inputs for expected volatility ranged from 16.9% to 22.4% and the risk-free interest rate was approximately 0.9%. 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.

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During the years ended December 31, 2017, 2016 and 2015, our RSU activity for awards with only service requirements was as follows.

	As of December 31,					
	2017		2016		2015	
	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	289.4	$ 40.11	309.9	$ 35.21	342.2	$ 31.38
Granted	79.8	53.25	99.3	46.35	115.7	39.50
Vested	(109.4)	35.56	(115.9)	32.33	(115.4)	28.77
Forfeited	(3.8)	44.08	(3.9)	40.95	(32.6)	33.07
Nonvested balance, end of year	256.0	46.09	289.4	40.11	309.9	35.21

Total unrecognized compensation cost related to RSU awards with only service requirements was $4.7 million and $5.0 million as of December 31, 2017 and 2016, respectively. Absent the merger, 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, 2017, 2016 and 2015, was $6.1 million, $5.2 million and $4.7 million, respectively.

During the years ended December 31, 2017, 2016 and 2015, our RSU activity for awards with performance measures was as follows.

	As of December 31,					
	2017		2016		2015	
	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	297.7	$ 40.79	299.1	$ 36.00	345.1	$ 32.31
Granted	76.4	37.08	100.9	46.03	94.8	40.26
Vested	(106.7)	36.38	(98.5)	31.59	(109.0)	28.99
Forfeited	(2.0)	42.16	(3.8)	41.57	(31.8)	34.03
Nonvested balance, end of year	265.4	41.48	297.7	40.79	299.1	36.00

As of December 31, 2017 and 2016, total unrecognized compensation cost related to RSU awards with performance measures was $3.6 million and $4.5 million, respectively. Absent the merger, we expect to recognize these costs over a remaining weighted-average period of 1.6 years. The total fair value of RSUs with performance measures that vested during the years ended December 31, 2017, 2016 and 2015, was $12.0 million, $7.5 million and $3.1 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 124 shares of common stock for dividends in 2017, 170 shares in 2016 and 296 shares in 2015. Participants received common stock distributions of 1,325 shares in 2017, 2,110 shares in 2016 and 2,024 shares in 2015.

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13. 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,	2017	2016	2017	2016
	(In Thousands)			
Change in Benefit Obligation:				
Benefit obligation, beginning of year	$229,025	$206,418	$ 7,215	$ 7,793
Service cost	7,800	6,748	146	127
Interest cost	9,900	9,655	280	325
Plan participants' contributions	—	—	1,096	989
Benefits paid	(8,381)	(6,974)	(1,623)	(1,531)
Actuarial losses (gains)	23,423	13,178	(99)	(488)
Benefit obligation, end of year	$261,767	$229,025	$ 7,015	$ 7,215
Change in Plan Assets:				
Fair value of plan assets, beginning of year	$138,688	$121,622	$ 17	$ 105
Actual return on plan assets	25,053	8,967	46	(4)
Employer contributions	12,047	14,820	466	458
Plan participants' contributions	—	—	1,096	989
Benefits paid	(8,128)	(6,721)	(1,623)	(1,531)
Fair value of plan assets, end of year	$167,660	$138,688	$ 2	$ 17
Funded status, end of year	$(94,107)	$(90,337)	$ (7,013)	$ (7,198)
Amounts Recognized in the Balance Sheets Consist of:				
Current liability	$(271)	$(248)	$ (552)	$ (538)
Noncurrent liability	(93,836)	(90,089)	(6,461)	(6,660)
Net amount recognized	$(94,107)	$(90,337)	$ (7,013)	$ (7,198)
Amounts Recognized in Regulatory Assets (Liabilities) Consist of:				
Net actuarial loss (gain)	$69,895	$66,324	$ (748)	$ (654)
Prior service cost	391	446	—	—
Net amount recognized	$70,286	$66,770	$ (748)	$ (654)

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As of December 31,	Pension Benefits 2017	2016	Post-retirement Benefits 2017	2016
	(Dollars in Thousands)			
Pension Plans With a Projected Benefit Obligation In Excess of Plan Assets:				
Projected benefit obligation	$261,767	$229,025	$—	$—
Fair value of plan assets	167,660	138,688	—	—
Pension Plans With an Accumulated Benefit Obligation In Excess of Plan Assets:				
Accumulated benefit obligation	$229,883	$201,963	$—	$—
Fair value of plan assets	167,660	138,688	—	—
Post-retirement Plans With an Accumulated Post-retirement Benefit Obligation In Excess of Plan Assets:				
Accumulated post-retirement benefit obligation	$—	$—	$ 7,015	$ 7,215
Fair value of plan assets	—	—	2	17
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Benefit Obligation:				
Discount rate	3.73 %	4.26 %	3.56 %	3.95 %
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 decrease in the discount rates used as of December 31, 2017, increased Wolf Creek's pension and post-retirement benefit obligations by approximately $19.5 million and $0.2 million, respectively.

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The prior service cost is amortized on a straight-line basis over the average future service of the active employees (plan participants) benefiting under the plan at the time of the amendment. The net actuarial 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,	2017	2016	2015	2017	2016	2015
	(Dollars in Thousands)					
Components of Net Periodic Cost (Benefit):						
Service cost	$7,800	$6,748	$7,595	$146	$127	$138
Interest cost	9,900	9,655	9,016	280	325	314
Expected return on plan assets	(10,571)	(9,722)	(9,044)	—	—	—
Amortization of unrecognized:						
Prior service costs	55	55	57	—	—	—
Actuarial loss (gain), net	4,979	4,357	5,930	(50)	(14)	3
Curtailments, settlements, and special termination benefits	390	—	—	—	—	—
Net periodic cost before regulatory adjustment	12,553	11,093	13,554	376	438	455
Regulatory adjustment (a)	1,083	1,886	(1,485)	—	—	—
Net periodic cost	$13,636	$12,979	$12,069	$376	$438	$455
Other Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets and Liabilities:						
Current year actuarial loss (gain)	$8,550	$13,934	$(2,373)	$(145)	$(484)	$(211)
Amortization of actuarial (gain) loss	(4,979)	(4,357)	(5,930)	50	14	(3)
Amortization of prior service cost	(55)	(55)	(57)	—	—	—
Total recognized in regulatory assets and liabilities	$3,516	$9,522	$(8,360)	$(95)	$(470)	$(214)
Total recognized in net periodic cost and regulatory assets and liabilities	$17,152	$22,501	$3,709	$281	$(32)	$241
Weighted-Average Actuarial Assumptions used to Determine Net Periodic Cost:						
Discount rate	4.26%	4.61%	4.20%	3.95%	4.27%	3.89%
Expected long-term return on plan assets	7.25%	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 and regulatory liabilities into net periodic cost in 2018.

	Pension Benefits	Post-retirement Benefits
	(In Thousands)	
Actuarial loss (gain)	$6,624	$(58)
Prior service cost	55	—
Total	$6,679	$(58)

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.

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

	As of December 31,	
	2017	2016
Health care cost trend rate assumed for next year	6.0 %	6.5 %
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	2020	2020

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)	$ 10
Effect on post-retirement benefit obligation	(133)	142

Plan Assets

Wolf Creek's 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 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 are instructed 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 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.

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 5, "Financial Instruments and Trading Securities," for a description of the hierarchal framework.

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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, 2017 and 2016.

As of December 31, 2017	Level 1	Level 2	Level 3	NAV	Total
	(In Thousands)				
Assets:					
Domestic equity funds	$—	$43,396	$—	$—	$43,396
International equity funds	—	52,485	—	—	52,485
Core bond funds	—	42,304	—	—	42,304
Real estate securities fund	—	—	—	7,415	7,415
Alternative investment fund	—	16,988	—	4,369	21,357
Cash equivalents	—	703	—	—	703
Total Assets Measured at Fair Value	$—	$155,876	$—	$11,784	$167,660

As of December 31, 2016	Level 1	Level 2	Level 3	NAV	Total
	(In Thousands)				
Assets:					
Domestic equity funds	$—	$34,586	$—	$—	$34,586
International equity funds	—	43,269	—	—	43,269
Core bond funds	—	35,048	—	—	35,048
Real estate securities fund	—	—	—	6,948	6,948
Alternative investment fund	—	14,073	—	4,164	18,237
Cash equivalents	—	600	—	—	600
Total Assets Measured at Fair Value	$—	$127,576	$—	$11,112	$138,688

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:				
2018	$8.9		$ 0.6	
Expected benefit payments:				
2018	$(8.0)	$ (0.3)	$ (2.0)	$ —
2019	(9.0)	(0.3)	(2.3)	—
2020	(9.9)	(0.3)	(2.6)	—
2021	(10.8)	(0.3)	(2.9)	—
2022	(11.7)	(0.3)	(3.2)	—
2023 - 2027	(70.7)	(1.9)	(19.7)	—

Savings Plan

Wolf Creek maintains a qualified 401(k) savings plan in which most of its employees participate. Wolf Creek matches 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 2017, $1.6 million in 2016 and $1.6 million in 2015.

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14. 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 and Purchased Power 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, 2017, was as follows.

	Committed Amount (In Thousands)
2018	$ 257,544
2019	17,787
2020	4,842
Thereafter	3,172
Total amount committed	$ 283,345

Environmental Matters

Set forth below are descriptions of contingencies related to environmental matters that may impact us or our financial results. Our assessment of these contingencies, which are based on federal and state statutes and regulations, and regulatory agency and judicial interpretations and actions, has evolved over time. There are a variety of final and proposed laws and regulations that could have a material adverse effect on our operations and consolidated financial results. Due in part to the complex nature of environmental laws and regulations, we are unable to assess the impact of potential changes that may develop with respect to the environmental contingencies described below.

Federal Clean Air Act

We must comply with the federal Clean Air Act (CAA), 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.

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 the majority of our fossil fuel 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 2017, we had adequate SO_2 allowances to meet generation and we expect to have enough to cover emissions under this program in 2018.

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Cross-State Air Pollution Update Rule

In September 2016, the EPA finalized the Cross-State Air Pollution Update Rule. The final rule addresses interstate transport of NOx emissions in 22 states including Kansas, Missouri and Oklahoma during the ozone season and the impact from the formation of ozone on downwind states with respect to the 2008 ozone National Ambient Air Quality Standards (NAAQS). Starting with the 2017 ozone season, the final rule revised the existing ozone season allowance budgets for Missouri and Oklahoma and established an ozone season budget for Kansas. Various states and others are challenging the rule in the U.S. Court of Appeals for the D.C. Circuit but the rule remains in effect. We do not believe this rule will have a material impact on our operations and consolidated financial results.

National Ambient Air Quality Standards

Under the federal CAA, the EPA sets NAAQS for certain emissions known as the “criteria pollutants” considered harmful to public health and the environment, including two classes of PM, ozone, nitrogen dioxide (NO_2) (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.

In October 2015, the EPA strengthened the ozone NAAQS by lowering the standards from 75 ppb to 70 ppb. In September 2016, the KDHE recommended to the EPA that they designate eight counties in the state of Kansas as in attainment with the standard, and each remaining county in Kansas as attainment/unclassifiable. In November 2017, EPA designated all counties in the State of Kansas as attainment/unclassifiable. We do not believe this will have a material impact on our consolidated financial results.

Various states and others are challenging the revised 2015 ozone NAAQS in the D.C. Circuit. In April 2017, at the request of the EPA, the court issued an order holding the case in abeyance because the new administration is planning to review the 2015 ozone NAAQS and will determine whether to reconsider all or a portion of the rule. In December 2017, environmental groups filed suit against the EPA for failure to make all the required area designations by an October 2017 deadline. Also in December 2017, the EPA issued a notice of availability of their intent to issue the remainder of the area designations by April 2018. This will not affect the area designations for Kansas issued in November 2017.

In December 2012, the EPA strengthened an existing NAAQS for one class of PM. In December 2014, the EPA designated the entire state of Kansas as attainment/unclassifiable with the standard. We do not believe this will have a material impact on our operations or consolidated financial results.

In 2010, the EPA revised the NAAQS for SO_2. In March 2015, a federal court approved a consent decree between the EPA and environmental groups. The decree includes specific SO_2 emissions criteria for certain electric generating plants that, if met, required the EPA to promulgate attainment/nonattainment designations for areas surrounding these plants. Tecumseh Energy Center is our only generating station that meets these criteria. In June 2016, the EPA accepted the State of Kansas recommendation to designate the areas surrounding the facility as unclassifiable. In addition, in January 2017, KDHE formally recommended to the EPA a 2,000 ton per year limit for Tecumseh Energy Center Unit 7 in order to satisfy the requirements of the 1-hour SO_2 Data Requirements Rule that governs the next round of the designations. Also in January 2017, KDHE recommended the EPA change the designation of the area surrounding the facility from unclassifiable to attainment/unclassifiable. In August 2017, the EPA indicated they would address this area redesignation request in a separate action. By agreeing to the 2,000 ton per year limitation, no further characterization of the area surrounding the plant is required.

We continue to communicate with our regulatory agencies regarding these standards and evaluate what impact the revised NAAQS could have on our operations and consolidated financial results. If areas surrounding our facilities are designated in the future as nonattainment and/or we are required to install additional equipment to control emissions at our facilities, it could have a material impact on our operations and consolidated financial results.

Greenhouse Gases

Burning coal and other fossil fuels releases carbon dioxide (CO_2) and other gases referred to as greenhouse gas (GHG). Various regulations under the federal CAA 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.

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In October 2015, the EPA published a rule establishing new source performance standards (NSPS) for GHGs that limit CO_2 emissions for new, modified and reconstructed coal and natural gas fueled electric generating units to various levels per Megawatt hour (MWh) depending on various characteristics of the units. Legal challenges to the GHG NSPS have been filed in the D.C. Circuit by various states and industry members. Also in October 2015, the EPA published a rule establishing guidelines for states to regulate CO_2 emissions from existing power plants. The standards for existing plants are known as the Clean Power Plan (CPP). Under the CPP, interim emissions performance rates must be achieved beginning in 2022 and final emissions performance rates must be achieved by 2030. Legal challenges to the CPP were filed by groups of states and industry members, including us, in the D.C. Circuit.

In April 2017, the EPA published in the Federal Register a notice of withdrawal of the proposed CPP federal plan, proposed model trading rules and proposed Clean Energy Incentive Program design details. Also in April 2017, the EPA published a notice in the Federal Register that it is initiating administrative reviews of the CPP and the GHG NSPS.

In October 2017, the EPA issued a proposed rule to repeal the CPP. The proposed rule indicates the CPP exceeds EPA's authority and the EPA has not determined whether or not they will issue a replacement rule. The EPA is soliciting comments on the legal interpretations contained in this rulemaking.

In December 2017, the EPA issued an advance notice of proposed rulemaking. This proposed rulemaking was issued by the EPA because it is considering the possibility of changing certain aspects of the CPP and the EPA is soliciting feedback on specific areas that could be changed. Comments on these proposed areas of change are due to the EPA in February 2018.

Due to the future uncertainty of the CPP, we cannot determine the impact on our operations or consolidated financial results, but we believe the cost to comply with the CPP, should it be upheld and implemented in its current or a substantially similar form, 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 were issued in November 2015. The final rule establishes effluent limitations guidelines (ELG) and standards for wastewater discharges, including limits on the amount of toxic metals and other pollutants that can be discharged. Implementation timelines for these requirements vary from 2019 to 2023. In April 2017, the EPA announced it is reconsidering the ELG rule and court challenges have been placed in abeyance pending the EPA's review. In September 2017, the EPA finalized a rule to postpone the compliance dates for the new, more stringent, effluent limitations and pretreatment standards for bottom ash transport water and flue gas desulfurization wastewater. These compliance dates have been postponed for two years while the EPA completes its administrative reconsideration of the ELG rule. We are evaluating the final rule and related developments and cannot predict the resulting impact on our operations or consolidated financial results, but believe costs to comply could be material if the rule is implemented in its current or substantially similar form.

In October 2014, the EPA's final standards for cooling intake structures at power plants to protect aquatic life took effect. The standards, based on Section 316(b) of the federal Clean Water Act (CWA), require subject facilities to choose among seven best available technology options to reduce fish impingement. In addition, some facilities must conduct studies to assist permitting authorities to determine whether and what site-specific controls, if any, would be required to reduce entrainment of aquatic organisms. Our current analysis indicates this rule will not have a significant impact on our coal plants that employ cooling towers or cooling lakes that can be classified as closed cycle cooling. We do not expect the impact from this rule to be material.

In June 2015, the EPA along with the U.S. Army Corps of Engineers issued a final rule, effective August 2015, defining the Waters of the United States (WOTUS) for purposes of the CWA. This rulemaking has the potential to impact all programs under the CWA. Expansion of regulated waterways is possible under the rule depending on regulating authority interpretation, which could impact several permitting programs. Various states and others have filed lawsuits challenging the WOTUS rule. In July 2017, the EPA and the U.S. Army Corps of Engineers published in the Federal Register a proposed rule that would, if implemented, reinstate the definition of WOTUS that existed prior to the June 2015 expansion of the definition. Final action on the proposed rule is expected in early 2018. We are currently evaluating the WOTUS rule and related developments. We do not believe the rule, if upheld and implemented in its current or substantially similar form, will have a material impact on our operations or consolidated financial results.

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Regulation of Coal Combustion Residuals

In the course of operating our coal generation plants, we produce coal combustion residuals (CCRs), including fly ash, gypsum and bottom ash. We recycle some of our ash production, principally by selling to the aggregate industry. The EPA published a rule to regulate CCRs in April 2015, which we believe will require additional CCR handling, processing and storage equipment and closure of certain ash disposal ponds. Impacts to operations will be dependent on the development of groundwater monitoring of CCR units being completed in 2017 and 2018. The Water Infrastructure Improvements for the Nation Act allows states to achieve delegated authority for CCR rules from the EPA. This has the potential to impact compliance options. Electric generation industry participants requested and the EPA has granted a request to reconsider portions of the final CCR regulation. The EPA has stated its intent to propose a rule in early 2018 to modify portions of the 2015 rulemaking. We have recorded an ARO for our current estimate for closure of ash disposal ponds but we may be required to record additional AROs in the future due to changes in existing CCR regulations, changes in interpretation of existing CCR regulations or changes in the timing or cost to close ash disposal ponds. If additional AROs are necessary, we believe the impact on our operations or consolidated financial results could be material. See Note 15, “Asset Retirement Obligations,” for additional information.

SPP Revenue Crediting

We are a member of the Southwest Power Pool, Inc. (SPP) RTO, which coordinates the operation of a multi-state interconnected transmission system. In 2016, the SPP completed a process of allocating revenue credits under its Open Access Transmission Tariff to sponsors of certain transmission system upgrades. Qualifying upgrades are generation interconnection or transmission service projects that benefit SPP members and that are paid for directly by a sponsor without customer support. The SPP determined sponsors are entitled to revenue credits for previously completed upgrades, and members are obligated to pay for revenue credits attributable to these historical upgrades. As a result, in November 2016 we paid the SPP $7.6 million related to revenue credits attributable to historical upgrades from March 2008 to August 2016. The SPP issued revised allocations and we received a small refund in November 2017.

Nuclear Decommissioning

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

The KCC reviews nuclear decommissioning plans in two phases. Phase one is the approval of the updated 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 2017, Wolf Creek updated the nuclear decommissioning cost study. Based on the study, our share of decommissioning costs, including decontamination, dismantling and site restoration, is estimated to be approximately $380.0 million. This amount compares to the prior site study estimate of $360.0 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 $5.8 million in 2017, $5.0 million in 2016 and $2.8 million in 2015. We record our investment in the NDT fund at fair value, which approximated $237.1 million and $200.1 million as of December 31, 2017 and 2016, respectively.

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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. 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. The NRC has not yet issued its decision.

Wolf Creek is currently evaluating alternatives for expanding its existing on-site spent nuclear fuel storage to provide additional capacity prior to 2025. Wolf Creek has finalized a settlement agreement through 2019 with the DOE for reimbursement of costs to construct this facility that would not have otherwise been incurred had the DOE begun accepting spent nuclear fuel. As a co-owner of Wolf Creek, we received $0.8 million of the settlement representing reimbursement of costs incurred through 2015 for project planning. Wolf Creek submitted a settlement claim to the DOE in August 2017 for costs incurred between January 2016 and June 2017, with our share of the claim being approximately $0.5 million. We cannot predict when, or if, an off-site storage site or alternative disposal site will be available to receive Wolf Creek’s spent nuclear fuel and will continue to monitor this activity.

Nuclear Insurance

We maintain nuclear liability, property and accidental outage 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 for nuclear events ($1.8 billion of non-nuclear events) plus any reinsurance, indemnity or any other source recoverable by Nuclear Electric Insurance Limited (NEIL), our property and accidental outage 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. In addition, we are required to participate in industry-wide retrospective assessment programs as discussed below.

Nuclear Liability Insurance

Pursuant to the Price-Anderson Act, we insure against public nuclear liability claims resulting from nuclear incidents to the required limit of public liability, which is approximately $13.4 billion. This limit of liability consists of the maximum available commercial insurance of $450.0 million and the remaining $13.0 billion is provided through mandatory participation in an industry-wide retrospective assessment program. Under this retrospective assessment program, the owners of Wolf Creek are jointly and severally subject to an assessment of up to $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 for any commercial U.S. nuclear reactor qualifying incident. Both the total and yearly assessment is subject to an inflationary adjustment every five years with the next adjustment in 2018. In addition, Congress could impose additional revenue-raising measures to pay claims.

Nuclear Property and Accidental Outage Insurance

The owners of Wolf Creek carry decontamination liability, nuclear property damage and premature nuclear decommissioning liability insurance for Wolf Creek totaling approximately $2.8 billion. Insurance coverage for non-nuclear property damage accidents total approximately $2.3 billion. In the event of an extraordinary nuclear 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 help 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 $37.4 million (our share is $17.6 million).

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Nuclear Insurance Considerations

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 and Purchased Power Commitments

To supply a portion of the fuel requirements for our power plants, the owners of Wolf Creek have entered into various 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, 2017, our share of Wolf Creek’s nuclear fuel commitments was approximately $13.4 million for uranium concentrates expiring in 2024, $1.9 million for conversion expiring in 2024, $83.2 million for uranium hexafluoride expiring in 2024, $69.9 million for enrichment expiring in 2027 and $31.4 million for fabrication expiring in 2025.

As of December 31, 2017, our coal and coal transportation contract commitments under the remaining terms of the contracts were approximately $489.7 million. The contracts are for plants that we operate and expire at various times through 2020.

As of December 31, 2017, our natural gas transportation contract commitments under the remaining terms of the contracts were approximately $92.6 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 power purchase agreements with the owners of nine separate wind generation facilities with installed design capabilities of approximately 1,328 MW expiring in 2028 through 2036. 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 $140.0 million.

15. 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 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. 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 or an offset to a regulatory liability.

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, close ash landfills and dispose of polychlorinated biphenyl (PCB)-contaminated oil. ARO refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement may be conditional on a future event that may or may not be within the control of the entity. In determining our AROs, we make assumptions regarding probable future disposal costs. A change in these assumptions could have significant impact on the AROs reflected on our consolidated balance sheet.

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The following table summarizes our legal AROs included on our consolidated balance sheets.

	As of December 31,	
	2017	2016
	(In Thousands)	
Beginning balance	$323,951	$275,285
Increase in ARO liabilities	13,471	—
Liabilities settled	(16,026)	(5,372)
Accretion expense	16,940	14,165
Revision to nuclear decommissioning ARO liability	19,377	—
Revisions in estimated cash flows	47,405	39,873
Ending balance	$405,118	$323,951
Less: amount included in other current liabilities	25,129	—
Long-term AROs	$379,989	$323,951

Wolf Creek filed a nuclear decommissioning cost study with the KCC in 2017. As a result of the study, we recorded a $19.4 million increase in our ARO to reflect revisions to the estimated costs to decommission Wolf Creek. In addition, we increased our AROs for asbestos by $28.8 million and recorded a new ARO liability of approximately $13.5 million related to Western Plains Wind Farm. In 2016, we increased our ARO by $39.9 million to recognize costs associated with closure and post-closure of ash disposal ponds in response to the EPAs rule to regulate CCRs. See Note 14, “Commitments and Contingencies - Regulation of Coal Combustion Residuals,” for additional information on the CCR rule.

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

The initial retirement obligation related to asbestos disposal was recorded in 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 and ash disposal ponds at several of our power plants. The retirement obligations for the ash landfills and ash disposal ponds were 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, 2017, we had $30.8 million in amounts spent, but not yet collected, for removal costs classified as a regulatory asset. As of December 31, 2016, we had $5.7 million in amounts collected, but not yet spent, for removal costs classified as a regulatory liability.

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16. LEGAL PROCEEDINGS

We and our subsidiaries are involved in various legal, environmental and regulatory proceedings. We believe that adequate provisions have been made and accordingly believe that the ultimate disposition of such matters will not have a material effect on our consolidated financial results. See Notes 4 and 14, “Rate Matters and Regulation” and “Commitments and Contingencies,” for additional information.

Pending Merger

Following the announcement of the original merger agreement in May 2016, two putative class action petitions (which were consolidated and superseded by a consolidated class action petition) and one putative derivative petition challenging the original merger were filed in the District Court of Shawnee County, Kansas. In September 2016, the plaintiffs in both actions agreed in principle to dismiss the actions in exchange for our agreement to make supplemental disclosures to shareholders in connection with the original merger agreement and grant waivers of the prohibition on requesting a waiver of the standstill provisions in the confidentiality and standstill agreements executed by the bidders that participated in a sale process that was conducted as part of the original merger agreement. As described below, after the announcement of the revised merger agreement, the plaintiffs in the consolidated putative class action moved to amend their petition, and the plaintiff in the putative derivative case refiled his petition.

The consolidated putative class action petition, originally filed July 25, 2016, is captioned In re Westar Energy, Inc. Stockholder Litigation, Case No. 2016-CV-000457. This petition named as defendants Westar Energy, the members of our board of directors and Great Plains Energy.

On September 25, 2017, the lead plaintiff filed a motion for leave to amend her class action petition and attached an amended petition. The petition as amended now includes an additional plaintiff. The petition challenges the revised proposed merger and alleges a claim of breach of fiduciary duty against our board of directors and a claim of aiding and abetting that alleged breach against us and Great Plains Energy. The lawsuit seeks injunctive relief declaring the action maintainable as a class action and certifying that the plaintiffs are the class representatives; preliminarily and permanently enjoining the defendants from closing the merger unless we implement a procedure to obtain a merger agreement providing fair and reasonable terms and consideration to the plaintiffs and the class; rescinding the merger agreement or granting the plaintiffs and the class rescissory damages; directing our board of directors to account to the plaintiffs and the class for damages suffered as a result of the alleged breach of fiduciary duty; awarding the plaintiffs reasonable costs and disbursements of the action, including reasonable attorneys’ fees and expert fees; and granting other equitable relief as the court deems proper. The petition alleges inadequacies in our joint proxy statement concerning the revised proposed transaction and the degree to which our board of directors solicited or considered offers from prior bidders after the proposed original merger was denied by the KCC, and claims that the consideration our stockholders stand to receive in connection with the revised proposed transaction is unfair. Plaintiffs have added two new defendants, Monarch Energy Holding, Inc. and King Energy, Inc., whom they allege aided and abetted our board of directors in breaching their fiduciary duties.

On October 18, 2017, the putative derivative petition, captioned Braunstein v. Chandler et al., Case No. 2017-CV-000692, was re-filed in the District Court of Shawnee County, Kansas. This putative derivative action names as defendants the members of our board of directors, Great Plains Energy, and subsidiaries of Great Plains Energy, with Westar Energy named as a nominal defendant. The petition asserts that the members of our board of directors breached their fiduciary duties to our shareholders in connection with actions taken after the KCC rejected the proposed original merger. It also asserts that Great Plains Energy and subsidiaries of Great Plains Energy aided and abetted such breaches of fiduciary duties. The petition alleges, among other things, that the members of our board of directors failed to obtain the best possible price for our shareholders because of a flawed process that discouraged third parties from submitting potentially superior proposals, and that members of our board of directors committed waste by not collecting termination fees that may have been payable following the KCC's rejection of the original merger agreement. The petition seeks, among other remedies, an order enjoining the merger on the terms proposed and directing that the director defendants exercise their fiduciary duties to obtain a transaction, which is in the best interests of us and our shareholders, a declaration that the proposed merger was entered into in breach of the fiduciary duties of the defendants and is therefore unlawful and unenforceable, rescission of the merger agreement if consummated, the imposition of a constructive trust in favor of the plaintiff, on behalf of us, upon any benefits improperly received by the named defendants as a result of their wrongful conduct, and an award for costs, including attorneys' fees and experts' fees.

In addition, on September 21, 2017, a putative class action lawsuit was filed in the United States District Court for the District of Kansas, captioned David Pill v. Westar Energy, Inc. et al, Civil Action No. 17-4086. The federal class action complaint challenges the merger and alleges violations of sections 14(a) and 20(a) of the Securities Exchange Act of 1934, as amended (Exchange Act). The complaint seeks an order declaring that the action is maintainable as a class action and

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certifying that the plaintiff is the class representative; preliminarily and permanently enjoining defendants from consummating the mergers or, if consummated, setting them aside and awarding rescissory damages; directing the defendants to file a registration statement on Form S-4 that corrects alleged misstatements; directing our board of directors to account to plaintiff and the class for their damages; awarding reasonable costs and disbursements of the action, including reasonable attorneys' fees and expert fees; and granting other further relief as the court deems proper.

On October 6, 2017, another putative class action lawsuit was filed in the United States District Court for the District of Kansas, captioned Robert L. Reese v. Westar Energy, Inc. et al, Civil Action No. 2:17-cv-02584. This federal class action complaint challenges the proposed merger and alleges violations of sections 14(a) and 20(a) of the Exchange Act. The complaint seeks an order enjoining the board and other parties from proceeding with, consummating, or closing the merger or, if consummated, setting it aside and awarding rescissory damages; directing the board to disseminate a registration statement that corrects alleged misstatements and includes all material facts the plaintiff asserts are missing; declaring that the defendants violated sections 14(a) and 20(a) of the Exchange Act and Rule 14a-9; awarding reasonable costs and disbursements of the action, including reasonable attorneys' fees and expert fees; and granting other equitable relief as the court deems proper.

On November 16, 2017, the parties in each of the actions independently agreed to withdraw requests for injunctive relief and otherwise agreed in principle to dismissing the actions with prejudice and to providing releases, in exchange for the supplemental disclosures that we filed in a Form 8-K on November 16, 2017. These agreements do not constitute any admission by any of the defendants as to the merits of any claims. In the future, the parties will prepare and present to the court for approval Stipulations of Settlement that will, if accepted by the court, settle the actions in their entirety. The outcome of litigation is inherently uncertain. The defense or settlement of any lawsuit or claim that remains unresolved at the time the merger closes may adversely affect the combined company's business, financial condition or results of operation.

17. COMMON STOCK

General

Westar Energy's Restated Articles of Incorporation, as amended, provide for 275.0 million authorized shares of common stock. As of December 31, 2017 and 2016, Westar Energy had issued 142.1 million shares and 141.8 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 2017 and 2016, Westar Energy issued 0.4 million shares through the DSPP and other stock-based plans operated under the long-term incentive and share award plan. As of December 31, 2017 and 2016, a total of 0.9 million shares and 1.0 million shares, respectively, were available under the DSPP registration statement.

Issuances

In March 2013, Westar Energy entered into a three-year sales agency financing agreement and master forward sale agreement with a bank. Both agreements expired in March 2016. The maximum amount that Westar Energy could have offered and sold under the master agreement was 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 could have offered and sold shares of its common stock from time to time. The agent received a commission equal to 1% of the sales price of all shares sold under the agreements. In 2015, we settled 9.2 million shares for a physical settlement of approximately $254.6 million.

The forward sale transactions were entered into at market prices; therefore, the forward sale agreements had no initial fair value. Westar Energy did not receive any proceeds from the sale of common stock under the forward sale agreements until transactions were settled. Westar Energy settled the forward sale transactions through physical share settlement and recorded the forward sale agreements within equity. The shares under the forward sale agreements were initially priced when the transactions were entered into and were subject to certain fixed pricing adjustments during the term of the agreements. The net proceeds from the forward sale transactions represent the prices established by the forward sale agreements applicable to the time periods in which physical settlement occurred.

Westar Energy used the proceeds from the transactions described above to repay short-term borrowings, with such borrowed amounts principally used for investments in capital equipment, as well as for working capital and general corporate purposes.

18. 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. The primary beneficiary of a VIE is required to consolidate the VIE. The trust holding our 50% interest in La Cygne unit 2 is a VIE. The trust holding our 8% interest in Jeffrey Energy Center was a VIE until the expiration of a purchase option in July 2017. We remain the primary beneficiary of the trust holding our 50% interest in La Cygne unit 2.

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 VIE 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 met the requirements to be considered the primary beneficiary of the trust until July 2017, when a contractual option to purchase the 8% interest in the plant covered by the lease expired. Accordingly, we deconsolidated the trust in the third quarter of 2017.

In determining the primary beneficiary of the trust, we concluded at the inception of the lease that the activities of the trust that most significantly impacted its economic performance and that we had the power to direct included (1) the operation and maintenance of the 8% interest in JEC, (2) our ability to exercise an option that expired in July 2017 to purchase the plant 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 had 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 was greater than the fixed amount. The possibility of lower interest rates upon refinancing the debt also created 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 and (2) our ability to exercise a purchase option at the end of the agreement 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 50% interest in La Cygne unit 2 at the end of the agreement is greater than the fixed amount.

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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,	
	2017	2016
	(In Thousands)	
Assets:		
Property, plant and equipment of variable interest entities, net	$176,279	$257,904
Regulatory assets (a)	—	10,396
Liabilities:		
Current maturities of long-term debt of variable interest entities	$28,534	$26,842
Accrued interest (b)	659	867
Long-term debt of variable interest entities, net	81,433	111,209

(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.

19. LEASES

Operating Leases

We lease office buildings, computer equipment, vehicles, railcars and other property and equipment. 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:	
2015	$ 14,035
2016	13,563
2017	15,661
Future commitments:	
2018	$ 18,132
2019	13,263
2020	9,411
2021	7,448

2022	4,505
Thereafter	5,900
Total future commitments	$ 58,659

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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.

Assets recorded under capital leases are listed below.

	As of December 31,	
	2017	2016
	(In Thousands)	
Vehicles	$19,679	$15,595
Computer equipment	924	1,073
Generation plant	40,048	40,048
Accumulated amortization	(17,091)	(13,542)
Total capital leases	$43,560	$43,174

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)
2018	$ 6,433
2019	5,856
2020	5,213
2021	4,699
2022	4,092
Thereafter	49,811
	76,104
Amounts representing imputed interest	(27,434)
Present value of net minimum lease payments under capital leases	48,670
Less: Current portion	3,809
Total long-term obligation under capital leases	$ 44,861

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20. 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.

2017	First	Second	Third	Fourth
	(In Thousands, Except Per Share Amounts)			
Revenues (a)	$572,574	$609,321	$794,327	$594,781
Net income (a)	63,482	76,039	160,724	36,306
Net income attributable to Westar Energy, Inc. (a)	59,661	72,065	158,306	33,888
Per Share Data (a):				
Basic:				
Earnings available	$0.42	$0.50	$1.11	$0.24
Diluted:				
Earnings available	$0.42	$0.50	$1.11	$0.24
Cash dividend declared per common share	$0.40	$0.40	$0.40	$0.40
Market price per common share:				
High	$56.60	$55.12	$53.49	$57.32
Low	$52.16	$50.35	$49.20	$49.95

(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.

2016	First	Second	Third	Fourth
	(In Thousands, Except Per Share Amounts)			
Revenues (a)	$569,450	$621,448	$764,654	$606,535
Net income (a)	68,708	76,144	158,553	57,795
Net income attributable to Westar Energy, Inc. (a)	65,585	72,340	154,720	53,932
Per Share Data (a):				
Basic:				
Earnings available	$0.46	$0.51	$1.09	$0.38
Diluted:				
Earnings available	$0.46	$0.51	$1.08	$0.38
Cash dividend declared per common share	$0.38	$0.38	$0.38	$0.38
Market price per common share:				
High	$50.38	$57.25	$56.95	$57.50
Low	$40.01	$48.92	$52.52	$54.41

(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.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

We maintain a set of disclosure controls and procedures designed to ensure that information required to be disclosed in reports that we file or submit under the Securities Exchange Act of 1934, as amended (Exchange Act), is recorded, processed, summarized and reported within the time periods specified in SEC 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 Exchange Act is accumulated and communicated to management, including the chief executive officer and the chief financial officer, allowing timely decisions regarding required disclosure. As of the end of the period covered by this report, based on an evaluation carried out under the supervision and with the participation of management, including the chief executive officer and the chief financial officer, of the effectiveness of our disclosure controls and procedures, the chief executive officer and the chief financial officer have concluded that our disclosure controls and procedures were effective.

There were no changes in our internal control over financial reporting during the three months ended December 31, 2017, that 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 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

Investors should note that we announce material financial information in SEC filings, press releases and public conference calls. In accordance with SEC guidance, we may also use the Investor Relations section of our website (http://www.WestarEnergy.com, under “Investors”) to communicate with investors about our company. It is possible that the financial and other information we post there could be deemed to be material information. The information on our website is not part of this document.

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PART III

Information required by Items 10-14 of Part III of this Form 10-K will be incorporated by reference to our definitive proxy statement with respect to our 2018 Annual Meeting of Shareholders (2018 Proxy Statement), if such definitive proxy statement is filed with the SEC on or before April 30, 2018. Due to the pending Merger with Great Plains Energy, we may not be required to file the 2018 Proxy Statement, in which case we will file an amendment to this Form 10-K on or before April 30, 2018, to include the information that is otherwise incorporated by reference.

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 2018 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 2018 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 captions Election of Directors - Corporate Governance Matters and - Board Meetings and Committees of the Board of Directors in our 2018 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 2018 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 2018 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 2018 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 2018 Proxy Statement under the caption of Ratification and Confirmation of Deloitte and Touche LLP as Our Independent Registered Public Accounting Firm for 2018 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.

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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, 2017 and 2016
Consolidated Statements of Income for the years ended December 31, 2017, 2016 and 2015
Consolidated Statements of Cash Flows for the years ended December 31, 2017, 2016 and 2015
Consolidated Statements of Changes in Equity for the years ended December 31, 2017, 2016 and 2015
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

2	Agreement and Plan of Merger, dated as of May 29, 2016, by and among Westar Energy, Inc., Great Plains Energy Incorporated and a subsidiary of Great Plains Energy Incorporated (filed as Exhibit 2.1 to the Form 8-K filed on May 31, 2016) (schedules have been omitted pursuant to Item 601(b)(2) of Regulation S-K, and Westar Energy will furnish the omitted schedules to the Securities and Exchange Commission upon request)	I
2(a)	Amended and Restated Merger Agreement, dated as of July 9, 2017, by and among Westar Energy, Inc., Great Plains Energy Incorporated, Monarch Energy Holding, Inc., King Energy, Inc. and, solely for the purposes set forth therein, GP Star, Inc. (filed as Exhibit 2.1 to the Form 8-K filed on July 10, 2017)	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

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3(i)	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(j)	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(k)	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(l)	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, 2011 filed on February 23, 2012)	I
4(a)	Mortgage and Deed of Trust dated July 1, 1939 between Westar Energy, Inc. and Harris Trust and Savings Bank, Trustee (filed as Exhibit 4(a) to Registration Statement No. 33-21739)	I
4(b)	First and Second Supplemental Indentures dated July 1, 1939 and April 1, 1949, respectively (filed as Exhibit 4(b) to Registration Statement No. 33-21739)	I
4(c)	Sixth Supplemental Indenture dated October 4, 1951 (filed as Exhibit 4(b) to Registration Statement No. 33-21739)	I
4(d)	Fourteenth Supplemental Indenture dated May 1, 1976 (filed as Exhibit 4(b) to Registration Statement No. 33-21739)	I
4(e)	Twenty-Eighth Supplemental Indenture dated July 1, 1992 (filed as Exhibit 4(o) to the Form 10-K for the period ended December 31, 1992 filed on March 30, 1993)	I
4(f)	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(g)	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(h)	Form of Senior Note (included in Exhibit 4(g))	I
4(i)	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(j)	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(k)	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(l)	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(m)	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(n)	Form of Forty-Third Supplemental Indenture, dated as of March 28, 2013, by and among 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(o)	Form of Forty-Fourth Supplemental Indenture, dated as of August 19, 2013, by and among 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(p)	Form of Forty-Fifth Supplemental Indenture, dated as of November 13, 2015, by and among Westar Energy, Inc. and The Bank of New York Mellon Trust Company, N.A., as successor to Harris Trust and Savings Bank (filed as Exhibit 4.1 to the Form 8-K filed on November 6, 2015)	I
4(q)	Form of Forty-Sixth Supplemental Indenture, dated as of June 20, 2016, by and among Westar Energy, Inc. and The Bank of New York Mellon Trust Company, N.A., as successor to Harris Trust and Savings Bank	I

	(filed as Exhibit 4.1 to the Form 8-K filed on June 17, 2016)	
4(r)	Form of Forty-Seventh Supplemental Indenture, dated as of March 6, 2017, by and among Westar Energy, Inc. and The Bank of New York Mellon Trust Company, N.A., as successor to Harris Trust and Savings Bank (filed as Exhibit 4.1 to the Form 8-K filed on March 3, 2017)	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

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10(b)	Amended and Restated Long-Term Incentive and Share Award Plan (filed as Exhibit 10 to the Form 8-K filed on May 6, 2011)*	I
10(c)	Amended and Restated Long-Term Incentive and Share Award Plan, effective January 1, 2016 (filed as Appendix B to the Proxy Statement filed on April 1, 2016)*	I
10(d)	Westar Energy, Inc. Form of Restricted Share Units Award (Grant Date February 24, 2016) (filed as Exhibit 10(f) to the Form 10-K for the period ended December 31, 2014 filed on February 25, 2015)*	I
10(e)	Westar Energy, Inc. Form of Performance Based Restricted Share Units Award (Grant Date February 24, 2016) (filed as Exhibit 10(g) to the Form 10-K for the period ended December 31, 2014 filed on February 25, 2015)*	I
10(f)	Westar Energy, Inc. Form of Restricted Share Units Award (Grant Dates February 22, 2017 Forward) (filed as Exhibit 10(f) to the Form 10-K for the period ended December 31, 2016 filed on February 22, 2017)*	I
10(g)	Westar Energy, Inc. Form of Performance Based Restricted Share Units Award (Grant Dates February 22, 2017 Forward) (filed as Exhibit 10(g) to the Form 10-K for the period ended December 31, 2016 filed on February 22, 2017)*	I
10(h)	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(i)	Summary of Westar Energy, Inc. Non-Employee Director Compensation (filed as Exhibit 10(f) to the Form 10-K for the period ended December 31, 2015 filed on February 24, 2016)*	I
10(j)	Form of Amended and Restated Change in Control Agreement with Officers of Westar Energy, Inc. (filed as Exhibit 10(g) to the Form 10-K for the period ended December 31, 2015 filed on February 24, 2016)*	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)	Westar Energy, Inc. 401(k) Benefit Restoration Plan (filed as Exhibit 10(l) to the Form 10-K for the period ended December 31, 2014 filed on February 25, 2015)*	I
10(m)	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(n)	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(o)	Second Extension Agreement dated as of February 14, 2014, 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(v) to the Form 10-K for the period ended December 31, 2013 filed on February 26, 2014)	I
10(p)	First Amendment to Credit Agreement and Lender Joinder Agreement, dated December 19, 2016, by and among Westar Energy, Inc. and the several banks and other financial institutions or entities from time to time parties thereto (filed as Exhibit 10.1 to the Form 8-K filed on December 20, 2016)	I
10(q)	Second Amendment to Credit Agreement, dated December 14, 2017, by and among Westar Energy, Inc. and the several banks and other financial institutions or entities from time to time parties thereto (filed as Exhibit 10.1 to the Form 8-K filed on December 14, 2017)	I
10(r)	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(s)	First Extension Agreement dated as of July 19, 2013, 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(a) to	I

	the Form 10-Q for the period ended September 30, 2014 filed on November 5, 2014)	
10(t)	Second Extension Agreement dated as of September 18, 2014, 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(b) to the Form 10-Q for the period ended September 30, 2014 filed on November 5, 2014)	I
10(u)	Third Extension Agreement dated as of September 17, 2015, 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 to the Form 10-Q for the period ended September 30, 2015 filed on November 3, 2015)	I
10(v)	Amendment Agreement, dated December 19, 2016, by and among Westar Energy, Inc. and the several banks and other financial institutions or entities from time to time parties thereto (filed as Exhibit 10.2 to the Form 8-K filed on December 20, 2016)	I
10(w)	Second Amendment Agreement, dated December 14, 2017, by and among Westar Energy, Inc. and the several banks and other financial institutions or entities from time to time parties thereto (filed as Exhibit 10.2 to the Form 8-K filed on December 14, 2017)	I
12	Computations of Ratio of Consolidated Earnings to Fixed Charges	#
21	Subsidiaries of the Registrant	#

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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 Financial 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	#

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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, 2015				
Allowances deducted from assets for doubtful accounts	$5,309	$ 8,614	$ (8,629)	$ 5,294
Year ended December 31, 2016				
Allowances deducted from assets for doubtful accounts	$5,294	$ 12,197	$ (10,824)	$ 6,667
Year ended December 31, 2017				
Allowances deducted from assets for doubtful accounts	$6,667	$ 10,509	$ (10,460)	$ 6,716

(a) Result from write-offs of accounts receivable.

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ITEM 16. FORM 10-K SUMMARY
None.

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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 21, 2018	By:	/s/ ANTHONY D. SOMMA Anthony D. Somma Senior Vice President, Chief Financial Officer and Treasurer

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SIGNATURES

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

Signature	Title	Date
/S/ MARK A. RUELLE (Mark A. Ruelle)	Director, President and Chief Executive Officer (Principal Executive Officer)	February 21, 2018
/S/ ANTHONY D. SOMMA (Anthony D. Somma)	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial and Accounting Officer)	February 21, 2018
/S/ CHARLES Q. CHANDLER IV (Charles Q. Chandler IV)	Chairman of the Board	February 21, 2018
/S/ MOLLIE H. CARTER (Mollie H. Carter)	Director	February 21, 2018
/S/ R. A. EDWARDS III (R. A. Edwards III)	Director	February 21, 2018
/S/ JERRY B. FARLEY (Jerry B. Farley)	Director	February 21, 2018
/S/ RICHARD L. HAWLEY (Richard L. Hawley)	Director	February 21, 2018
/S/ B. ANTHONY ISAAC (B. Anthony Isaac)	Director	February 21, 2018
/S/ SANDRA A. J. LAWRENCE (Sandra A. J. Lawrence)	Director	February 21, 2018
/S/ S. CARL SODERSTROM JR. (S. Carl Soderstrom Jr.)	Director	February 21, 2018