Public Version

KANSAS CITY POWER & LIGHT COMPANY
Before the State Corporation Commission of Kansas
Docket No. 18-KCPE-XXX-RTS

KANSAS CITY POWER & LIGHT COMPANY
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Docket No. 18-KCPE-XXX-RTS

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SECTION 1
APPLICATION, LETTER OF TRANSMITTAL, AND AUTHORIZATION

BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

In the Matter of the Application of Kansas City Power & Light Company to Make Certain Changes in Its Charges for Electric Service	)))	Docket No.: 18-KCPE-___-RTS

APPLICATION

COMES NOW Kansas City Power & Light Company ("KCP&L" or the "Company") and, pursuant to K.S.A. 66-117 and K.A.R. 82-1-231, hereby respectfully requests authorization from the State Corporation Commission of the State of Kansas ("Commission") to make certain changes in its charges for electric service in Kansas and approve other requests as set forth herein. KCP&L respectfully requests that the proposed rate changes become effective in accordance with the statute and regulation. In support of this Application, KCP&L states the following:

I. THE COMPANY

1. KCP&L is a Missouri corporation and a vertically integrated electric public utility company under the jurisdiction of the Commission that is engaged in the production, transmission, delivery and furnishing of power within the meaning of K.S.A. 66-104, in legally designated areas of Kansas. KCP&L holds a certificate of convenience and authority issued by the Commission, authorizing KCP&L to engage in such utility business. KCP&L has previously filed with the Commission certified copies of its Articles of Incorporation under which it was organized, its Certificate of Registration as a Foreign Corporation authorized to do business in Kansas, and all amendments thereto and restatements thereof, and the same are incorporated herein by reference.

II. DESCRIPTION OF THE COMPANY'S REQUESTS

2. This Application presents KCP&L's request for rate adjustments necessary to cover rising costs of providing electric service, including investment in plant and infrastructure to support safe, reliable service to our customers, accounting treatment proposals, and rate design changes.

3. An increase in rates for providing electric service to its customers in Kansas is needed in order to afford KCP&L the opportunity to cover its costs of providing service to its customers and to earn a fair and reasonable return on its investor-supplied capital. The schedules filed with this Application establish a gross revenue requirement deficiency of $26.2 million, excluding the rebasing of property taxes, based upon normalized operating results for the test year ending September 30, 2017, adjusted for known and measurable changes in revenues, operating and maintenance expenses, cost of capital and taxes, and other adjustments explained in the testimony and schedules supporting this Application. The Company's requested increase is $32.9 million with the inclusion of property tax rebasing. KCP&L requests authorization to increase its Kansas electric rates to cover this deficiency. This represents an overall rate increase of approximately 4.53 percent (5.70 percent with the inclusion of property tax rebasing) based on a current Kansas jurisdictional base revenue requirement of $577.9 million.

4. KCP&L's current electric rates were established in Docket No. 17-KCPE-201-RTS ("2017 Abbreviated Rate Case").[1] That case was an abbreviated rate filing[2] approved by the Commission in Docket No. 15-GIME-025-MIS ("15-025 Docket").[3] The 2017 Abbreviated

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1 *See* In the Matter of the Application of Kansas City Power & Light Company to Make Certain Changes in Its Charges for Electric Service, 17-201 Docket, Order Approving Unanimous Stipulation and Agreement, (issued June 6, 2017) ("17-201 Order").

2 As provided for under K.A.R.82-1-231(b)(3).

3 15-025 Docket, Order Approving Joint Application, issued Sep. 9, 2014, Ordering ¶ C.

Rate Case, filed on November 9, 2016, was abbreviated in that it adjusted rates to true-up the costs of construction of environmental upgrades at the LaCygne Generating Station and the Wolf Creek capital addition costs to actual costs along with all affected components of KCP&L's revenue requirement. The 2017 Abbreviated Rate Case updated the amortization of Wolf Creek refueling outage costs included in base rates to refueling outage 20 expenditures. The 2017 Abbreviated Rate Case also incorporated into KCP&L's rates updates to certain regulatory asset and liability amortizations. Since the 2017 Abbreviated Rate Case, the Company's overall cost of service has increased. KCP&L is seeking an increase in rates because its revenues are not adequate to cover its operating costs and a fair and reasonable return on rate base investment. Notwithstanding the Company's efforts to contain costs, this disparity will only increase as KCP&L continues working to meet the various federal and state mandated costs, and to meet its customers' reliability requirements.

5. As addressed in the Direct Testimony of Company witnesses Mr. Darrin R. Ives and Ron Klote, in addition to general increases in the cost of providing electric service, there are three primary reasons requiring the need to file this Application (i) recovery of certain costs for plant additions including the addition of the new CIS billing system; (ii) the filing of a new depreciation study per Commission Order; and (iii) the Tax Cuts and Jobs Act of 2017 has significantly decreased the revenue requirement calculated in this case. KCP&L believes that its customers should benefit from the reduction in corporate federal income tax rates.

6. The Company is asking for an authorized return on equity ("ROE") of 9.85 percent based upon a capital structure of 50.84 percent equity. As explained in the testimony of KCP&L witness Robert B. Hevert, this recommendation results in a total rate of return of 7.39 percent.

III. DRIVERS OF THE CHANGE IN KCP&L'S REVENUE REQUIREMENT

7. The first driver of KCP&L's revenue requirement change is the Tax Cuts and Jobs Act of 2017 ("TCJA"), which reduces KCP&L's revenue requirement by $34.5 million. This includes the impact from reduced tax rate going forward as well as the return of a portion of KCP&L's accumulated deferred income taxes to customers. In addition, as discussed in the testimony of Darrin Ives, KCP&L is also proposing to return the net reduction in its cost of service caused by the corporate tax rate change between January 1, 2018, and the date new rates become effective as a result of this application.

8. Another driver of KCP&L's request is the installation of a new customer information system ("CIS") to replace the aging legacy billing system and other functionality such as customer self-service (the "One CIS Solution Project"). As explained in the testimony of Charles Caisley and Forrest Archibald, the Company had to undertake the One CIS Solution Project because the legacy system was no longer supported by certain vendors and it did not provide the functionality to efficiently serve customers. The revenue requirement effect associated with the One CIS Solution Project as well as other plant additions needed to serve customers is approximately $33.6 million.

9. The third driver is an increase in depreciation expense, which is the result of a Commission-mandated study[4] of depreciation rates to ensure that they reflect reasonable levels consistent with fully and appropriately allocating the recovery of KCP&L's investments made to serve customers. The revenue requirement impact associated with the depreciation study is approximately 24 million.

[4] The Commission required that "the natural gas and public utilities shall file a depreciation study on their assets every five to seven years and may be filed concurrent with a rate case. Order Closing Docket, Docket No. 08-GIMX-1142-GIV (Aug. 1, 2013), ¶ 8.

10. Great Plains Energy Incorporated ("GPE") and KCP&L's application for approval of the merger of GPE with Westar, Energy, Inc. is currently pending before the Commission. Commission approval of the Settlement Agreement proposed in that proceeding would reduce the revenue requirement, and resulting rates, requested by KCP&L in this Application. Briefly, those revenue requirement reductions are as follows:

- Reduction in requested return on equity from 9.85% to 9.3% ($8.8 million)
- Guaranteed level of merger savings to be included in cost of service ($1.025 million)
- Reduction in transition cost recovery ($0.7 million)

11. The revenue requirement reductions that would result from Commission approval of the Settlement Agreement in Docket No. 18-KCPE-095-MER are described in more detail in the Direct Testimony of Mr. Darrin Ives and Mr. Ronald Klote. If the Commission approves that Settlement Agreement, KCP&L will file Supplemental Direct Testimony in this docket shortly thereafter reducing the overall revenue requirement, and resulting rates, requested in this proceeding.

IV. RATE DESIGN PROPOSALS

12. The Company is making several rate design proposals including proposed pilot programs for the implementation of demand and Time of Use ("TOU") rates. In conjunction with the TOU pilot programs, the Company is seeking approval of two new Energy Efficiency programs to assist in educating customers who sign up for the pilot programs. In addition, the proposed Solar Subscription Pilot Rider and Renewable Energy Rider provide increased access to renewable energy for those customers who wish to participate. The Company is also proposing a new demand rate for residential distributed generation customers and a new Standby

tariff for Commercial & Industrial customers utilizing their own generation sources. The Company is proposing to eliminate its obsolete Real-Time Pricing rate. Finally, the Company proposes changes to its electric vehicle charging tariff to better meet the needs of electric vehicle users. These changes are discussed in the testimony of witnesses Tim Rush, Marisol Miller, Brad Lutz and Kim Winslow.

V. TESTIMONY AND SCHEDULES

13. This Application and the attached schedules and testimony filed on behalf of KCP&L in this proceeding reflect historical data and analyses concerning KCP&L's operations based on a test year ending September 30, 2017; test year data was also annualized and normalized and reflects projected values for known and measurable changes up to the expected audit cut-off date of June 30, 2018. The proposed rates and other requests in this Application are just and reasonable, and necessary to assure continuing, adequate, efficient and reliable utility service.

14. The testimony of 14 witnesses and the schedules required by K.A.R. 82-1-231 are filed in support of this Application. As discussed below, certain confidential information has been redacted from testimony, schedules and exhibits where appropriate, pursuant to K.S.A. 66-1220a. The names and the subject of each witness' testimony are as follows:

Forrest Archibald	One CIS Solution Project
Albert R. Bass	Weather Normalization; Customer Annualization of Unit Sales
Charles A. Caisley	Clean Charge Network; One CIS Solution Project
Robert B. Hevert	Return on Equity; Cost of Capital; Cost of Debt; Capital Structure; and Overall Rate of Return
Darrin R. Ives	Company and Case Overview/ Policy Return on Equity; Merger Impact

Ronald A. Klote	Revenue Requirement Schedules; Accounting Adjustments
Bradley D. Lutz	Production Allocation; Renewable Energy Programs
Marisol Miller	Minimum Filing Requirements; Annualized/Normalized Revenues; Class Cost of Service and Rate Design
Linda Nunn	Accounting Adjustments
Tim Rush	Electric Vehicle Charging Station Tariff; ECA
Thomas Sullivan	Production Cost Allocation
Jessica Tucker	Fuel Inventory
Dane A. Watson	Depreciation
Kimberly Winslow	TOU rates pilot programs; Renewable Energy Programs; Energy Efficiency Programs

15. Certain information contained in the testimony has been designated by KCP&L as "confidential". KCP&L requests that the Commission maintain the confidential status of such designated materials in accordance with K.S.A. 66-1220a, K.S.A. 66-1233 and K.A.R. 82-1-221a. The public disclosure of such information would adversely impact the financial interests of KCP&L and/or the security of KCP&L's assets. A separate public version of this filing with the confidential information redacted has also been filed with the Commission. The information designated as confidential in this filing and the basis for the designation are identified in the attached Confidential Information Worksheet.

VI. PROCEDURAL MATTERS

16. Data requests concerning this Application should be addressed to Regulatory.Affairs@kcpl.com.

VII. SERVICE

17. In addition to the undersigned, all correspondence, pleadings, orders, decisions and communications regarding this proceeding should be sent to:

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WHEREFORE, KCP&L respectfully requests that the Commission:

(1) Approve the proposed rate schedules and tariffs for electric service, and order that they become effective as proposed;

(2) Approve the TOU pilot programs proposed by KCP&L to promote energy efficiency;

(3) Approve continued use by KCP&L of the Pension/Other Post Employment Benefit tracker approved by the Commission in Docket No. 07-GIMX-1041-GIV;

(4) Approve the depreciation rates proposed by the Company;

(5) Grant such other and further relief as may be identified during the course of this docket and as the Commission deems just and reasonable.

Respectfully submitted,

/s/ Roger W. Steiner

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ATTORNEYS FOR
KANSAS CITY POWER & LIGHT COMPANY

VERIFICATION

STATE OF MISSOURI)
) ss.
COUNTY OF JACKSON)

I, Darrin R. Ives, being duly sworn, on oath state that I am Vice President – Regulatory Affairs of Kansas City Power & Light Company, that I have read the foregoing Application and know the contents thereof, and that the facts set forth therein are true and correct to the best of my knowledge and belief.

KANSAS CITY POWER & LIGHT COMPANY

By: ______________________
Darrin R. Ives

The foregoing Application was subscribed and sworn to before me this May 1, 2018.

____
Notary Public

My Commission Expires:

4/26/2021

ANTHONY R WESTENKIRCHNER
Notary Public, Notary Seal
State of Missouri
Platte County
Commission # 17279952
My Commission Expires April 26, 2021

SECTION 2
GENERAL INFORMATION AND PUBLICITY

Kansas City Power & Light Company
Retail Revenue Summary - Kansas
Information Filed in Accordance with K.A.R. 82-1-231
Test Year Ending September 30, 2017

	iii	iii						i		iv		
Line No.	**Classification**	**Average Number of WN-EE-Current Customers**	**WN-EE-Current kWh**	**WN-EE-Current Revenue**	**Average Price per kWh**	**Proposed Revenue**	**Proposed Price per kWh ****	**Proposed Revenue Increase**	**Proposed Percent Increase (%)**	**Average Monthly Increase per Customer**	**Proposed Increase ($) per kWh ****	**Average Monthly kWh Usage per Customer**
1	Residential	224,099	2,847,796,936	$ 295,423,478	$ 0.10374	$ 320,319,759	$ 0.11248	$ 24,896,281	8.43%	$ 9.26	$ 0 00874	1,059
2	Small General Service	23,226	379,290,426	$ 43,958,196	$ 0.11590	$ 45,211,338	$ 0.11590	$ 1,253,142	2.85%	$ 4.50	$ -	1,361
3	Medium General Service	3,970	758,322,278	$ 69,285,911	$ 0.09137	$ 71,261,085	$ 0 09137	$ 1,975,174	2.85%	$ 41.46	$ -	15,918
4	Large General Service	1,145	2,366,184,952	$ 162,402,701	$ 0.06863	$ 167,032,410	$ 0 06863	$ 4,629,709	2.85%	$ 337.02	$ -	172,249
6	Other (Lighting and Traffic Signals)	4,205	54,013,182	$ 6,827,468	$ 0.12640	$ 7,022,102	$ 0.13001	$ 194,635	2.85%	$ 3.86	$ 0 00360	1,070
7	**Subtotal Retail (Billed)**	**256,645**	**6,405,607,774**	**$ 577,897,754**	**$ 0.09022**	**$ 610,846,694**	**$ 0.09536**	**$ 32,948,941**	**5.70%**	**$ 10.70**	**$ 0.00514**	**2,080**
8	Adjustments	(2 549) *										
9	**Total Retail (Billed)**	**254,096**	**6,405,607,774**	**$ 577,897,754**	**$ 0.09022**	**$ 610,846,694**	**$ 0.09536**	**$ 32,948,941**	**5.70%**	**$ 10.81**	**$ 0.00514**	**2,101**

**Area lights not included in total customer count*
*** No revenue increase was applied to the energy rates for Small GS, Medium, GS, and Large GS.*

Section 2(i, iii - iv)
Amount of Proposed Aggregate Annual Revenue Increase
Number and Classification of Customers to be Affected
Average Dollar/Cents Per Customer Increase Sought

Confidential information
designated by "**_**"

NAMES OF COMMUNITIES AFFECTED

Anderson County
Garnett
Greeley

Bourbon County
Fulton
Mapleton

Coffey County
Waverly

Douglas County
Baldwin

Franklin County
Lane
Ottawa
Princeton
Rantoul
Richmond
Wellsville
Williamsburg

Johnson County
Edgerton
Fairway
Gardner
Lake Quivira
Leawood
Lenexa
Merriam
Mission
Mission Hills
Mission Woods
Olathe
Overland Park
Prairie Village
Roeland Park
Shawnee
Spring Hill
Westwood
Westwood Hills

Leavenworth County

Linn County
Lacygne
Linn Valley
Mound City
Parker
Pleasanton

Miami County
Fontana
Louisburg
Osawatomie
Paola
Spring Hill

Osage County
Lyndon
Melvern
Quenemo

Wyandotte County
Bonner Springs
Edwardsville
Kansas City

Kansas City Power & Light Company
Docket No. 18-KCPE-xxx-RTS
Summary of Reasons for Filing This Rate Application

Test Year: October 1, 2016 through September 30, 2017
Including Known and Measurable Changes through June 30, 2018

Kansas City Power & Light Company ("KCP&L"), a subsidiary of Great Plains Energy, Inc., files this Application with the State Corporation Commission of the State of Kansas ("Commission" or "KCC"), and requests approval to increase rates for electric service.

KCP&L's rates were last adjusted on June 28, 2017 by Order of the Commission issued on June 6, 2017 in Docket No. 17-KCPE-201-RTS. This resulted in a total decrease to KCP&L's retail jurisdictional rates in Kansas of $3.6 million or approximately (0.62%). The increase from this current Application is expected to be effective December 27, 2018.

In addition to general increases in the cost of providing electric service, there are three primary reasons KCP&L is filing this Application. First, to receive recovery of certain costs for plant additions since the last full general rate review request in Docket No. 15-KCPE-116-RTS which included plant investment updates through March of 2015. Included in the plant investments in this case is the addition of the new Customer Information System. Secondly, this rate case filing includes the filing of a new depreciation study filed in conjunction with the rate case per Commission Order. Finally, the Tax Cuts and Jobs Act of 2017 has significantly decreased the revenue requirement calculation. KCP&L believes that its customers should benefit from the reduction in corporate federal income tax rates. The filing of this general rate review will provide those benefits.

Finally, KCP&L is requesting adjustments to its rate design.

NEWS RELEASE

MEDIA CONTACT:
KCP&L 24-hour Media Hotline
(816) 392-9455

FOR IMMEDIATE RELEASE

KCP&L FILES RATE UPDATE REQUEST WITH KANSAS CORPORATION COMMISSION

If approved, rate updates would include federal tax cut savings and several customer experience enhancements.

KANSAS CITY, Mo. (May 1, 2018) — KCP&L, a subsidiary of Great Plains Energy Incorporated (NYSE: GXP), today requested a rate update for its Kansas customers. This request will update rates for several customer experience enhancements, including technology and green initiatives. Additionally, the company is asking to pass along 100 percent of the savings resulting from the Tax Cuts and Jobs Act to customers. This will result in approximately $34.5 million in ongoing annual savings for KCP&L's customers in Kansas. The Federal Energy Regulatory Commission recently approved KCP&L's request to return the portion of tax reform savings set at the federal level to customers as quickly as possible.

Once savings from the Tax Cuts and Jobs Act are taken into account, KCP&L is requesting approximately a 4.5 percent, or $26.2 million increase to its rates for KCP&L-Kansas customers.

Separately, KCP&L and Westar are requesting approval of a merger and related settlement agreement from the Kansas Corporation Commission (KCC). If the merger and settlement agreement are approved, these two neighboring utilities will combine into a stronger regional company, creating value for all customers and communities in a way neither company could on its own. If the merger and settlement agreement are approved while this rate update request is pending, KCP&L's Kansas customers will benefit from one-time savings of $39.3 million and ongoing annual savings of $18.3 million. For more information about the merger, please visit www.kcpl.com/Westar.

The rate update process takes approximately eight months in Kansas, so any resulting rate changes would be expected to be effective in late December 2018. If the rate update is approved as filed, before benefits resulting from KCC approval of the merger and settlement agreement, the average residential customer* living in the KCP&L-Kansas service area would see an approximately $7.30 per month change. To better understand the area impacted by this rate update request, please visit www.kcpl.com/servicearea.

Customer-Focused Enhancements

Over the last few years, KCP&L has worked to bring innovative energy solutions to its customers. Many of these solutions allow customers the flexibility to manage and receive information about their energy usage in a way that fits their needs, whether in-person, online or over the phone.

One notable innovative project for customers is KCP&L's **new customer information system**, which is scheduled to launch later this week. This system and its related technologies ensure improved, consistent and more efficient customer communications. In other words, customers want to hear from KCP&L in helpful and relevant ways; these new technologies help meet that customer need. The new customer information system includes cyber security upgrades to further protect customers' personal information.

"Our customers have asked us to continue and enhance the information and tools available to help them save money and make informed decisions about their energy usage," said Terry Bassham, KCP&L President and CEO. "These technology enhancements are providing exactly what customers want: the information they need, when and where they want it."

Sustainability Investments

In addition to technology enhancements, KCP&L is also investing in sustainable ways to deliver electricity to customers. One such project is the KCP&L Clean Charge Network, KCP&L's electric vehicle charging program. This network has made the region the fastest growing for electric vehicle adoption in the country. Additionally, the Clean Charge Network is making the air cleaner for everyone living and working in the area.

KCP&L is also requesting several additional ways for customers to power their homes and businesses with renewable energy. Today, approximately 17 percent of KCP&L's generation capacity comes from renewable sources like wind and solar and nearly 43 percent of the energy used to meet KCP&L's retail energy demand is carbon-free. If approved, the proposed Renewable Energy and Solar Subscription programs would provide customers with options to directly subscribe to receive renewable energy to offset the energy they use each month.

"In addition to technology that enhances when and where we provide information, our customers also expect clean energy to be a part of how we power their lives," said Bassham. "Whether it's electricity from sources like solar and wind or an innovative electric vehicle charging network, we have and will continue to be committed to sustainable ways to meet our customers' energy needs."

Customer Assistance

Most of the customer bill impact of the costs associated with these investments is largely offset by the federal tax savings. However, KCP&L offers several resources and partners with community agencies to help customers who struggle to pay their electricity bill. Visit our billing and payment options online or contact KCP&L at 1-888-471-5275 to discuss available payment options.

For more information on this rate update request, visit www.kcpl.com/KSRates.

** An average residential customer uses 1366 kWh in a summer month and 833 kWh in winter month. An average small commercial customer uses 1442 kWh in a summer month and 1156 kWh in a winter month.*

***The launch of the customer information is subject to change due to weather or other unforeseen conditions.*

####

About Great Plains Energy:

Headquartered in Kansas City, Mo., Great Plains Energy Incorporated (NYSE: GXP) is the holding company of Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company, two of the leading regulated providers of electricity in the Midwest. Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company use KCP&L as a brand name. More information about the companies is available on the Internet at: www.greatplainsenergy.com or www.kcpl.com.

Forward-Looking Statements:

Statements made in this release that are not based on historical facts are forward-looking, may involve risks and uncertainties, and are intended to be as of the date when made. Forward-looking statements include, but are not limited to, statements relating to the anticipated merger transaction of Great Plains Energy and Westar Energy, Inc.(Westar), including those that relate to the expected financial and operational benefits of the merger to the companies and their shareholders (including cost savings, operational efficiencies and the impact of the anticipated merger on earnings per share), the expected timing of closing, the outcome of regulatory proceedings, cost estimates of capital projects, dividend growth, share repurchases, balance sheet and credit ratings, rebates to customers, employee issues and other matters affecting future operations. In connection with the safe harbor provisions of the Private Securities Litigation Reform Act of 1995, Great Plains Energy and KCP&L are providing a number of important factors that could cause actual results to differ materially from the provided forward-looking information. These important factors include: future economic conditions in regional, national and international markets and their effects on sales, prices and costs; prices and availability of electricity in regional and national wholesale markets; market perception of the energy industry, Great Plains Energy, KCP&L and Westar; changes in business strategy, operations or development plans; the outcome of contract negotiations for goods and services; effects of current or proposed state and federal legislative and regulatory actions or developments, including, but not limited to, deregulation, re-regulation and restructuring of the electric utility industry; decisions of regulators regarding rates that the Companies can charge for electricity; adverse changes in applicable laws, regulations, rules, principles or practices governing tax, accounting and environmental matters including, but not limited to, air and water quality; financial market conditions and performance including, but not limited to, changes in interest rates and credit spreads and in availability and cost of capital and the effects on derivatives and hedges, nuclear decommissioning trust and pension plan assets and costs; impairments of long-lived assets or goodwill; credit ratings; inflation rates; effectiveness of risk management policies and procedures and the ability of counterparties to satisfy their contractual commitments; impact of terrorist acts, including, but not limited to, cyber terrorism; ability to carry out marketing and sales plans; weather conditions including, but not limited to, weather-related damage and their effects on sales, prices and costs; cost, availability, quality and deliverability of fuel; the inherent uncertainties in estimating the effects of weather, economic conditions and other factors on customer consumption and financial results; ability to achieve generation goals and the occurrence and duration of planned and unplanned generation outages; delays in the anticipated in-service dates and cost increases of generation, transmission, distribution or other projects; Great Plains Energy's and Westar's ability to successfully manage and integrate their respective transmission joint ventures; the inherent risks associated with the ownership and operation of a nuclear facility including, but not limited to, environmental, health, safety, regulatory and financial risks; workforce risks, including, but not limited to, increased costs of retirement, health care and other benefits; the ability of Great Plains Energy and Westar to obtain the regulatory approvals necessary to complete the anticipated merger or the imposition of adverse conditions or costs in connection with obtaining regulatory approvals; the risk that a condition to the closing of the anticipated merger may not be satisfied or that the anticipated merger may fail to close; the outcome of any legal proceedings, regulatory proceedings or enforcement matters that may be instituted relating to the anticipated merger; the costs incurred to consummate the anticipated merger; the possibility that the expected value creation from the anticipated 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 anticipated merger; disruption from the anticipated merger making it more difficult to maintain relationships with customers, employees, regulators or suppliers; the diversion of management time and attention on the anticipated merger; and other risks and uncertainties.

This list of factors is not all-inclusive because it is not possible to predict all factors. Additional risks and uncertainties are detailed from time to time in Great Plains Energy's and KCP&L's quarterly reports on Form 10-Q and annual report on Form 10-K filed with the Securities and Exchange Commission. Each forward-looking statement speaks only as of the date of the particular statement. Great Plains Energy and KCP&L undertake no obligation to publicly update or revise any forward-looking statement, whether as a result of new information, future events or otherwise.

SECTION 3

SUMMARY OF RATE BASE, OPERATING INCOME AND RATE OF RETURN

Kansas City Power & Light Company
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Revenue Requirement - Schedule 1

Line No.	Description	Amount
1	Net Orig Cost of Rate Base (Sch 2)	$ 2,329,018,289
2	Rate of Return	7.3835%
3	Net Operating Income Requirement	171,963,065
4	Net Income Available (Sch 9)	147,755,483
5	Additional NOIBT Needed	24,207,583
6	Additional Current Tax Required	8,741,358
7	Gross Revenue Requirement	**$ 32,948,941**
	% increase:	
	Including ECA	**4.65%**
	Excluding ECA	**5.70%**

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Rate Base - Schedule 2

Line No.	Line Description	Amount	Juris Factor #	Juris Allocator	Electric Retail Rate Base
	A	B	C	D	E
1	***Total Plant :***				
2	Total Plant in Service - Schedule 3	$ 9,906,396,780	Various	See Sch 3	$ 4,586,347,518
3	***Subtract from Total Plant:***				
4	Depreciation Reserve - Schedule 6	3,723,288,675	Various	See Sch 6	1,764,056,647
5	**Net (Plant in Service)**	$ 6,183,108,106			$ 2,822,290,871
6	***Add to Net Plant:***				
7	Cash Working Capital - Schedule 8	(38,547,174)	100% KS	See Sch 8	$ (38,547,174)
8	Materials and Supplies - Schedule 12	124,834,514	Blended	See Sch 12	58,514,223
9	Prepayments - Schedule 12	12,940,498	Blended	See Sch 12	6,064,209
10	Fuel Inventory - Oil - Schedule 12	8,622,812	Blended	See Sch 12	3,758,641
11	Fuel Inventory - Coal - Schedule 12	54,607,361	Blended	See Sch 12	23,803,076
12	Fuel Inventory - Additives - Schedule 12	1,001,016	Blended	See Sch 12	436,338
13	Fuel Inventory - Nuclear - Schedule 12	55,346,650	Blended	See Sch 12	24,125,328
14	Regulatory Asset - Iatan 1 and Com-KS	2,948,807	100% KS	100.000%	2,948,807
15	Regulatory Asset - La Cygne Environ-KS	2,631,856	100% KS	100.000%	2,631,856
16	CWIP	176,104,385	PTD	46.271%	81,485,621
17	***Subtract from Net Plant:***				
18	Cust Advances for Construction-KS	2,109,759	100% KS	100.000%	2,109,759
19	Customer Deposits-KS	1,808,988	100% KS	100.000%	1,808,988
20	Deferred Income Taxes - Schedule 13	1,346,636,554	Blended	See Sch 13	630,337,674
21	Def Gain on SO2 Emissions Allowances-KS	24,216,283	100% KS	100.000%	24,216,283
22	Def Gain (Loss) Emissions Allow-Allocated	47,721	E1	43.590%	20,801
23	**Total Rate Base**	$ 5,208,779,526			$ 2,329,018,289

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12 Month Revenues and O & M Expenses - Schedule 9

Line No.	Account No.	Description	Per Books Test Year	Rate Case Adj	Adjusted Balance	Juris Factor #	Juris Allocator	Electric Juris Adjusted Balance
	A	B	C	D	E	F	G	H
1		**ELECTRIC - RETAIL SALES**						
2	400	Missouri (excluding GRT)	922,340,199	0	922,340,199	100% MO	0 0000%	0
3		Gross Receipts Tax in MO Revenue	72,139,181	0	72,139,181	100% MO	0 0000%	0
4		Amort of Off Syst Sales Margin Rate Refund	758 974	0	758 974	100% MO	0 0000%	0
5		TOTAL MISSOURI	995,238,354	0	995,238,354			0
6		Kansas	737,867,916	(29,481,934)	708,385,982	100% KS	100 0000%	708,385,982
7		**TOTAL RETAIL SALES**	1,733,106,270	(29,481,934)	1,703,624,336			708 385 982
8		**MISCELLANEOUS REVENUE**						
9	450	Forfeited Discounts - MO	2,178,591	0	2,178,591	100% MO	0 0000%	0
10		Forfeited Discounts - KS	1 598 065	96 517	1 694 582	100% KS	100 0000%	1 694 582
11	451	Miscellaneous Services - MO	566,867	0	566,867	100% MO	0 0000%	0
12		Miscellaneous Services - KS	399,838	0	399,838	100% KS	100 0000%	399,838
13		Miscellaneous Services - Allocated - Dist	(36,449)	0	(36,449)	Dist Plt	44.3024%	(16,148)
14	454	Rent from Electric Property - MO	1,911,266	0	1,911,266	100% MO	0 0000%	0
15		Rent from Electric Property - KS	1,963,695	0	1,963,695	100% KS	100 0000%	1,963,695
16		Rent from Electric Property - Allocated - Prod	28,625	0	28,625	D1	47.0659%	13,473
17		Rent from Electric Property - Allocated - Trans	6,785	(6,785)	0	D1	47.0659%	0
18		Rent from Electric Property - Allocated - Dist	0	0	0	Dist Plt	44.3024%	0
19	456	456100 Transmission for Others	16,078,018	(16,078,018)	0	D1	47.0659%	0
20		Other Elec Revenues - Allocated - Transmission	(15,724)	0	(15,724)	D1	47.0659%	(7,401)
21		Other Elec Revenues - MO	811,376	0	811,376	100% MO	0 0000%	0
22		Other Elec Revenues - KS	137,920	0	137,920	100% KS	100 0000%	137,920
23		Other Elec Revenues - Allocated - Dist	0	0	0	Dist Plt	44.3024%	0
24		**TOTAL MISCELLANEOUS REVENUE**	25,628,873	(15,988,286)	9,640,587			4,185,959
25		**BULK POWER SALES (BPS)**						
26	447	Firm Bulk Sales (Capacity & Fixed)	2,947,598	0	2,947,598	E1	43.5895%	1,284,843
27		Firm Bulk Sales (Energy)	113,026,646	0	113,026,646	E1	43.5895%	49,267,750
28		Other Miscellaneous & Adjustments	0	0	0	E1	43.5895%	0
29		Non-firm Sales (margin on sales) **	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted] **
30		Non-firm Sales (cost of sales & other) **	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted] **
31		**TOTAL BULK POWER SALES**	115,974,244	0	115,974,244			50,552,593
32		**SALES FOR RESALE (FERC JURIS CUST)**						
33	447	FERC JURIS WHOLESALE FIRM POWER	0	0	0	NonJur/Wh	0 0000%	0
34		TRANSMISSION FOR FERC WHSLE F RM POWER		0	0	NonJur/Wh	0 0000%	0
35		**TOTAL SALES FOR RESALE**	0	0	0			0
36	449	**Other Sales Revenue**		128,376	128,376	Dist Plt	44.3024%	56,874
37	449.1	**Prov for Rate Refund Riders** **	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted] **
38								
39		**TOTAL ELECTRIC OPERATING REVENUE**	1,875,647,402	(45,341,844)	1,830,305,558			763,181,408
40		**POWER PRODUCTION EXPENSES**						
41		**STEAM POWER GENERATION**						
42		**STEAM POWER OPERATION**						
43	500 000	Prod Steam Operation- Suprv & Engineering	8,140,216	(27,419)	8,112,797	D1	47.0659%	3,818,361
44	500 000	Steam Prod Oper-lat 1 & 2 -100% MO	393,388	0	393,388	100% MO	0 0000%	0
45	500 000	Steam Prod Oper-lat 2 -100% KS	(144,493)	0	(144,493)	100% KS	100 0000%	(144,493)
46	501 000	Fuel Expense						
47		Labor	8,478,502	181,279	8,659,781	E1	43.5895%	3,774,755
48		Fuel Handling - Non-labor	4 125 041	0	4 125 041	E1	43.5895%	1 798 085
49		Fuel Expense-Coal & Freight	198,089,643	0	198,089,643	E1	43.5895%	86,346,285
50		100% MO STB- (Surface Trsp Board)	(101,759)	0	(101,759)	100% MO	0 0000%	0
51		100%-KS-STB- (Surface Trsp Board)	0	0	0	100% KS	100 0000%	0
52		Fuel Expense-Oil	3,165,360	0	3,165,360	E1	43.5895%	1,379,765
53		Fuel Expense- Gas	2,008,091	0	2,008,091	E1	43.5895%	875,317
54		Fuel Expense-Residual	1,497,246	0	1,497,246	E1	43.5895%	652,642
55		Additives, incl Ammonia, Limestone & Oth	5,957,547	0	5,957,547	E1	43.5895%	2,596,865
56		Fuel Expense - Unit Train Depreciation	592,500	2,385,062	2,977,562	D1	47.0659%	1,401,416
57	502 000	Steam Operating Expense	15,840,475	212,131	16,052,606	D1	47.0659%	7,555,303
58	502 000	Steam Operating Expense-lat 2-100% MO	0	0	0	100% MO	0 0000%	0
59	502 000	Steam Operating Expense-lat 2-100% KS	0	0	0	100% KS	100 0000%	0
60	505 000	Steam Operating Electric Expense	6,718,074	111,008	6,829,082	D1	47.0659%	3,214,169
61	505 000	Steam Operating Elec Exp-lat 2-100% MO	0	0	0	100% MO	0 0000%	0
62	505 000	Steam Operating Elec Exp-lat 2-100% KS	0	0	0	100% KS	100 0000%	0
63	506 000	Miscl Other Power Expenses	10,568,055	(339,846)	10,228,209	D1	47.0659%	4,813,999
64	506 000	Miscl Other Power Exp-lat 2-100% MO	471,848	0	471,848	100% MO	0 0000%	0
65	506 000	Miscl Other Power Exp-lat 2-100% KS	548,080	0	548,080	100% KS	100 0000%	548,080
66	507 000	Steam Operating Exp - Rents	288,392	0	288,392	D1	47.0659%	135,734
67	507 000	Steam Operating Exp-Rents-lat 2-100% MO	0	0	0	100% MO	0 0000%	0
68	507 000	Steam Operating Exp-Rents-lat 2-100% KS	0	0	0	100% KS	100 0000%	0
69	509 000	Allowances						
70		KS REC's	0	0	0	100% KS	100 0000%	0
71		NOX/Other Allowances-Allocated	1,282	0	1,282	E1	43.5895%	559
72		Amort of SO2 Allowances-MO	(2,302,166)	0	(2,302,166)	100% MO	0 0000%	0
73		Amort of SO2 Allowances-KS	(1,681,238)	0	(1,681,238)	100% KS	100 0000%	(1,681,238)

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12 Month Revenues and O & M Expenses - Schedule 9

Line No.	Account No.	Description	Per Books Test Year	Rate Case Adj	Adjusted Balance	Juris Factor #	Juris Allocator	Electric Juris Adjusted Balance
74		**TOTAL STEAM OPERATION**	262,654,084	2 522 215	265 176 299			117 085 604
75		**STEAM POWER OPERATION**						
76	510 000	Steam Maintenance Suprv & Engineering	7,102,017	102,213	7,204,230	D1	47.0659%	3,390,736
	510 000	Steam Mtce Suprv & Eng-lat 2-100% MO	0	0	0	100% MO	0 0000%	0
77	510 000	Steam Mtce Suprv & Eng-lat 2-100% KS	0	0	0	100% KS	100 0000%	0
78	511 000	Maintenance of Structures	7,404,691	31,264	7,435,955	D1	47.0659%	3,499,799
	511 000	Maintenance of Structures-lat 2-100% MO	0	0	0	100% MO	0 0000%	0
79	511 000	Maintenance of Structures-lat 2-100% KS	0	0	0	100% KS	100 0000%	0
80	512 000	Maintenance of Boiler Plant		0				
81		Non-Labor	25,101,798	0	25,101,798	D1	47.0659%	11,814,387
82		Labor	9 189 841	196 526	9 386 367	D1	47.0659%	4 417 778
83		Steam Prod Mtce- lat 1 & 2-100% MO	292,105	0	292,105	100% MO	0 0000%	0
84		Steam Prod Mtce-lat 2-100% KS	0	0	0	100% KS	100 0000%	0
85	513 000	Maintenance of Electric Plant	4,308,996	31,228	4,340,224	D1	47.0659%	2,042,765
	513 000	Maintenance of Elec Plant-lat 2-100% MO	154,078	0	154,078	100% MO	0 0000%	0
86	513 000	Maintenance of Elec Plant-lat 2-100% KS	0	0	0	100% KS	100 0000%	0
87	514 000	Maintenance of Miscellaneous Steam Plant	350,019	620	350,639	D1	47.0659%	165,031
	514 000	Mtce of Misc Steam Plant-lat 2-100% MO	0	0	0	100% MO	0 0000%	0
88	514 000	Mtce of Misc Steam Plant-lat 2-100% KS	0	0	0	100% KS	100 0000%	0
89		**TOTAL STEAM MAINTENANCE**	53,903,545	361,851	54,265,396			25,330,497
90		**TOTAL STEAM POWER GENERATION EXPENSE**	316,557,629	2,884,066	319,441,695			142,416,101
91		**NUCLEAR POWER GENERATION**						
92		**NUCLEAR OPERATION**						
93	517 000	Prod Nuclear Operation- Superv & Engineer	7,590,908	138,784	7,729,692	D1	47.0659%	3,638,049
94	518 000	Nuclear Fuel Expense						
95		Nuclear Fuel - Net Amortizarion	30,725,326	0	30,725,326	E1	43.5895%	13,393,016
96		Prod Nuclear-Disposal Costs		0	0	E1	43.5895%	0
97		KS DOE Refund (100% KS)	0	0	0	E1	43.5895%	0
98		Cost of Oil	142,648	0	142,648	E1	43.5895%	62,180
99		Labor	0	0		E1	43.5895%	0
100	519 000	Coolants and Water	2,903,445	818,415	3,721,860	D1	47.0659%	1,751,727
101	520 000	Steam Expense	13,854,436	225,013	14,079,449	D1	47.0659%	6,626,619
102	523 000	Electric Expense	1,408,063	30,992	1,439,055	D1	47.0659%	677,304
103	524 000	Miscellaneous Nuclear Power Exp						
104		Misc. Nuclear Power Exp-100% KS	0	0	0	100% KS	100 0000%	0
105		Decommissioning-Missouri	1,281,264	0	1,281,264	100% MO	0 0000%	0
106		Decommissioning-Kansas	2,036,230	0	2,036,230	100% KS	100 0000%	2,036,230
107		Decommissioning-FERC	38,753	0	38,753	NonJur/Wh	0 0000%	0
108		Refueling Outage Amortization	184,776	121,978	306,754	D1	47.0659%	144,377
109		Refueling Outage Amortization - MO only	250,859	(201,816)	49,043	100% MO	0 0000%	0
110		Misc. Nucl Power Exp-Other-Alloc	22,870,983	194,818	23,065,801	D1	47.0659%	10,856,127
111	525 000	Rents	0	0	0	D1	47.0659%	0
112		**TOTAL NUCLEAR OPERATION**	83,287,691	1,328,184	84,615,875			39,185,628
113		**NUCLEAR MAINTENANCE**						
114	528 000	Prod Nuclear Maint- Suprv & Engineer	5,100,696	57,242	5,157,938	D1	47.0659%	2,427,630
115	529 000	Prod Nuclear Maint- Maint of Structures	2,420,831	44,078	2,464,909	D1	47.0659%	1,160,132
116	530 000	Prod Nuclear Maint- Maint Reactor Plant						
117		Refueling Outage Amortization	1,361,937	256,292	1,618,229	D1	47.0659%	761,634
118		Refueling Outage Amortization - MO only	1,049,271	(605,449)	443,822	100% MO	0 0000%	0
119		Maint Reactor Plant - Other	9,168,318	13,114	9,181,432	D1	47.0659%	4,321,324
120	531 000	Prod Nuclear Mtce - Electric Plant	4 019 234	37 558	4 056 792	D1	47.0659%	1 909 366
121	532 000	Prod Nuclear Maint- Maint of Miscl Plant	2,740,805	26,262	2,767,067	D1	47.0659%	1,302,345
122		**TOTAL NUCLEAR MAINTENANCE**	25,861,092	(170,903)	25,690,189			11,882,430
123		**TOTAL NUCLEAR POWER GENERATION**	109,148,783	1,157,281	110,306,064			51,068,058
124		**OTHER POWER GENERATION**						
125		**OTHER POWER OPERATION**						
126	546 000	Prod Turbine Oper-Supr & Engineering	116,079	(4,423)	111,656	D1	47.0659%	52,552
127	547 000	Other PowerOperation- Fuel Expense						
128		Labor	55,066	1,178	56,244	E1	43.5895%	24,516
129		Fuel Handling (non-labor)	62,930	0	62,930	E1	43.5895%	27,431
130		Other Fuel Expense - Oil	526,759	0	526,759	E1	43.5895%	229,612
131		Other Fuel Expense - Gas	6,279,967	0	6,279,967	E1	43.5895%	2,737,406
132		Other Fuel Expense - Hedging - MO	13,790	0	13,790	100% MO	0 0000%	0
133		Additives	20,929	0	20,929	E1	43.5895%	9,123
134	548 000	Other Power Generation Expense	902,476	14,370	916,846	D1	47.0659%	431,522
135	549 000	Misc Other Power Generation Expense	1,298,562	7,884	1,306,446	D1	47.0659%	614,891
136	550 000	Other Generation Rents	0	0	0	D1	47.0659%	0
137		**TOTAL OPERATION - OP**	9,276,558	19,009	9,295,567			4,127,052

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138		**OTHER POWER MAINTANENCE**						
139	551 000	Other Maint-Supr Eng. Struct Gen & Misc.	37,866	783	38,649	D1	47.0659%	18,190
140	552 000	Other General Maintenance of Structures	167,873	538	168,411	D1	47.0659%	79,264
141	553 000	Other General Maint of General Plant	2,299,364	26,857	2,326,221	D1	47.0659%	1,094,857
142	554 000	Other Gen Maint Miscl. Other General Plant	33 312	151	33 463	D1	47.0659%	15 750
143		**TOTAL MAINTANENCE - OP**	2,538,415	28,329	2,566,744			1,208,061
144		**TOTAL OTHER POWER GENERATION**	11,814,973	47,338	11,862,311			5,335,113
145		**OTHER POWER SUPPLY EXPENSES**						
146	555 000	Purchased Power						
147		Purchased Power-Energy	144 601 307	0	144 601 307	E1	43.5895%	63 030 987
148		Purchased Power-Capacity (Demand)	0	0	0	E1	43.5895%	0
149		Purch Pwr Energy Solar Contrct (100% MO)	0	0	0	100% MO	0 0000%	0
150		Solar Renew Energy Credits (100% MO)	0	0	0	100% MO	0 0000%	0
151	556 000	System Control and Load Dispatch	1,838,487	33,228	1,871,715	D1	47.0659%	880,940
152	557 000	Other Expenses	8,320,817	(305,524)	8,015,293	D1	47.0659%	3,772,470
153	557.100	373ECATRUE 11200	(2,465,719)	2,465,719	0	100% KS	100 0000%	0
154	557.100	373KCPFAC 10200	(11,373,112)	0	(11,373,112)	100% MO	0 0000%	0
155		**TOTAL OTHER POWER SUPPLY EXPENSES**	140,921,780	2,193,423	143,115,203			67,684,396
156		**TOTAL POWER PRODUCTION EXPENSES**	578,443,165	6,282,108	584,725,273			266,503,668
157		**TRANSMISSION EXPENSES**						
158		**OPERATION - TRANSMISSION EXP.**						
159	560 000	Transmission Operation Suprv and Engrg	824,635	(688,667)	135,968	D1	47.0659%	63,995
160	561 000	561.4 & 561.8 Transmission Operation- Load Dispatch	7,053,685	(5,054,885)	1,998,800	E1	43.5895%	871,267
161	561 000	Other 561 Transmission Operation- Load Dispatch	0	15,351	15,351	E1	43.5895%	6,691
161	562 000	Transmission Operation- Station Expenses	741,821	(610,098)	131,723	D1	47.0659%	61,997
162	563 000	Transmission Operation-Overhead Line Expense	312,482	(257,803)	54,679	D1	47.0659%	25,735
163	564 000	Trans Oper-Underground Line Expense	13,000	0	13,000	D1	47.0659%	6,119
164	565 000	Transmission of Electricity by Others	64,874,976	(45,957,916)	18,917,060	E1	43.5895%	8,245,852
165	565.100	Trans Op Trans Rider all KS 11200	(391,252)	391,252	0	100% KS	100 0000%	0
166	566 000	Miscl. Transmission Expense	2,920,641	(2,405,139)	515,502	D1	47.0659%	242,626
167	567 000	Transmission Operation Rents	2,423,612	(2,423,612)	0	D1	47.0659%	0
168	575 000	Regional Transmission Operation	6 646 953	(5 370 156)	1 276 797	E1	43.5895%	556 549
169		**TOTAL OPERATION - TRANSMISSION EXP.**	85,420,553	(62,361,673)	23,058,880			10,080,830
170		**MAINTENANCE - TRANSMISSION EXP.**						
171	568 000	Transmission Maint-Suprv and Engrg	(80,246)	66,064	(14,182)	D1	47.0659%	(6,675)
172	569 000	Transmission Maintenance of Structures	0	0	0	D1	47.0659%	0
173	570 000	Transmission Maintenance of Station Equipment	644,576	(530,173)	114,403	D1	47.0659%	53,845
174	571 000	Transmission Maintenance of Overhead Lines	2,335,190	(1,926,562)	408,628	D1	47.0659%	192,324
175	572 000	Trans Maintenance of Underground Lines	5,624	(4,640)	984	D1	47.0659%	463
176	573 000	Trans Maintenance of Miscl. Trans Plant	5,821	(4,802)	1,019	D1	47.0659%	480
177	576 000	Transmission Maintenance-Comp	0	0	0	D1	47.0659%	0
178		**TOTAL MAINTENANCE - TRANSMISSION EXP.**	2,910,965	(2,400,113)	510,852			240,437
179		**TOTAL TRANSMISSION EXPENSES**	88,331,518	(64,761,786)	23,569,732			10,321,267
180		**DISTRIBUTION EXPENSES**						
181		**OPERATION - DIST. EXPENSES**						
182	580 000	Distribution Operation - Supr & Engineering	3,461,005	(244,736)	3,216,269	Dist Plt	44.3024%	1,424,883
183	581 000	Distribution Operation - Load Dispatching	492 771	10 332	503 103	Dist Plt	44.3024%	222 887
184	582 000	Distribution Operation - Station Expense	139,089	1,386	140,475	362	37.8780%	53,209
185	583 000	Dist Operation Overhead Line Expense	2,249,576	34,006	2,283,582	365	43.3827%	990,680
186	584 000	Dist Operation Underground Line Expense	4,033,947	18,831	4,052,778	367	47.2175%	1,913,620
187	585 000	Distrb Oper Street Light & Signal Expense	49	0	49	373	52.6596%	26
188	586 000	Distribution Operation Meter Expense	2,629,165	51,242	2,680,407	370	47.8273%	1,281,966
189	587 000	Distrb Operation Customer Install Expense	137,140	2,807	139,947	371	31.4016%	43,946
190	588 000	Dist Operation Miscl Distribution Expense	13,937,944	122,055	14,059,999	Dist Plt	44.3024%	6,228,913
191	589 000	Distribution Operations Rents	79 453	245	79 698	Dist Plt	44.3024%	35 308
192		**TOTAL OPERATION - DIST. EXPENSES**	27,160,139	(3,832)	27,156,307			12,195,438
193		**MAINTENANCE - DISTRIB. EXPENSES**						
194	590 000	Distribution Maint-Suprv & Engineering	91,832	1,862	93,694	Dist Plt	44.3024%	41,509
195	591 000	Distribution Maintenance-Structures	681	7	688	361	43.2654%	298
196	592 000	Distribution Maintenance-Station Equipment	877,453	13,841	891,294	362	37.8780%	337,604
197	593 000	Distribution Maintenance-Overhead lines	21,475,027	144,430	21,619,457	365	43.3827%	9,379,104
198	593 000	Distribution Maint. Overhead lines- 100% MO	0	0	0	100% MO	0 0000%	0
199	593 000	Dist. Maint Overhead Lines Veg Mgmt 100% MO	0	0	0	100% MO	0 0000%	0
200	594 000	Distrib Maint-Maintenance Underground Lines	1,957,087	31,123	1,988,210	367	47.2175%	938,783
201	594 000	Dist Maint. Underground Lines 100% MO	0	0	0	100% MO	0 0000%	0
202	595 000	Distrib Maint-Maintenance Line Transformer	325,895	5,616	331,511	368	43.2615%	143,417
203	596 000	Distrib Maint- Maintenance St Lights/Signal	672,414	5,327	677,741	373	52.6596%	356,896
204	597 000	Distrib Maint-Maintenance of Meters	188,552	1,061	189,613	370	47.8273%	90,687
205	598 000	Distrib Maint-Maint Miscl Distribution Plant	2 098 872	115 135	2 214 007	Dist Plt	44.3024%	980 858
206		**TOTAL MAINTENANCE - DISTRIB. EXPENSES**	27,687,813	318,402	28,006,215			12,269,155
207		**TOTAL DISTRIBUTION EXPENSES**	54,847,952	314,570	55,162,522			24,464,592

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12 Month Revenues and O & M Expenses - Schedule 9

Line No.	Account No.	Description	Per Books Test Year	Rate Case Adj	Adjusted Balance	Juris Factor #	Juris Allocator	Electric Juris Adjusted Balance
208		**CUSTOMER ACCOUNTS EXPENSE**						
209	901 000	Cust Acct-Suprv Meter Read Collection Miscl	304,595	10,787	315,382	C1	47.3951%	149,476
210	902 000	Cust Accts Meter Reading Expense	4,653,849	614,072	5,267,921	C1	47.3951%	2,496,736
211	903 000	Customer Accts Records and Collection	13,933,048	261,555	14,194,603	C1	47.3951%	6,727,546
212	903 000	Cust Accts-Interest on Deposits - MO	0	196,733	196,733	100% MO	0 0000%	0
213	903 000	Cust Accts-Interest on Deposits - KS	0	29,306	29,306	100% KS	100 0000%	29,306
214	904 000	Uncollectible Accounts-MO 100%	0	5,462,528	5,462,528	100% MO	0 0000%	0
215	904 000	Uncollectible Accts-KS 100%	0	2,282,284	2,282,284	100% KS	100 0000%	2,282,284
216	905 000	Miscellaneous Customer Accts Expense	765 547	2 926 515	3 692 062	C1	47.3951%	1 749 856
217		**TOTAL CUSTOMER ACCOUNTS EXPENSE**	**19,657,039**	**11,783,780**	**31,440,819**			**13,435,205**
218		**CUSTOMER SERVICE & INFO EXP**						
219	907 000	Customer Service Suprv	94,797	2,027	96,824	C1	47.3951%	45,890
220	908 000	Customer Assistance Expense						
221		Customer Assistance Exp-100% KS	(373)	173,685	173,312	100% KS	100 0000%	173,312
222		Customer Assistance Exp-100% MO	10,195,426	0	10,195,426	100% MO	0 0000%	0
223		Customer Assistance Expense-Allocated	(415,815)	17,133	(398,682)	C1	47.3951%	(188,956)
224	908.100	Cust Assist Exp - Exp Rider 343 MEIAA4 100% MO	2,780,110	0	2,780,110	100% MO	0 0000%	0
225	908 500	Cust Assist Exp - MEEIA 100% MO	25,322,195	0	25,322,195	100% MO	0 0000%	0
226	908 500	Cust Assist Exp - KEEIA 100% KS	63,867	0	63,867	100% KS	100 0000%	63,867
227	909 000	Information and Instruction Advertising						
228		Information and Instruction Advertising	133,961	(600)	133,361	C1	47.3951%	63,207
229		Inform & Instructional Advertis- 100% MO	50,986	0	50,986	100% MO	0 0000%	0
230	910 000	Misc Customer Accounts and Info Exp						
231		Misc Cust Accts & Info Exp-Allocated	1,169,455	321,201	1,490,656	C1	47.3951%	706,498
232		Misc Cust Accts & Info Exp-100% MO	7,753,859	0	7,753,859	100% MO	0 0000%	0
233		**TOTAL CUSTOMER SERVICE & INFO EXP**	**47,148,468**	**513,446**	**47,661,914**			**863,818**
234		**SALES EXPENSES**						
235	911 000	Sales Supervision	0	0	0	C1	47.3951%	0
236	912 000	Sales Demonstration and Selling	528,411	(1,211)	527,200	C1	47.3951%	249,867
237	913 000	Sales Advertising Expense	0	0	0	C1	47.3951%	0
238	916 000	Miscellaneous Sales Expense	0	0	0	C1	47.3951%	0
239		**TOTAL SALES EXPENSES**	**528,411**	**(1,211)**	**527,200**			**249,867**
240		**ADMIN. & GENERAL EXPENSES**						
241		**OPERATION - ADMIN. & GENERAL EXP**						
242	920 000	Admin & Gen-Administrative Salaries						
243		Admin & Gen-Admin Salaries - Allocated	38,692,228	(4,470,594)	34,221,634	Sal&Wg	46.4069%	15,881,214
244		Admin & Gen-Admin. Salaries- 100% MO	(28,240)	0	(28,240)	100% MO	0 0000%	0
245		Admin & Gen- Admin. Salaries- 100% KS	1,220,486	(1,220,486)	0	100% KS	100 0000%	0
246	921 000	Admin & General Off Supply						
247		Admin & General Off Supply- Allocated	(993,178)	5,786	(987,392)	E1	43.5895%	(430,399)
248		Admin & General Off Supply- 100% MO	(14,653)	0	(14,653)	100% MO	0 0000%	0
249		Admin & General Off Supply- 100% KS	448	(11,118)	(10,670)	100% KS	100 0000%	(10,670)
250		Settlement - Misc Issues for ER-xxxx-xxxx	0	0	0	E1	43.5895%	0
251	922 000	Admin Expense Transfer Credit	(15,373,708)	(6,985,142)	(22,358,850)	E1	43.5895%	(9,746,111)
252	922 001	Admin Expense Transfer Credit 2	0	0	0	E1	43.5895%	0
253	923 000	Outside Services Employed						
254		Outside Services Employed-Allocated	13,832,966	1,847,413	15,680,379	E1	43.5895%	6,834,999
255		Outside Services-100 % MO	(17,387)	0	(17,387)	100% MO	0 0000%	0
256		Outside Services- 100% KS	84,280	1,260,555	1,344,835	100% KS	100 0000%	1,344,835
257	924 000	Property Insurance	4,056,361	25,871	4,082,232	PTD	46.2712%	1,888,898
258	925 000	Injuries and Damages	18,415,953	(11,082,275)	7,333,678	Sal&Wg	46.4069%	3,403,336
259	926 000	Employee Pensions and Benefits						
260		Employee Pensions	50,909,432	(3,172,643)	47,736,789	Sal&Wg	46.4069%	22,153,184
261		Employee OPEB	3,115,279	(2,607,019)	508,260	Sal&Wg	46.4069%	235,868
262		Empl Ben-OPEB-MO	(385,309)	0	(385,309)	100% MO	0 0000%	0
263		Empl Ben-OPEB-KS	(545,034)	10,850	(534,184)	100% KS	100 0000%	(534,184)
264		Other Miscellaneous Employee Benefits	31,059,075	66,421	31,125,496	Sal&Wg	46.4069%	14,444,391
265	927 000	Franchise Requirements	0	0	0	C1	47.3951%	0
266	928 000	Regulatory Comm Exp						
267		Regulatory Comm Exp-FERC Assment	918,283	(841,180)	77,103	E1	43.5895%	33,609
268		Reg Comm Exp- KCC Assmnt - 100% KS	1,329,309	(80,954)	1,248,355	100% KS	100 0000%	1,248,355
269		Reg Comm Exp- MPSC Assmnt - 100% MO	1,757,640	257,169	2,014,809	100% MO	0 0000%	0
270		Reg Comm Exp- MO Proceeding 100% MO	1,109,496	15,457	1,124,953	100% MO	0 0000%	0
271		Reg Comm Exp- KS Proceeding 100% KS	677,512	133,593	811,105	100% KS	100 0000%	811,105
272		Reg Comm Exp- FERC Proceed - Allocated	0	0	0	E1	43.5895%	0
273		Regulatory Comm Expense- FERC Proceedings 100% FER(	0	0	0	NonJur/Wh	0 0000%	0
274		Load Research Expenses- 100% MO	0	0	0	100% MO	0 0000%	0
275		Miscellaneous Regulatory Expense	1,697,337	(33,777)	1,663,560	D1	47.0659%	782,969
276	929 000	Duplicate Charges-Credit	0	0	0	PTD	46.2712%	0
277	930.100	General Advertising Expense						
278		General Advertising Expense - Allocated	35 660	(35 660)	0	C1	47.3951%	0
279		General Advertising Expense - 100% MO	0	0	0	100% MO	0 0000%	0
280	930 200	Miscellaneous General Expense	6,298,107	(578,032)	5,720,075	E1	43.5895%	2,493,352
281	931 000	Admin & General Expense-Rents-Allocated	3,223,125	(64,162)	3,158,963	E1	43.5895%	1,376,976
282		Admin & General Expense-Rents-100% MO	(200,220)	0	(200,220)	100% MO	0 0000%	0
283		Admin & General Expense-Rents-100% KS	0	0	0	100% KS	100 0000%	0
284	933 000	Transportation Expense	0	(418 743)	(418 743)	Dist Plt	44.3024%	(185 513)
285		**TOTAL OPERATION- ADMIN. & GENERAL EXP**	**160,875,248**	**(27,978,670)**	**132,896,578**			**62,026,213**

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12 Month Revenues and O & M Expenses - Schedule 9

Line No.	Account No.	Description	Per Books Test Year	Rate Case Adj	Adjusted Balance	Juris Factor #	Juris Allocator	Electric Juris Adjusted Balance
286		**MAINT, ADMIN. & GENERAL EXP**						
287	935 000	Maintenance Of General Plant	8 582 591	1 782 570	10 365 161	PTD	46.2712%	4 796 085
288		TOTAL MAINT, ADM N. & GENERAL EXP	8 582 591	1 782 570	10 365 161			4 796 085
289		**TOTAL ADMIN. & GENERAL EXPENSES**	**169,457,839**	**(26,196,100)**	**143,261,739**			**66,822,298**
290		**TOTAL ELEC OPER & MAINT EXP**	**958,414,392**	**(72,065,194)**	**886,349,198**			**382,660,716**
291		**DEPRECIATION EXPENSE**					Blended	
292	403 000	Depreciation Expense, Dep. Exp.	241,455,312	39,384,594	280,839,906		46.4463%	130,439,716
293	403 001	Other Depreciation		0	0			
294		**TOTAL DEPRECIATION EXPENSE**	**241,455,312**	**39,384,594**	**280,839,906**			**130,439,716**
295		**AMORTIZATION EXPENSE**						
296	404 000	Amortization of Limited Term Plant-Allocated	1,908,936	(35,229)	1,873,707	PTD	46.2712%	866,987
297	405 001	Amort-Iatan Reg Asset & Oth Non-Plant - MO	1,126,101	0	1,126,101	100% MO	0 0000%	0
298	405 001	Amort-Iatan, LC & WC Reg Asset/Liab - KS	(153,711)	(1,040,440)	(1,194,151)	100% KS	100 0000%	(1,194,151)
299	405 010	Amortization-Other Plant-Allocated	32,677,180	8,863,226	41,540,406	PTD	46.2712%	19,221,246
300	405 010	Amortiz of Unrecovered Reserve-KS	1,661,925	0	1,661,925	100% KS	100 0000%	1,661,925
301	405 010	Amortiz of Unrecov Dist Meters-KS	1,115,338	0	1,115,338	100% KS	100 0000%	1,115,338
302	407 300	Regulatory Debits	940,556	0	940,556	NonJur/Wh	0 0000%	0
303	407.400	Regulatory Credits	(30,300,963)	0	(30,300,963)	NonJur/Wh	0 0000%	0
304	407.400	Regulatory Credits - Migration Amortiz	31,854	95,563	127,417	100% KS	100 0000%	127,417
305	411.100	Accretion Exp-Asset Retirement Obligation	13,374,942	0	13,374,942	NonJur/Wh	0 0000%	0
306	411 000	Write down-Emissions Allowance Liab-Whsl	0	0	0	NonJur/Wh	0 0000%	0
307		**TOTAL AMORTIZATION EXPENSE**	**22,382,158**	**7,883,119**	**30,265,277**			**21,798,762**
308		**OTHER OPERATING EXPENSES**						
309		Taxes Other Than Income Taxes-Allocated						
310	408.100	KS Property Tax RIDER	(2,025,122)	2,025,122	0	100% KS	100 0000%	0
311	408.103	Other Miscellaneous Taxes	2,808	0	2,808	PTD	46.2712%	1,299
312	408.110	KCMO City Earnings Tax-100% MO	592,700	0	592,700	100% MO	0 0000%	0
313	408.120	Property Tax	79,415,857	1,448,301	80,864,158	Elec Plt wo WC	46.1235%	37,297,346
314	408.121	Property Tax - Wolf Creek	20,434,436	(757,066)	19,677,370	WC Plt	47.0659%	9,261,331
315	408.130	Gross Receipts Tax-100% MO	70,188,095	0	70,188,095	100% MO	0 0000%	0
316	408.140	Payroll Tax, incl Unemployment	12,165,441	489,200	12,654,641	Sal&Wg	46.4069%	5,872,632
317	408.140	ORVIS - KS	41 152	(41 152)	(0)	100% KS	100 0000%	(0)
318		**TOTAL OTHER OPERATING EXPENSES**	**180,815,367**	**3,164,405**	**183,979,772**			**52,432,608**
319		**TOTAL OPERATING EXPENSE**	**1,403,067,229**	**(21,633,076)**	**1,381,434,153**			**587,331,802**
320		**NET INCOME BEFORE TAXES**	**472,580,173**	**(23,708,768)**	**448,871,405**			**175,849,606**
321	409.100	**INCOME TAXES**						
322		Current Income Taxes	69 211 672	15 103 075	84 314 747	Sch11		31 705 059
323		**TOTAL CURRENT INCOME TAXES**	**69,211,672**	**15,103,075**	**84,314,747**			**31,705,059**
324	410 & 411	**DEFERRED INCOME TAXES**						
325		Deferred Income Taxes - Def. Inc. Tax.	52,303,590	(55,528,294)	(3,224,704)	Sch 11		(1,961,053)
326		Amortization of Deferred ITC	(962,914)	(124,738)	(1,087,652)	Sch 11		(503,270)
327		Amort of Excess Deferred Income Taxes		(2,478,027)	(2,478,027)	Sch 11		(1,146,613)
328		Amort of Cost of Removal-ER-2007-0291	0	354 438	354 438	Sch 11		0
329		**TOTAL DEFERRED INCOME TAXES**	**51,340,676**	**(57,776,621)**	**(6,435,945)**			**(3,610,936)**
330								
331		**TOTAL INCOME TAXES**	**120,552,348**	**(42,673,546)**	**77,878,802**			**28,094,123**
332								
333		**NET OPERATING INCOME**	**352,027,825**	**18,964,778**	**370,992,603**			**147,755,483**

	Per Books Test Year	Rate Case Adj	Adjusted Balance	Electric Juris Adjusted Balance
Summary of Fuel & Purchased Power Expense				
Acct 501 - Steam Prod	223,812,171	2,566,341	226,378,512	98,825,130
Acct 509 - Allowances	(3,982,122)	0	(3,982,122)	(1,680,679)
Acct 518 - Nuclear Fuel	30,867,974	0	30,867,974	13,455,196
Acct 547 - CT's and Other Prod	6,959,441	1,178	6,960,619	3,028,088
Total Fuel	257,657,464	2,567,519	260,224,983	113,627,734
Acct 555 - Purchased Power	144,601,307	0	144,601,307	63,030,987
Total Fuel & Purchased Power	402,258,771	2,567,519	404,826,290	176,658,721

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Summary of Adjustments

Line No.	Adj No.	Description	Witness	Increase (Decrease)			
	A	B		D	E	F	G
				Adjust to 6-30-18 - Update Date			
				Total Adjustments	Allocated Adjs	100% MO & Whsl Adjs (2)	100% KS Adjs
				Incr (Decr)	Incr (Decr)	Incr (Decr)	Incr (Decr)
1	**JURISDICTIONAL COST OF SERVICE**						
2	**OPERATING REVENUE**						
3	R-20	Normalize KS Retail revenues (KS only)	Bass / Miller / Nunn	(29,481,934)			(29,481,934)
4	R-21a	Adjust KS forfeited discounts LPC for R-20 (KS Only)	Nunn	25,213			25,213
5	R-21b	Adjust KS forfeited discounts LPC - ASK (KS only)	Nunn	71,304			71,304
6	R-49	CNN Revenue	Nunn	128,376	128,376		
7	R-82	Transmission Delivery Charge Adjustment	Klote	(16,084,803)	(16,084,803)		
8				(45,341,844)	(15,956,427)	0	(29,385,417)
9	**OPERATING EXPENSES**						
10	CS-4	Reflect KCREC test year bad debt expense in KCP&L's COS	Nunn	7,463,092		5,462,528	2,000,564
11	CS-9	Reflect KCREC test year bank commitment fees in KCP&L's COS	Nunn	1,981,200	1,981,200		
12	CS-10	Reflect test year interest on customer deposits in COS	Nunn	192,124		179,346	12,778
13	CS-11	Reverse prior period and non-recurring test year amounts.	Nunn	(4,107,664)	(4,107,664)		
14	CS-20a	Normalize bad debt expense related to test year revenue	Nunn	184,170			184,170
15	CS-20b	Normalize bad debt expense related to jurisdictional "Ask" (KS only)	Nunn	97,550			97,550
16	CS-23	Remove ECA Under Collection	Nunn	2,856,971			2,856,971
17	CS-26	ECA costs	n/a	0	0		
18	CS-27	Wolf Creek Water Contract	Klote	771,494	771,494		
19	CS-35	Eliminate Wolf Creek Mid-Cycle Outage	Klote	0	0		
20	CS-36	Annualize Wolf Creek refueling outage amortization	Klote	(428,995)	378,270	(807,265)	
21	CS-37	Adjust Nuclear decommissioning expense	Klote	0			
22	CS-39	IT Software Maintenance	Klote	610,529	610,529		
23	CS-40	Transmission Maintenance	Nunn	0	0		
24	CS-41	Distribution Maintenance	Nunn	0	0		
25	CS-42	Generation Maintenance	Nunn	0	0		
26	CS-43	Wolf Creek Maintenance	Nunn	0	0		
27	CS-49	Miscellaneous O&M	Nunn	359,992	359,992		
28	CS-50	Annualize salary and wage expense for changes in staffing levels and base pay rates	Klote	3,496,847	3,467,493	15,457	13,897
29	CS-51	Normalize incentive compensation costs	Klote	(1,693,078)	(1,693,078)		
30	CS-52	Normalize 401(k) costs	Klote	(151,259)	(151,259)		
31	CS-55	Severance / ORVS	Nunn	(843,995)			(843,995)
32	CS-60	Annualize other benefit costs	Klote	154,768	154,768		
33	CS-61	Annualize OPEB expense	Klote	(2,596,696)	(2,596,696)		
34	CS-65	Annualize Pension expense (includes SERP)	Klote	(2,203,060)	(2,203,060)		
35	CS-70	Annualize Insurance premiums	Klote	387,223	387,223		
36	CS-71	Normalize injuries and damages expense	Nunn	(11,211,892)	(11,211,892)		
37	CS-76	Annualize interest on customer deposits	Nunn	33,915		17,387	16,528
38	CS-77	Annualize Customer Accounts expense for credit card payment costs	Nunn	138,472	138,472		
39	CS-78	Annualize KCREC bank fees related to sale of receivables	Nunn	938,234	938,234		
40	CS-80	Amortize KS Rate Case expenses	Nunn	119,696			119,696
41	CS-82	Transmission Delivery Charge Adjustment	Klote	(70,050,803)	(70,034,555)	0	(16,248)
42	CS-85	Annualize regulatory assessments	Nunn	253,315	77,100	257,169	(80,954)
43	CS-88	CIPS/Cyber Security O&M	Nunn	3,671,539	3,671,539		
44	CS-89	Meter Replacement O&M	Nunn	598,073	598,073		
45	CS-90	Advertising	Nunn	(36,260)	(36,260)		
46	CS-92	Adjust dues, donations and contributions	Nunn	38,390	38,390		
47	CS-95	Merger Effects	Klote	1,372,150			1,372,150

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Summary of Adjustments

Line No.	Adj No.	Description	Witness	Increase (Decrease)			
	A	B		D	E	F	G
				Adjust to 6-30-18 - Update Date			
				Total Adjustments	Allocated Adjs	100% MO & Whsl Adjs (2)	100% KS Adjs
				Incr (Decr)	Incr (Decr)	Incr (Decr)	Incr (Decr)
48	CS-96	Amortize Merger transition costs (KS only)	Nunn	(111,111)			(111,111)
49	CS-99	Flood Reimbursement Amortization	Nunn	155,380	155,380		
50	CS-101	Amortize Talent Assessment severance and outplacement regulatory asset	Nunn	(411,640)			(411,640)
51	CS-102	Employee Augmentation	Nunn	(26,418)			(26,418)
52	CS-103	EE Amortization	Nunn	173,685			173,685
53	CS-107	Transource Account Review Amortization	Nunn	21,453			21,453
54	CS-110	Flood AAO Amortization	Nunn	0			0
55	CS-115	Amortize Legal fee reimbursement	Nunn	14,458			14,458
56	CS-117	Common-use Billings	Klote	(7,414,333)	(7,414,333)		
57	CS-120	Annualize depr exp based on jurisdictional depr rates applied to jurisdictional plant-in-service at indicated period - unit trains & transportation equipment	Klote	1,957,813	1,957,813		
58				(73,244,671)	(83,762,827)	5,124,622	5,393,534
59	**Depreciation Expense**						
60	CS-120	Annualize depreciation expense based on jurisdictional depreciation rates applied to jurisdictional plant-in-service at indicated period	Klote	39,384,594	39,384,594		
61				39,384,594	39,384,594	0	0
62	**Amortization Expense**						
63	CS-111	Amortization Iatan 1 & Cmn Reg Asset	Nunn	0			0
64	CS-113	Amortization of La Cygne Reg Asset - Depr Deferral	Nunn	0			0
65	CS-118	Amortize Meter Replacement Unrecovered Reserve	Nunn	0			0
66	CS-121	Annualize plant amortization expense based on jurisdictional amortization rates applied to unamortized jurisdictional plant-in-service at indicated period	Klote	9,709,293	9,709,293		
67	CS-122	Amortize General Plant Unrecovered Reserve	Klote	0			0
68	CS-130	Amortize Customer Migration	Nunn	95,563			95,563
69	CS-131	Amortize La Cygne BUD Plant Reg Liability	Nunn	(992,933)			(992,933)
70	CS-132	Amortize La Cygne BUD Deferred Depreciation	Nunn	(5,833)			(5,833)
71	CS-133	Amortize Wolf Creek BUD Plant Reg Liability	Nunn	(41,675)			(41,675)
72				8,764,415	9,709,293	0	(944,878)
73	**Taxes Other than Income**						
74	CS-53	Annualize FICA payroll tax expense	Klote	746,229	746,229		
75	CS-126	Adjust property tax expense	Klote	2,716,357	2,716,357		
76				3,462,586	3,462,586	0	0
77	**Income Tax Expense**						
78	CS-125	Reflect adjustments to Schedule 9, Allocation of Current and Deferred Income Taxes	Klote	(42,673,546)	(43,027,984)	354,438	
79				(42,673,546)	(43,027,984)	354,438	0
80		**Total Electric Oper. Expenses**		(64,306,622)	(74,234,338)	5,479,060	4,448,656
81		**Net Electric Operating Income**		18,964,778	58,277,911	(5,479,060)	(33,834,073)

(1) All amounts are total company; if an adjustment is applicable to only KS or MO it is so indicated
(2) These adjustments affect Missouri and Wholesale jurisdictions and are not discussed in testimony supporting the Missouri rate case.

SECTION 4
PLANT INVESTMENTS

Filed in Accordance with K A R 21-1-231(c)(4)(D)

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Total Plant in Service - Schedule 3

Line No.	Account No.	Description	KS Basis For Juris Books Total Co Plant	Adjustments: RB-20 Estimated Net Additions		Adjustments: Charging Stations SEPT17	Adjustments: RB-82 TDC Adj	Total Adjustments	Adjusted Plant	Juris Factor #	Juris Allocation	Electric Juris Adjusted Plant
	A	B	C	D	E	F	G	H	I	J	K	L
1	**INTANGIBLE PLANT**											
2	30100	Organization	$ 72,186				$ (1,437)	$ (1,437)	$ 70,749	PTD	46.271%	$ 32,737
3	30200	Franchises and Consents	22,937				(457)	(457)	22,480	100% MO	0.000%	-
4	30301	Miscellaneous Intangibles (Like 353)	2,033,869				(40,488)	(40,488)	1,993,381	D1	47.066%	938,203
5		Misc Intangible Plant-5-Year Software, excl Wolf Creek					-					
6	30302	Customer Related	52,490,858	19,729,430			(1,437,668)	18,291,762	70,782,620	C1	47.395%	33,547,494
7	30302	Energy Related	9,432,418	-			(187,768)	(187,768)	9,244,649	E1	43.590%	4,029,696
8	30302	Demand Related	45,696,347	-			(909,664)	(909,664)	44,786,683	D1	47.066%	21,079,255
9	30302	Corporate Software	35,886,940	-			(714,391)	(714,391)	35,172,550	Sal&Wg	46.407%	16,322,505
10	30302	Transmission Related	3,828,595	-			(76,215)	(76,215)	3,752,380	D1	47.066%	1,766,092
11		Miscl Intangible Plt - 10 yr Software		-			-					
12	30303	Customer Related	91,465,014	-			(1,820,767)	(1,820,767)	89,644,247	C1	47.395%	42,486,981
13	30303	Energy Related	38,452,423	-			(765,461)	(765,461)	37,686,962	E1	43.590%	16,427,558
14	30303	Demand Related	28,204,415	-			(561,457)	(561,457)	27,642,958	D1	47.066%	13,010,407
15	30303	Corporate Software	32,223,908	-			(641,472)	(641,472)	31,582,436	Sal&Wg	46.407%	14,656,443
16	30305	Miscl Intang Plt - WC 5yr Software	28,582,230	-			(568,978)	(568,978)	28,013,252	D1	47.066%	13,184,689
17	303XX	Miscl Intang Plt - 15yr Software		124,318,950			(2,474,780)	121,844,170	121,844,170	D1	47.066%	57,347,055
18	30307	Miscl Intg Plt-Srct (Like 312)	34,980				(696)	(696)	34,284	D1	47.066%	16,136
19	30308	Miscl Intang Trans Line (Like 355)	6,874,227				(136,843)	(136,843)	6,737,384	D1	47.066%	3,171,010
20	30309	Miscl Intang Trans Ln MINT Line	55,209				(1,099)	(1,099)	54,110	D1	47.066%	25,468
21	30310	Miscl Intang-Iatan Hwy & Bridge	3,243,743				(64,572)	(64,572)	3,179,170	D1	47.066%	1,496,305
22	30311	Misc Intan-LaCygne Road Overpass	870,852				(17,336)	(17,336)	853,516	D1	47.066%	401,715
23	30312	Misc Intan-Montrose Highway	491,275				(9,780)	(9,780)	481,496	D1	47.066%	226,620
24	30313	Misc Intan-Radio Frequencies	1,464,314				(29,150)	(29,150)	1,435,164	D1	47.066%	675,473
25		**TOTAL PLANT INTANGIBLE**	**$ 381,426,740**	**$ 144,048,380**	**$ -**	**$ -**	**$ (10,460,476)**	**$ 133,587,904**	**$ 515,014,644**			**$ 240,841,842**
26	**PRODUCTION PLANT**											
27	**STEAM PRODUCTION**											
28	31000	Sm Pr-Land	9,644,655					-	9,644,655	D1	47.066%	4,539,343
29	31100	Stm Pr-Structures-Elec	309,650,185	220,906				220,906	309,871,091	D1	47.066%	145,843,618
30	31101	Stm Pr-Struc-Lshd Impr-P&M	1,255,599	-				-	1,255,599	D1	47.066%	590,959
31	31102	Stm Pr-Struc-H5 Rebuild	8,653,542	-				-	8,653,542	D1	47.066%	4,072,867
32	31104	Stm Pr-Structure Iatan 2-Elec	93,553,728	-				-	93,553,728	D1	47.066%	44,031,904
33	31115	Stm Pr-Struc-Addl Amort-100% KS		-				-	-	100% KS	100.000%	-
34	31200	Stm Pr-Boiler Plt Equip-Elec	1,706,742,118	86,149,132				86,149,132	1,792,891,249	D1	47.066%	843,840,403
35	31201	Stm Pr-Boiler-Unit Train-Elec	20,764,028	-				-	20,764,028	D1	47.066%	9,772,776
36	31202	Stm Pr-Boiler AQC Equip-Elec	2,824,017	-				-	2,824,017	D1	47.066%	1,329,149
37	31203	Stm Pr-Boiler-H5 Rebuild	218,184,192	(37,668)				(37,668)	218,146,524	D1	47.066%	102,672,625
38	31204	Stm Pr-Boiler Iatan 2-Elec	666,377,636	(2,215,862)				(2,215,862)	664,161,774	D1	47.066%	312,593,716
39	31213	Stm Pr-Boiler Plt Eq-Iat 1 & Com-Juris Disallow-100% KS	(1,249,901)	-				-	(1,249,901)	100% KS	100.000%	(1,249,901)
40	31214	Stm Pr-Boiler Plt Eq-Iat 2-Juris Disallow-100% KS	(4,477,350)	-				-	(4,477,350)	100% KS	100.000%	(4,477,350)
41	31215	Stm Pr-Boiler-Addl Amort-100% KS		-				-	-	100% KS	100.000%	-
42	31400	Stm Pr-Turbogenerator-Elec	297,461,544	(1,705,479)				(1,705,479)	295,756,065	D1	47.066%	139,200,254

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Total Plant in Service - Schedule 3

Line No.	Account No.	Description	KS Basis For Juris Books Total Co Plant	Adjustments: RB-20 Estimated Net Additions		Adjustments: Charging Stations SEPT17	Adjustments: RB-82 TDC Adj	Total Adjustments	Adjusted Plant	Juris Factor #	Juris Allocation	Electric Juris Adjusted Plant
43	31404	Stm Pr-Turbogen Iatan 2-Elec	226,664,086	(199,755)				(199,755)	226,464,331	D1	47.066%	106,587,475
44	31415	Stm Pr-Turbogen-Addl Amort-100% KS		-				-	-	100% KS	100.000%	-
45	31500	Stm Pr-Accessory Equip-Elec	199,739,519	(1,755,807)				(1,755,807)	197,983,713	D1	47.066%	93,182,816
46	31501	Stm Pr-Acc-H5 Rebuild	33,439,428	(2,897,778)				(2,897,778)	30,541,651	D1	47.066%	14,374,703
47	31502	Stm Pr-Accessory Equip-Comp		-				-	-	D1	47.066%	-
48	31504	Stm Pr-Accessory Iatan 2-Elec	57,773,144	(57,812)				(57,812)	57,715,332	D1	47.066%	27,164,240
49	31515	Stm Pr-Access-Addl Amort-100% KS		-				-	-	100% KS	100.000%	-
50	31600	St Pr-Misc Pwr Plt Equip-Elec	44,212,271	(931,116)				(931,116)	43,281,155	D1	47.066%	20,370,665
51	31601	St Pr-Misc Eq-H5 Rebuild	2,305,161					-	2,305,161	D1	47.066%	1,084,945
52	31604	St Pr-MiscPwr Eq Iatan 2-Elec	4,479,972					-	4,479,972	D1	47.066%	2,108,539
53	31615	St Pr-MiscPwr Eq-Addl Amort-100% KS						-	-	100% KS	100.000%	-
54		**TOTAL STEAM PRODUCTION PLANT**	3,897,997,574	76,568,760	-	-	-	76,568,760	3,974,566,334			1,867,633,747
55	**NUCLEAR PRODUCTION**											
56	32000	Nucl Pr-Land & Land Rights	3,619,298					-	3,619,298	D1	47.066%	1,703,455
57	32100	Nucl Pr-Struct & Improv-Elec	429,176,123	(33,915)				(33,915)	429,142,208	D1	47.066%	201,979,642
58	32200	Nucl Pr-Reactor Plt Eq-Elec	919,320,411	67,491,742				67,491,742	986,812,153	D1	47.066%	464,452,021
59	32300	Nucl Pr-Turbine/Generato-Elec	222,480,652	29,039,668				29,039,668	251,520,320	D1	47.066%	118,380,302
60	32400	Nucl Pr-Accessory Equip-Elec	154,528,174	(294,762)				(294,762)	154,233,412	D1	47.066%	72,591,344
61	32500	Nucl Pr-Misc Pwr Plt Eq-Elec	112,625,539	(12,194)				(12,194)	112,613,345	D1	47.066%	53,002,485
62	32803	Nucl Pr-MPSC Disall-100% KS basis	(115,627,557)	50,882				50,882	(115,576,675)	D1	47.066%	(54,397,202)
63	32805	Nucl Pr-Disal-Pre 1988 Res						-	-	D1	47.066%	-
64		**TOTAL NUCLEAR PRODUCTION PLANT**	1,726,122,641	96,241,421	-	-	-	96,241,421	1,822,364,062			857,712,047
65	**OTHER PRODUCTION**											
66	34000	O h Prod-Land-Elec-CT's	1,008,931					-	1,008,931	D1	47.066%	474,863
67	34001	O h Prod-LandRights-Easements-CT's	93,269					-	93,269	D1	47.066%	43,898
68	34100	O h Prod-Structures-Elec-CT's	8,663,425	(35,515)				(35,515)	8,627,909	D1	47.066%	4,060,803
69	34102	O h Prod-Struct-Elec-Wind	5,073,169	-				-	5,073,169	D1	47.066%	2,387,733
70	34200	O h Prod-Fuel Holders-Elec-CT's	12,097,531	-				-	12,097,531	D1	47.066%	5,693,812
71	34400	O h Prod-Generators-Elec-CT's	293,307,698	427,298				427,298	293,734,996	D1	47.066%	138,249,020
72	34401	O her Prod-Generators-Elect-SOLAR	1,009,191	-				-	1,009,191	D1	47.066%	474,985
73	34402	O h Prod-Generators-Elec-Wind	261,505,902	(348,263)				(348,263)	261,157,639	D1	47.066%	122,916,193
74	34415	O h Prod-Generators-Wind-Addl Amort-100% KS		-				-	-	100% KS	100.000%	-
75	34500	O h Prod-Accessory Equip-Elec-CT's	22,811,832	(15,734)				(15,734)	22,796,098	D1	47.066%	10,729,189
76	34502	O h Prod-Accesry Eq-Elec-Wind	707,218	-				-	707,218	D1	47.066%	332,858
77	34600	O h Prod-Misc Pwr Plt Equip-Elec-CT's	410,607	2,313,287				2,313,287	2,723,894	D1	47.066%	1,282,025
78	34602	O h Prod-Misc Pwr Plt Eq-Wind	165,112					-	165,112	D1	47.066%	77,712
79		**TOTAL OTHER PRODUCTION PLANT**	606,853,885	2,341,073	-	-	-	2,341,073	609,194,958			286,723,090
80		**RETIREMENTS WORK IN PROGRESS-PROD**										
81		Produc ion - Salvage & Removal Retirements not classified						-	-	D1	47.066%	-
82		**TOTAL RETIREMENTS WORK IN PROGRESS-PROD**	$ -	$ -	$ -	$ -	$ -	$ -	$ -			$ -
83		**TOTAL PRODUCTION PLANT**	**$ 6,230,974,099**	**$ 175,151,254**	**$ -**	**$ -**	**$ -**	**$ 175,151,254**	**$ 6,406,125,353**			**$ 3,012,068,884**

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Total Plant in Service - Schedule 3

Line No.	Account No.	Description	KS Basis For Juris Books Total Co Plant	Adjustments: RB-20 Estimated Net Additions	Adjustments: Charging Stations SEPT17	Adjustments: RB-82 TDC Adj	Total Adjustments	Adjusted Plant	Juris Factor #	Juris Allocation	Electric Juris Adjusted Plant
84	**TRANSMISSION PLANT**										
85	35000	Land - Transmission Plant	1,584,661			(1,307,488)	$ (1,307,488)	$ 277,173	D1	47.066%	$ 130,454
86	35001	Land Rights - Transmission Plant	24,976,271			(20,608,088)	(20,608,088)	4,368,183	D1	47.066%	2,055,925
87	35002	Land Rights- TP- Wolf Creek				-	-	-	D1	47.066%	-
88	35200	Structures & Improvements - TP	5,962,658	(26,018)		(4,898,262)	(4,924,281)	1,038,377	D1	47.066%	488,721
89	35201	Structures & Improvements - TP - Wolf Creek	250,476	-		(206,665)	(206,665)	43,811	D1	47.066%	20,620
90	35300	Station Equipment - Transmission Plant	175,818,952	3,008,863		(147,549,041)	(144,540,177)	31,278,775	D1	47.066%	14,721,637
91	35301	Station Equipment - Wolf Creek -TP	15,490,980	-		(12,781,453)	(12,781,453)	2,709,527	D1	47.066%	1,275,263
92	35303	Station Equipment - Communications	7,864,832	(23,480)		(6,469,821)	(6,493,302)	1,371,530	D1	47.066%	645,523
93	35315	Station Equip - Transm Plt-Addl Amort - 100% KS				-	-	-	100% KS	100.000%	-
94	35400	Towers and Fixtures - Transmission Plant	4,287,911	-		(3,537,912)	(3,537,912)	749,998	D1	47.066%	352,993
95	35500	Poles and Fixtures - Transmission Plant	134,412,722	1,235,761		(111,922,206)	(110,686,445)	23,726,277	D1	47.066%	11,166,986
96	35501	Poles & Fixtures - Wolf Creek	58,255	-		(48,066)	(48,066)	10,190	D1	47.066%	4,796
97	35600	Overhead Conductors & Devices - TP	111,602,191	925,593		(92,845,548)	(91,919,956)	19,682,235	D1	47.066%	9,263,621
98	35601	Overhead Conductors & Devices- Wlf Crk	39,418			(32,523)	(32,523)	6,894	D1	47.066%	3,245
99	35700	Underground Conduit	4,100,657			(3,383,411)	(3,383,411)	717,246	D1	47.066%	337,578
100	35800	Underground Conductors & Devices	3,242,114			(2,675,036)	(2,675,036)	567,078	D1	47.066%	266,901
101		Transmission-Salvage & Removal : Retirements not classified	-			-	-	-	D1	47.066%	-
102		**TOTAL TRANSMISSION PLANT**	**$ 489,692,098**	**$ 5,120,718 $ -**	**$ -**	**$ (408,265,520)**	**$ (403,144,802)**	**$ 86,547,296**			**$ 40,734,264**
103	**DISTRIBUTION PLANT**										
104	36000	Distribu ion Land Electric	9,267,377				$ -	$ 9,267,377	360L	49.609%	$ 4,597,462
105	36001	Distribu ion Depreciable Land Rights	16,589,694				-	16,589,694	360LR	41.668%	6,912,527
106	36100	Distribu ion Structures & Improvements	14,957,736	(17,035)			(17,035)	14,940,701	361	43.265%	6,464,154
107	36200	Distribu ion Station Equipment	233,970,661	14,820,955			14,820,955	248,791,616	362	37.878%	94,237,288
108	36203	Distribu ion Station Equipment-Communicatons	4,682,147	(20,437)			(20,437)	4,661,709	362Com	44.168%	2,058,979
109	36300	Distribu ion Energy Storage Equipment	2,413,035	-			-	2,413,035	363	0.000%	-
110	36400	Distribu ion Poles, Tower, & Fixtures	369,264,008	21,216,908			21,216,908	390,480,917	364	45.225%	176,593,042
111	36500	Distribu ion Overhead Conductor	265,503,686	8,643,308			8,643,308	274,146,994	365	43.383%	118,932,368
112	36600	Distribu ion Underground Circuit	292,261,273	2,330,920			2,330,920	294,592,193	366	42.031%	123,819,161
113	36700	Distribu ion Underground Conductors	540,704,388	4,799,408			4,799,408	545,503,796	367	47.218%	257,573,255
114	36800	Distribu ion Line Transformers	310,772,276	625,587			625,587	311,397,862	368	43.262%	134,715,386
115	36900	Distribu ion Services	149,683,863	(209,744)			(209,744)	149,474,119	369	48.342%	72,259,377
116	37000	Distribu ion Meters Electric	54,745,052	3,166,090			3,166,090	57,911,142	370	47.827%	27,697,336
117	37002	Distribu ion AMI Meters Electric	62,056,906	446,621			446,621	62,503,526	370AMI	45.522%	28,452,605
118	37100	Distribu ion Cust Prem Install	14,759,247	(70,377)			(70,377)	14,688,870	371	31.402%	4,612,540
119	37101	Distribu ion Electric Vehicle Charging Stations			11,847,840		11,847,840	11,847,840	371CCN	47.444%	5,621,136
120	37300	Distribu ion Street Light and Traffic Signal	25,771,107	201,675			201,675	25,972,782	373	52.660%	13,677,163
121		Distribu ion-Salvage and removal: Retirements not classified					-	-	Dist Plt	44.302%	-
122		**TOTAL DISTRIBUTION PLANT**	**$ 2,367,402,457**	**$ 55,933,878 $ -**	**$ 11,847,840**	**$ -**	**$ 67,781,718**	**$ 2,435,184,174**			**$ 1,078,223,781**

Filed in Accordance with K A R 21-1-231(c)(4)(D)

Kansas City Power & Light Company
2018 RATE CASE - DIRECT
Kansas Jurisdiction
TY 9/30/17; K&M 6/30/18

Total Plant in Service - Schedule 3

Line No.	Account No.	Description	KS Basis For Juris Books Total Co Plant	Adjustments: RB-20 Estimated Net Additions		Adjustments: Charging Stations SEPT17	Adjustments: RB-82 TDC Adj	Total Adjustments	Adjusted Plant	Juris Factor #	Juris Allocation	Electric Juris Adjusted Plant
123	**GENERAL PLANT**											
124	38900	Land and Land Rights - General Plant	$ 3,546,244				(70,594)	$ (70,594)	$ 3,475,650	PTD	46.271%	$ 1,608,225
125	39000	Structures & Improvements - General Plant	112,511,762	3,332,875			(2,306,085)	1,026,790	113,538,553	PTD	46.271%	52,535,656
126	39003	Struct & Imprv - Leasehold (801 Char)	6,585,712	-			(131,100)	(131,100)	6,454,612	PTD	46.271%	2,986,627
127	39005	Struct & Imprv - Leasehold (One KC Place)	30,215,449	-			(601,490)	(601,490)	29,613,959	PTD	46.271%	13,702,736
128	39100	Office Furniture & Equipment - Gen. Plt	11,081,547	90,840			(222,405)	(131,565)	10,949,982	PTD	46.271%	5,066,689
129	39101	Office Furniture & Equip - Wolf Creek	13,181,505	(472,824)			(252,988)	(725,812)	12,455,693	PTD	46.271%	5,763,399
130	39102	Office Furniture & Equip - Computer	59,858,112	438,143			(1,200,300)	(762,157)	59,095,955	PTD	46.271%	27,344,411
131	39110	Office Furn & Equip-Gen-Unrecovered Res-100% KS					-	-	-	100% KS	100.000%	-
132	39111	Office Furn & Equip-Wlf Crk-Unrecov Res-100% KS					-	-	-	100% KS	100.000%	-
133	39112	Office Furn & Equip-Computer-Unrec Res-100% KS					-	-	-	100% KS	100.000%	-
134	39200	Transporta ion Equipment- Autos	893,773	1,646,285			(50,564)	1,595,721	2,489,494	PTD	46.271%	1,151,919
135	39201	Transporta ion Equipment- Light Trucks	11,668,450	(1,034,707)			(211,683)	(1,246,390)	10,422,060	PTD	46.271%	4,822,413
136	39202	Transporta ion Equipment - Heavy Trucks	39,783,171	(2,259,600)			(746,971)	(3,006,570)	36,776,601	PTD	46.271%	17,016,976
137	39203	Transporta ion Equipment - Tractors	654,808	(46,840)			(12,103)	(58,942)	595,866	PTD	46.271%	275,714
138	39204	Transporta iob Equipment - Trailers	2,132,269	(38,383)			(41,682)	(80,065)	2,052,204	PTD	46.271%	949,580
139	39300	Stores Equipment - General Plant	824,760	(17,124)			(16,077)	(33,201)	791,559	PTD	46.271%	366,264
140	39310	Stores Equip - Gen - Unrecovered Reserve-100% KS		-			-	-	-	100% KS	100.000%	-
141	39400	Tools, Shop, & Garage Equipment-Gen. Plt	7,883,243	379,042			(164,475)	214,567	8,097,810	PTD	46.271%	3,746,954
142	39410	Tools, Shop, & Gar Equip-Gen-Unrecov Res-100% KS		-			-	-	-	100% KS	100.000%	-
143	39500	Laboratory Equipment	7,629,652	(54,168)			(150,803)	(204,971)	7,424,682	PTD	46.271%	3,435,490
144	39510	Laboratory Equipment-Unrecovered Reserve-100% KS		-			-	-	-	100% KS	100.000%	-
145	39600	Power Operated Equipment - Gen. Plt	31,351,982	(545,980)			(613,246)	(1,159,226)	30,192,755	PTD	46.271%	13,970,552
146	39700	Communication Equipment - Gen. Plt	115,092,516	13,164,113			(2,553,166)	10,610,947	125,703,462	PTD	46.271%	58,164,507
147	39710	Communica Equip-Unrecov Res-100% KS		-			-	-	-	100% KS	100.000%	-
148	39701	Communications Equip - Wolf Creek	143,390	-			(2,854)	(2,854)	140,535	PTD	46.271%	65,027
149	39800	Miscellaneous Equipment - Gen. Plt	1,254,910	2,065,063			(66,090)	1,998,973	3,253,883	PTD	46.271%	1,505,611
150	39810	Miscellaneous Equip-Gen-Unrecov Res-100% KS					-			100% KS	100.000%	-
151		Gen Plant-Slvg & removal/retirements not classified					-	-	-	PTD	46.271%	-
152		**TOTAL GENERAL PLANT**	**$ 456,293,252**	**$ 16,646,736**	**$ -**	**$ -**	**$ (9,414,676)**	**$ 7,232,061**	**$ 463,525,313**			**$ 214,478,748**
153		**TOTAL PLANT IN SERVICE**	**$ 9,925,788,646**	**$ 396,900,967**	**$ -**	**$ 11,847,840**	**$ (428,140,672)**	**$ (19,391,865)**	**$ 9,906,396,780**			**$ 4,586,347,518**

Kansas City Power & Light Company
2018 RATE CASE - DIRECT
Kansas Jurisdiction
TY 9/30/17; K&M 6/30/18

Summary of Adjustments

Line No.	Adj No.	Description	Witness	Increase (Decrease)			
	A	B		D	E	F	G
				Adjust to 6-30-18 - Update Date			
				Total Adjustments	Allocated Adjs	100% MO & Whsl Adjs (2)	100% KS Adjs
				Incr (Decr)	Incr (Decr)	Incr (Decr)	Incr (Decr)
	RATE BASE						
	RB-20	Increase plant-in-service for additions and retirements for the period subsequent to the test period through the indicated period	Klote	396,900,967	396,900,967		
	RB-82	Remove plant-in-service for Transmission Delivery Charge Adjustment	Klote	(428,140,672)	(428,140,216)	(457)	
				(31,239,705)	(31,239,248)	(457)	0

(1) All amounts are total company; if an adjustment is applicable to only KS or MO it is so indicated

KANSAS CITY POWER & LIGHT COMPANY

SECTION 4: PLANT INVESTMENTS

Supplemental Plant Investment Schedules, by Primary Account

Source: PowerPlant Asset Management System, Rpt Asset-1061KCP - Financial Basis

Account 101 - Electric Plant In Service - Total Company-Financial Basis

Description	2013	2014	2015	Year September 2016	Test Year September 2017
301 - Organization	72,186.21	72,186.21	72,186.21	72,186.21	72,186.21
302 - Franchises and consents	22,936.96	22,936.96	22,936.96	22,936.96	22,936.96
303 - Misc intangible plant	242,439,716.04	290,154,914.62	328,628,378.13	346,434,344.10	381,331,616.79
310 - Land and land rights	9,607,693.13	9,644,654.56	9,644,654.56	9,644,654.56	9,644,654.56
311 - Structures and Improvements	289,625,369.08	301,089,660.76	374,141,532.06	393,234,533.90	412,392,942.22
312 - Boiler plant equipment	2,071,923,077.04	2,115,997,898.71	2,525,338,667.51	2,516,093,246.48	2,603,972,686.13
314 - Turbogenerator units	490,066,703.83	493,928,411.07	503,992,388.11	495,239,795.21	523,410,154.60
315 - Accessory electric equipment	272,554,630.10	283,153,584.90	312,111,041.07	311,019,946.12	290,090,417.90
316 - Misc power plant equipment	49,248,316.32	48,628,334.24	54,721,498.85	55,388,743.31	50,970,657.83
317-Asset Retirement Costs Steam	12,623,857.09	16,227,607.99	68,996,685.56	75,527,922.91	115,878,938.05
320 - Land and land rights	3,536,678.67	3,474,780.29	3,474,780.29	3,619,298.06	3,619,298.06
321 - Structures and improvements	424,249,637.85	426,957,844.92	552,331,229.32	432,140,953.10	448,327,641.49
322 - Reactor plant equipment	616,751,232.24	761,311,073.79	691,209,830.28	803,943,259.29	837,875,528.60
323 - Turbogenerator units	213,542,744.32	226,520,706.61	226,224,894.53	221,923,998.23	226,569,679.21
324 - Accessory electric equipment	135,986,578.52	140,000,177.43	145,728,937.64	145,472,866.28	160,365,987.03
325 - Misc power plant equipment	111,053,158.16	114,166,481.68	116,691,714.49	130,954,509.27	113,683,859.51
326-Asset Retirement Costs Nuclear	-	23,127,804.88	23,127,804.88	23,127,804.88	5,584,243.24
340 - Land and land rights	1,102,200.71	1,102,200.71	1,102,200.71	1,102,200.71	1,102,200.71
341 - Structures and improvements	10,905,429.52	11,497,259.58	13,101,272.93	12,499,881.58	13,736,594.06
342 - Fuel holders,producrs,accessr	11,829,540.83	11,829,540.83	12,083,281.54	12,083,279.46	12,097,530.69
344 - Generators	530,882,111.25	532,556,943.15	554,985,148.36	555,579,210.75	555,822,790.38
345 - Accessory electric equipment	22,888,308.95	23,524,539.45	23,593,158.72	23,598,218.59	23,519,049.78
346 - Misc power plant equipment	437,734.83	171,254.73	415,098.39	455,483.59	575,719.09
347 - Oth Pro-Wind ARC	5,049,156.99	5,049,156.99	5,049,156.99	5,049,156.99	5,049,156.99
350 - Land and land rights	26,561,791.64	26,561,791.64	26,561,287.32	26,561,287.32	26,561,287.32
352 - Structures and improvements	5,783,019.65	5,845,533.64	5,972,505.18	6,214,243.95	6,228,828.17
353 - Station equipment	168,004,638.30	177,142,900.50	181,508,226.96	192,358,638.93	199,707,238.71
354 - Towers and fixtures	4,287,910.56	4,287,910.56	4,287,910.56	4,287,910.56	4,287,910.56
355 - Poles and fixtures	118,295,618.38	120,779,029.87	127,734,896.56	130,041,570.91	134,474,483.49
356 - Overhead conductors, devices	102,070,823.00	103,565,495.39	108,533,377.48	110,846,645.46	111,644,160.53
357 - Underground conduit	3,648,880.12	3,648,880.12	3,648,880.12	4,100,619.21	4,100,656.99
358 - Undergrnd conductors, devices	3,120,096.59	3,120,096.59	3,120,096.59	3,242,083.19	3,242,114.11
360 - Land and land rights	24,756,658.76	25,886,306.32	25,823,640.87	25,858,016.47	25,857,071.03
361 - Structures and improvements	12,578,416.57	12,613,829.93	14,678,004.36	14,753,545.74	14,957,736.38
362 - Station equipment	195,657,377.88	201,074,732.25	220,495,072.16	228,557,735.93	238,652,808.01
363 - Storage battery equipment		2,502,752.32	2,502,752.32	2,413,034.56	2,413,034.56
364 - Poles, towers and fixtures	289,349,912.27	320,447,528.65	337,538,177.42	351,805,164.57	369,281,318.69
365 - Overhead conductors, devices	225,510,351.71	233,957,845.76	246,716,511.95	254,737,355.17	265,503,686.43
366 - Underground conduit	248,355,045.55	254,233,023.50	275,636,029.16	283,633,558.59	292,261,273.06
367 - Undergrnd conductors, devices	443,252,645.80	463,703,075.65	490,831,007.28	508,713,778.94	540,704,387.68
368 - Line transformers	269,824,398.56	279,839,247.39	288,464,821.90	296,859,284.62	310,772,275.87
369 - Services	116,323,178.45	123,954,497.95	131,501,626.32	140,765,941.82	149,683,863.09
370 - Meters	97,124,141.81	119,435,830.60	124,743,741.77	115,117,215.83	116,801,957.89
371 - Installs customer premise	10,885,397.44	15,753,636.64	20,066,503.99	23,785,621.05	15,212,682.01
373 - Street lighting,signal system	35,956,922.74	34,939,507.92	35,533,850.37	36,193,229.46	25,771,107.11
389 - Land and land rights	2,884,805.36	2,856,241.36	2,811,125.36	2,821,125.36	3,546,243.91
390 - Structures and improvements	108,026,763.91	110,252,797.79	146,043,816.67	142,292,275.10	149,312,922.94
391 - Office furniture, equipment	29,747,128.68	37,976,655.86	48,815,540.34	64,103,181.15	84,121,163.76
392 - Transportation equipment	49,073,112.81	50,662,540.18	53,813,767.12	55,480,802.84	55,132,470.81
393 - Stores equipment	821,838.07	785,031.50	777,896.06	783,133.92	824,759.64
394 - Tools, shop, garage equipment	5,010,761.63	5,187,776.99	5,811,942.58	7,514,691.36	7,883,242.61
395 - Laboratory equipment	6,796,213.03	7,100,912.04	7,240,193.40	7,414,068.27	7,629,652.17
396 - Power operated equipment	24,868,530.68	25,254,109.06	27,990,202.63	28,306,146.09	31,351,981.65
397 - Communication equipment	109,859,661.34	111,629,241.82	111,511,631.36	112,433,600.81	115,245,185.01
398 - Miscellaneous equipment	555,413.65	556,546.05	1,336,454.60	1,126,886.13	1,254,909.68
Grand Total	**8,265,390,453.58**	**8,725,765,260.90**	**9,628,839,968.85**	**9,757,350,823.85**	**10,110,138,883.96**
Less: Asset Retirement Costs Not Included in Rate Base					
317-Asset Retirement Costs Steam	12,623,857.09	16,227,607.99	68,996,685.56	75,527,922.91	115,878,938.05
326-Asset Retirement Costs Nuclear	-	23,127,804.88	23,127,804.88	23,127,804.88	5,584,243.24
347 - Oth Pro-Wind ARC	5,049,156.99	5,049,156.99	5,049,156.99	5,049,156.99	5,049,156.99
	17,673,014.08	44,404,569.86	97,173,647.43	103,704,884.78	126,512,338.28
Total Plant Excl Asset Retirement Costs	**8,247,717,439.50**	**8,681,360,691.04**	**9,531,666,321.42**	**9,653,645,939.07**	**9,983,626,545.68**

SECTION 5

ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION

Kansas City Power & Light Company
2018 RATE CASE - DIRECT
Kansas Jurisdiction
TY 9/30/17; K&M 6/30/18

Depreciation Reserve - Schedule 6

Line No.	Account Number	Depreciation Reserve Description	KS Basis For Juris Books Tot Co Reserve	Adjustments RB-30 Projected Net Activity		Adjustments Charging Stations SEP17	Adjustments RB-82 TDC Adj	Total Adjustments	Adjusted Reserve	Juris Factor #	Juris Allocation	Electric Juris Adjusted Plant
	A	B	C	D	E	E	G	H	I	J	K	L
1	**INTANGIBLE PLANT**											
2	30100	Organization						$ -	$ -	PTD	46.271%	$ -
3	30200	Franchises and Consents						-	-	100% MO	0.000%	-
4	30301	Miscellaneous Intangibles (Like 353)	590,203	17,695			(12,101)	5,593	595,796	D1	47.066%	280,417
5		Misc Intang Plant-5-Year Software, excl Wlf Crk					-					
6	30302	Customer Related	40,393,853	13,492,165			(1,072,693)	12,419,473	52,813,326	C1	47.395%	25,030,929
7	30302	Energy Related	9,238,303	-			(183,904)	(183,904)	9,054,399	E1	43.590%	3,946,767
8	30302	Demand Related	26,453,885	-			(526,610)	(526,610)	25,927,275	D1	47.066%	12,202,905
9	30302	Corporate Software	21,042,904	-			(418,895)	(418,895)	20,624,009	Sal&Wg	46.407%	9,570,972
10	30302	Transmission Related	3,828,595	-			(76,215)	(76,215)	3,752,380	D1	47.066%	1,766,092
11		Miscl Intangible Plt - 10 yr Software					-					
12	30303	Customer Related	55,877,122	9,515,109			(1,301,744)	8,213,365	64,090,487	C1	47.395%	30,375,750
13	30303	Energy Related	26,366,620	-			(524,872)	(524,872)	25,841,748	E1	43.590%	11,264,289
14	30303	Demand Related	11,869,389	-			(236,280)	(236,280)	11,633,109	D1	47.066%	5,475,227
15	30303	Corporate Software	11,833,685	-			(235,570)	(235,570)	11,598,115	Sal&Wg	46.407%	5,382,331
16	30305	Miscl Intang Plt - WC 5yr Software	19,993,044	784,787			(413,618)	371,169	20,364,214	D1	47.066%	9,584,600
17	303XX	Miscl Intang Plt - 15yr Software		1,382,012			(27,511)	1,354,501	1,354,501	D1	47.066%	637,508
18	30307	Miscl Intg Plt-Srct (Like 312)	11,021	837			(236)	601	11,622	D1	47.066%	5,470
19	30308	Miscl Intang Trans Line (Like 355)	863,021	103,113			(19,233)	83,881	946,902	D1	47.066%	445,668
20	30309	Miscl Intang Trans Ln MINT Line	16,009	2,693			(372)	2,321	18,330	D1	47.066%	8,627
21	30310	Miscl Intang-Iatan Hwy & Bridge	373,784	43,304			(8,303)	35,001	408,785	D1	47.066%	192,398
22	30311	Misc Intan-LaCygne Road Overpass	30,342	11,626			(835)	10,791	41,133	D1	47.066%	19,359
23	30312	Misc Intan-Montrose Highway	7,480	6,411			(277)	6,134	13,614	D1	47.066%	6,407
24	30313	Misc Intan-Radio Frequencies	562,103	111,232			(13,404)	97,828	659,930	D1	47.066%	310,602
25		**TOTAL PLANT INTANGIBLE**	**$ 229,351,363**	**$ 25,470,984**	**$ -**	**$ -**	**$ (5,072,672)**	**$ 20,398,312**	**$ 249,749,675**			**$ 116,506,320**
26	**PRODUCTION PLANT**											
27	**STEAM PRODUCTION**											
28	31000	Sm Pr-Land						-	-	D1	47.066%	-
29	31100	Stm Pr-Structures-Elec	71,720,907	(2,473,047)				(2,473,047)	69,247,860	D1	47.066%	32,592,129
30	31101	Stm Pr-Struc-Lshd Impr-P&M	705,849	87,095				87,095	792,944	D1	47.066%	373,206
31	31102	Stm Pr-Struc-H5 Rebuild	7,905,947	31,802				31,802	7,937,748	D1	47.066%	3,735,973
32	31104	Stm Pr-Structure Iatan 2-Elec	12,251,981	1,217,023				1,217,023	13,469,004	D1	47.066%	6,339,308
33	31115	Stm Pr-Struc-Addl Amort-100% KS	5,931,817	-				-	5,931,817	100% KS	100.000%	5,931,817
34	31200	Stm Pr-Boiler Plt Equip-Elec	465,082,429	23,336,329				23,336,329	488,418,758	D1	47.066%	229,878,684
35	31201	Stm Pr-Boiler-Unit Train-Elec	9,353,625	451,618				451,618	9,805,243	D1	47.066%	4,614,926
36	31202	Stm Pr-Boiler AQC Equip-Elec	59,410,972	-				-	59,410,972	D1	47.066%	27,962,308
37	31203	Stm Pr-Boiler-H5 Rebuild	197,821,061	1,107,700				1,107,700	198,928,761	D1	47.066%	93,627,612
38	31204	Stm Pr-Boiler Iatan 2-Elec	100,330,693	8,105,066				8,105,066	108,435,760	D1	47.066%	51,036,266
39	31213	Stm Pr-Boiler Plt Eq-Iat 1 & Com.-Juris Disallow-100% KS	(198,526)	-				-	(198,526)	100% KS	100.000%	(198,526)
40	31214	Stm Pr-Boiler Plt Eq-Iat 2-Juris Disallow-100% KS	(644,365)	-				-	(644,365)	100% KS	100.000%	(644,365)
41	31215	Stm Pr-Boiler-Addl Amort-100% KS	47,084,753	-				-	47,084,753	100% KS	100.000%	47,084,753

Filed in Accordance with K A R 21-1-231(c)(4)(E)

Kansas City Power & Light Company
2018 RATE CASE - DIRECT
Kansas Jurisdiction
TY 9/30/17; K&M 6/30/18

Depreciation Reserve - Schedule 6

Line No.	Account Number	Depreciation Reserve Description	KS Basis For Juris Books Tot Co Reserve	Adjustments: RB-30 Projected Net Activity		Adjustments: Charging Stations SEP17	Adjustments: RB-82 TDC Adj	Total Adjustments	Adjusted Reserve	Juris Factor #	Juris Allocation	Electric Juris Adjusted Plant
42	31400	Stm Pr-Turbogenerator-Elec	105,958,335	3,146,641				3,146,641	109,104,976	D1	47.066%	51,351,239
43	31404	Stm Pr-Turbogen Iatan 2-Elec	24,589,800	2,915,077				2,915,077	27,504,876	D1	47.066%	12,945,418
44	31415	Stm Pr-Turbogen - Iatan 2 -Add Amort -100%KS	8,798,405	-				-	8,798,405	100% KS	100.000%	8,798,405
45	31500	Stm Pr-Accessory Equip-Elec	56,770,364	2,334,880				2,334,880	59,105,244	D1	47.066%	27,818,415
46	31501	Stm Pr-Acc-H5 Rebuild	29,715,813	(2,698,636)				(2,698,636)	27,017,177	D1	47.066%	12,715,877
47	31502	Stm Pr-Accessory Equip-Comp		-				-	-	D1	47.066%	-
48	31504	Stm Pr-Accessory Iatan 2-Elec	7,038,357	753,004				753,004	7,791,361	D1	47.066%	3,667,074
49	31515	Stm Pr-Access-Addl Amort-100% KS	3,151,783	-				-	3,151,783	100% KS	100.000%	3,151,783
50	31600	St Pr-Misc Pwr Plt Equip-Elec	17,870,960	(127,103)				(127,103)	17,743,857	D1	47.066%	8,351,306
51	31601	St Pr-Misc Eq-H5 Rebuild	2,103,183	9,509				9,509	2,112,691	D1	47.066%	994,357
52	31604	St Pr-MiscPwr Eq Iatan 2-Elec	439,060	37,741				37,741	476,801	D1	47.066%	224,411
53	31615	St Pr-MiscPwr Eq-Addl Amort-100% KS	875,350					-	875,350	100% KS	100.000%	875,350
54		**TOTAL STEAM PRODUCTION PLANT**	1,234,068,553	38,234,698	-	-	-	38,234,698	1,272,303,251			633,227,727
55	**NUCLEAR PRODUCTION**											
56	32000	Nucl Pr-Land & Land Rights						-	-	D1	47.066%	-
57	32100	Nucl Pr-Struct & Improv-Elec	267,008,228	4,506,087				4,506,087	271,514,315	D1	47.066%	127,790,656
58	32200	Nucl Pr-Reactor Plt Eq-Elec	432,894,212	13,672,076				13,672,076	446,566,287	D1	47.066%	210,180,442
59	32300	Nucl Pr-Turbine/Generato-Elec	91,792,645	3,709,804				3,709,804	95,502,448	D1	47.066%	44,949,087
60	32400	Nucl Pr-Accessory Equip-Elec	73,669,371	1,918,702				1,918,702	75,588,073	D1	47.066%	35,576,207
61	32500	Nucl Pr-Misc Pwr Plt Eq-Elec	33,796,723	1,808,564				1,808,564	35,605,288	D1	47.066%	16,757,949
62	32803	Nucl Pr-MPSC Disall-100% KS basis	(69,081,598)	(1,657,158)				(1,657,158)	(70,738,757)	D1	47.066%	(33,293,833)
63	32805	Nucl Pr-Disal-Pre 1988 Res	(11,891,311)					-	(11,891,311)	D1	47.066%	(5,596,753)
64		**TOTAL NUCLEAR PRODUCTION PLANT**	818,188,269	23,958,074	-	-	-	23,958,074	842,146,343			396,363,756
65	**OTHER PRODUCTION**											
66	34000	Oth Prod-Land-Elec-CT's						-	-	D1	47.066%	-
67	34001	Oth Prod-LandRights-Easements-CT's	566					-	566	D1	47.066%	267
68	34100	Oth Prod-Structures-Elec-CT's	2,049,092	125,052				125,052	2,174,145	D1	47.066%	1,023,281
69	34102	Oth Prod-Struct-Elec-Wind	2,361,935	196,712				196,712	2,558,647	D1	47.066%	1,204,250
70	34200	Oth Prod-Fuel Holders-Elec-CT's	5,660,403	236,862				236,862	5,897,266	D1	47.066%	2,775,601
71	34400	Oth Prod-Generators-Elec-CT's	141,604,394	5,655,727				5,655,727	147,260,121	D1	47.066%	69,309,301
72	34401	Other Prod-Generators-Elect-SOLAR	162,580	22,328				22,328	184,908	D1	47.066%	87,029
73	34402	Oth Prod-Generators-Elec-Wind	111,562,031	9,043,550				9,043,550	120,605,582	D1	47.066%	56,764,103
74	34415	Oth Prod-Generators-Wind-Addl Amort-100% KS	5,740,000	-				-	5,740,000	100% KS	100.000%	5,740,000
75	34500	Oth Prod-Accessory Equip-Elec-CT's	13,354,785	340,025				340,025	13,694,809	D1	47.066%	6,445,585
76	34502	Oth Prod-Accesry Eq-Elec-Wind	195,601	29,332				29,332	224,933	D1	47.066%	105,867
77	34600	Oth Prod-Misc Pwr Plt Equip-Elec-CT's	44,153	40,082				40,082	84,236	D1	47.066%	39,646
78	34602	Oth Prod-Misc Pwr Plt Eq-Wind	18,794	5,956				5,956	24,750	D1	47.066%	11,649
79		**TOTAL OTHER PRODUCTION PLANT**	282,754,335	15,695,628	-	-	-	15,695,628	298,449,964			143,506,579
80		**RETIREMENTS WORK IN PROGRESS-PROD**										
81		Production - Salvage & Removal Retirements not classified	(47 852 035)	8,355,888				8,355,888	(39,496,147)	D1	47.066%	(18,589,217)
82		**TOTAL RETIREMENTS WORK IN PROGRESS-PROD**	**$ (47,852,035)**	**$ 8,355,888**	**$ -**	**$ -**	**$ -**	**$ 8,355,888**	**$ (39,496,147)**			**$ (18,589,217)**
83		**TOTAL PRODUCTION PLANT**	**$ 2,287,159,122**	**$ 86,244,289**	**$ -**	**$ -**	**$ -**	**$ 86,244,289**	**$ 2,373,403,411**			**$ 1,154,508,844**

Filed in Accordance with K A R 21-1-231(c)(4)(E)

Kansas City Power & Light Company
2018 RATE CASE - DIRECT
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Depreciation Reserve - Schedule 6

Line No.	Account Number	Depreciation Reserve Description	KS Basis For Juris Books Tot Co Reserve	Adjustments: RB-30 Projected Net Activity	Adjustments: Charging Stations SEP17	Adjustments: RB-82 TDC Adj	Total Adjustments	Adjusted Reserve	Juris Factor #	Juris Allocation	Electric Juris Adjusted Plant
84	**TRANSMISSION PLANT**										
85	35000	Land - Transmission Plant				-	$ -	$ -	D1	47.066%	$ -
86	35001	Land Rights - Transmission Plant	1,340,155			(1,105,748)	(1,105,748)	234,406	D1	47.066%	110,326
87	35002	Land Rights- TP- Wolf Creek	-			-	-	-	D1	47.066%	-
88	35200	Structures & Improvements - TP	2,579,764	36,907		(2,158,989)	(2,122,082)	457,682	D1	47.066%	215,412
89	35201	Structures & Improvements - TP - Wolf Creek	150,705	2,649		(126,530)	(123,882)	26,823	D1	47.066%	12,625
90	35300	Station Equipment - Transmission Plant	64,320,587	886,157		(53,801,432)	(52,915,275)	11,405,313	D1	47.066%	5,368,013
91	35301	Station Equipment - Wolf Creek -TP	7,047,576	134,771		(5,926,083)	(5,791,312)	1,256,264	D1	47.066%	591,272
92	35303	Station Equipment - Communica ions	14,747,400	1,393,994		(13,318,102)	(11,924,109)	2,823,291	D1	47.066%	1,328,807
93	35315	Station Equip - Transm Plt-Addl Amort - 100% KS	167,891	-		(138,525)	(138,525)	29,366	100% KS	100.000%	29,366
94	35400	Towers and Fixtures - Transmission Plant	4,433,317	13,829		(3,669,296)	(3,655,467)	777,850	D1	47.066%	366,102
95	35500	Poles and Fixtures - Transmission Plant	74,850,645	1,704,003		(63,164,474)	(61,460,471)	13,390,174	D1	47.066%	6,302,206
96	35501	Poles & Fixtures - Wolf Creek	69,639	874		(58,179)	(57,305)	12,333	D1	47.066%	5,805
97	35600	Overhead Conductors & Devices - TP	55,931,050	191,541		(46,306,189)	(46,114,648)	9,816,403	D1	47.066%	4,620,178
98	35601	Overhead Conductors & Devices- Wlf Crk	30,346	89		(25,111)	(25,023)	5,323	D1	47.066%	2,505
99	35700	Underground Conduit	2,590,459	25,834		(2,158,678)	(2,132,843)	457,616	D1	47.066%	215,381
100	35800	Underground Conductors & Devices	2,323,574	48,632		(1,957,283)	(1,908,651)	414,922	D1	47.066%	195,287
101		Transmission-Salvage & Removal : Retirements not classified	(852,054)	(219,248)		883,921	664,673	(187,382)	D1	47.066%	(88,193)
102		**TOTAL TRANSMISSION PLANT**	**$ 229,731,054**	**$ 4,220,030 $ -**	**$ -**	**$ (193,030,699)**	**$ (188,810,668)**	**$ 40,920,385**			**$ 19,275,092**
103	**DISTRIBUTION PLANT**										
104	36000	Distribution Land Electric					$ -	$ -	360L	49.609%	$ -
105	36001	Distribution Depreciable Land Rights	266,550				-	266,550	360LR	41.668%	111,065
106	36100	Distribution Structures & Improvements	6,110,172	184,023			184,023	6,294,196	361	43.265%	2,723,209
107	36200	Distribution Sta ion Equipment	85,197,789	1,182,567			1,182,567	86,380,356	362	37.878%	32,719,151
108	36203	Distribution Sta ion Equipment-Communicatons	7,836,805	737,116			737,116	8,573,921	362Com	44.168%	3,786,921
109	36300	Distribution Energy Storage Equipment	-	-			-	-	363	0.000%	-
110	36400	Distribution Poles, Tower, & Fixtures	170,303,467	4,782,297			4,782,297	175,085,763	364	45.225%	79,181,661
111	36500	Distribution Overhead Conductor	93,980,657	3,298,535			3,298,535	97,279,192	365	43.383%	42,202,340
112	36600	Distribution Underground Circuit	58,407,584	1,387,765			1,387,765	59,795,349	366	42.031%	25,132,404
113	36700	Distribution Underground Conductors	154,392,079	2,211,992			2,211,992	156,604,071	367	47.218%	73,944,527
114	36800	Distribution Line Transformers	149,447,882	1,204,497			1,204,497	150,652,379	368	43.262%	65,174,479
115	36900	Distribution Services	79,801,669	5,642,945			5,642,945	85,444,613	369	48.342%	41,305,977
116	37000	Distribution Meters Electric	15,663,762	2,494,815			2,494,815	18,158,576	370	47.827%	8,684,757
117	37002	Distribution AMI Meters Electric	6,111,317	1,557,815			1,557,815	7,669,132	370AMI	45.522%	3,491,112
118	37100	Distribution Cust Prem Install	12,634,283	(83,396)			(83,396)	12,550,887	371	31.402%	3,941,179
119	37101	Distribution Electric Vehicle Charging Stations			1,522,998		1,522,998	1,522,998	371CCN	47.444%	722,577
120	37300	Distribution Street Light and Traffic Signal	10,779,200	(1,468,753)			(1,468,753)	9,310,448	373	52.660%	4,902,845
121		Distribution-Salvage and removal: Retirements not classified	(6,472,316)	402,760			402,760	(6,069,556)	Dist Plt	44.302%	(2,688,957)
122		**TOTAL DISTRIBUTION PLANT**	**$ 844,460,901**	**$ 23,534,978 $ -**	**$ 1,522,998**	**$ -**	**$ 25,057,975**	**$ 869,518,877**			**$ 385,335,247**

Kansas City Power & Light Company
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Depreciation Reserve - Schedule 6

Line No.	Account Number	Depreciation Reserve Description	KS Basis For Juris Books Tot Co Reserve	Adjustments RB-30 Projected Net Activity	Adjustments Charging Stations SEP17	Adjustments RB-82 TDC Adj	Total Adjustments	Adjusted Reserve	Juris Factor #	Juris Allocation	Electric Juris Adjusted Plant
123	**GENERAL PLANT**										
124	38900	Land and Land Rights - General Plant					$ -	$ -	PTD	46.271%	$ -
125	39000	Structures & Improvements - General Plant	22,351,008	1,245,440		(469,727)	775,712	23,126,720	PTD	46.271%	10,701,012
126	39003	Struct & Imprv - Leasehold (801 Char)	3,104,479	333,310		(68,435)	264,874	3,369,353	PTD	46.271%	1,559,040
127	39005	Struct & Imprv - Leasehold (One KC Place)	9,947,091	1,013,418		(218,188)	795,230	10,742,321	PTD	46.271%	4,970,601
128	39100	Office Furniture & Equipment - Gen. Plt	1,737,728	673,051		(47,991)	625,060	2,362,789	PTD	46.271%	1,093,291
129	39101	Office Furniture & Equip - Wolf Creek	3,103,948	40,764		(62,601)	(21,837)	3,082,112	PTD	46.271%	1,426,130
130	39102	Office Furniture & Equip - Computer	25,480,543	10,461,283		(715,483)	9,745,799	35,226,342	PTD	46.271%	16,299,653
131	39110	Office Furn & Equip-Gen-Unrecovered Res-100% KS		139,209		(2,771)	136,438	136,438	100% KS	100.000%	136,438
132	39111	Office Furn & Equip-Wolf Creek-Unrecov Res-100% KS		13,212		(263)	12,949	12,949	100% KS	100.000%	12,949
133	39112	Office Furn & Equip-Computer-Unrec Res-100% KS		2,638		(53)	2,585	2,585	100% KS	100.000%	2,585
134	39200	Transportation Equipment- Autos	515,391	95,963		(12,170)	83,793	599,185	PTD	46.271%	277,250
135	39201	Transportation Equipment- Light Trucks	3,909,036	183,947		(81,478)	102,469	4,011,505	PTD	46.271%	1,856,172
136	39202	Transportation Equipment - Heavy Trucks	14,135,747	422,337		(289,803)	132,534	14,268,281	PTD	46.271%	6,602,105
137	39203	Transportation Equipment - Tractors	531,035	(14,118)		(10,290)	(24,408)	506,627	PTD	46.271%	234,422
138	39204	Transportatiob Equipment - Trailers	1,105,395	10,635		(22,216)	(11,581)	1,093,814	PTD	46.271%	506,121
139	39300	Stores Equipment - General Plant	431,364	6,392		(8,714)	(2,323)	429,041	PTD	46.271%	198,523
140	39310	Stores Equip - Gen - Unrecovered Reserve-100% KS		(1,642)		33	(1,609)	(1,609)	100% KS	100.000%	(1,609)
141	39400	Tools, Shop, & Garage Equipment-Gen. Plt	2,995,994	181,414		(63,252)	118,163	3,114,156	PTD	46.271%	1,440,958
142	39410	Tools, Shop, & Gar Equip-Gen-Unrecov Res-100% KS		980		(20)	961	961	100% KS	100.000%	961
143	39500	Laboratory Equipment	3,844,593	177,277		(80,062)	97,215	3,941,808	PTD	46.271%	1,823,922
144	39510	Laboratory Equipment-Unrecovered Reserve-100% KS		33,498		(667)	32,831	32,831	100% KS	100.000%	32,831
145	39600	Power Operated Equipment - Gen. Plt	14,496,798	(732,858)		(273,995)	(1,006,853)	13,489,944	PTD	46.271%	6,241,960
146	39700	Communication Equipment - Gen. Plt	62,200,288	2,342,652		(1,284,837)	1,057,815	63,258,103	PTD	46.271%	29,270,287
147	39710	Communica Equip-Unrecov Res-100% KS		1,060,595		(21,113)	1,039,482	1,039,482	100% KS	100.000%	1,039,482
148	39701	Communications Equip - Wolf Creek	122,781	5,343,983		(108,825)	5,235,158	5,357,938	PTD	46.271%	2,479,183
149	39800	Miscellaneous Equipment - Gen. Plt	351,056	55,534		(8,094)	47,440	398,496	PTD	46.271%	184,389
150	39810	Miscellaneous Equip-Gen-Unrecov Res-100% KS		(2,047)		41	(2,006)	(2,006)	100% KS	100.000%	(2,006)
151		Gen Plant-Slvg & removal/retirements not classified	357,932	(259,818)		(1,953)	(261,771)	96,160	PTD	46.271%	44,495
152		**TOTAL GENERAL PLANT**	**$ 170,722,206**	**$ 22,827,048 $ -**	**$ -**	**$ (3,852,927)**	**$ 18,974,121**	**$ 189,696,327**			**$ 88,431,144**
153		**TOTAL DEPRECIATION RESERVE**	**$ 3,761,424,646**	**$ 162,297,328 $ -**	**$ 1,522,998**	**$ (201,956,298)**	**$ (38,135,971)**	**$ 3,723,288,675**			**$ 1,764,056,647**

Kansas City Power & Light Company
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Summary of Adjustments

Line No.	Adj No.	Description	Witness	Increase (Decrease)			
	A	B		D	E	F	G
				Adjust to 6-30-18 - Update Date			
				Total Adjustments Incr (Decr)	Allocated Adjs Incr (Decr)	100% MO & Whsl Adjs (2) Incr (Decr)	100% KS Adjs Incr (Decr)
	RATE BASE						
	RB-30	Adjust test year KS basis Accumulated Plant Reserve to Projected KS basis balance at the Update Date	Klote	162,297,328	161,050,884		1,246,444
	RB-82	Remove Accumulated Plant Reserve for Transmission Delivery Charge Adjustment	Klote	(201,956,298)	(201,792,960)		(163,338)
				(39,658,969)	(40,742,075)	0	1,083,106

(1) All amounts are total company; if an adjustment is applicable to only KS or MO it is so indicated

KANSAS CITY POWER & LIGHT COMPANY
SECTION 5: ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION
Supplemental Plant Reserve Schedules, by Primary Account

Source: PowerPlant Asset Management System, Rpt Depr-1033 FIN - Financial Basis

Account 108/111 - Electric Accumlated Provision for Depreciation and Amort - Total Company-Financial Basis

	2013	2014	2015	12 Mos Prior to Test Year September 2016	Test Year September 2017
301 - Organization	-	-	-	-	-
302 - Franchises and consents	-	-	-	-	-
303 - Misc intangible plant	157,558,295.80	176,727,376.63	179,256,095.28	197,608,423.79	229,468,172.40
310 - Land and land rights	-	-	-	-	-
311 - Structures and Improvements	107,324,887.39	110,594,538.70	112,698,740.60	114,466,314.25	121,908,831.80
312 - Boiler plant equipment	941,064,368.24	976,521,857.39	933,678,692.39	930,408,222.13	963,499,497.43
314 - Turbogenerator units	164,683,787.42	170,631,800.87	175,051,409.25	170,828,256.06	178,315,809.10
315 - Accessory electric equipment	104,678,162.94	107,605,100.16	107,015,576.60	108,878,264.89	110,556,857.76
316 - Misc power plant equipment	20,596,412.17	21,485,418.26	21,281,017.10	20,514,483.34	20,470,158.16
317-Asset Retirement Costs Steam	8,654,188.50	9,285,443.21	21,767,936.06	25,800,465.08	41,490,317.19
320 - Land and land rights	-	-	-	-	-
321 - Structures and improvements	266,932,001.60	273,100,798.26	279,417,538.34	283,583,194.41	289,330,483.96
322 - Reactor plant equipment	422,204,338.37	429,637,989.41	443,086,044.71	454,080,783.67	468,230,768.67
323 - Turbogenerator units	89,189,532.57	86,650,729.26	91,038,547.59	91,846,022.42	96,299,786.63
324 - Accessory electric equipment	70,269,186.99	73,066,062.59	75,442,058.56	77,515,960.05	79,936,483.07
325 - Misc power plant equipment	26,860,335.71	29,594,925.64	32,618,748.95	34,562,516.67	37,259,864.59
326-Asset Retirement Costs Nuclear	-	576,992.87	1,153,986.07	1,586,730.54	2,123,578.03
328-Nucl Pr-Disall-Mo Gr Up AFDC	(83,483,390.84)	(84,246,013.86)	(86,391,065.66)	(87,989,748.51)	(90,117,275.54)
340 - Land and land rights	6,703.53	7,300.41	7,904.31	8,351.97	8,941.92
341 - Structures and improvements	2,929,899.71	3,358,420.57	3,806,902.50	4,030,868.59	4,485,324.75
342 - Fuel holders,producrs,accessr	4,854,846.37	5,199,086.05	5,506,400.61	5,606,869.48	5,893,399.57
344 - Generators	206,748,057.89	225,236,065.66	242,985,040.85	256,846,165.89	274,148,090.06
345 - Accessory electric equipment	12,306,531.08	12,394,091.27	12,894,173.12	12,955,646.80	13,418,412.22
346 - Misc power plant equipment	3,302.78	6,114.95	19,676.46	40,097.39	62,860.65
347 - Oth Pro-Wind ARC	1,478,204.63	1,730,662.55	1,983,120.46	2,172,463.87	2,424,921.74
350 - Land and land rights	5,417,629.24	5,577,483.84	5,739,076.50	5,858,964.33	6,016,941.51
352 - Structures and improvements	2,044,602.13	2,134,633.48	2,225,145.65	2,294,367.86	2,363,342.72
353 - Station equipment	56,035,335.40	59,002,600.83	62,750,429.74	64,418,399.83	67,398,643.21
354 - Towers and fixtures	3,955,385.48	3,984,114.44	4,013,164.97	4,034,711.69	4,063,440.65
355 - Poles and fixtures	62,488,331.96	64,188,877.76	65,742,020.66	66,944,215.11	69,396,930.43
356 - Overhead conductors, devices	52,920,866.01	53,602,981.06	54,285,348.05	54,849,363.97	56,026,200.42
357 - Underground conduit	2,176,488.37	2,221,369.57	2,265,794.68	2,300,513.14	2,347,362.96
358 - Undergrnd conductors, devices	2,351,918.32	2,396,535.76	2,439,671.05	2,471,083.15	2,513,230.49
360 - Land and land rights	4,689,950.93	4,900,633.61	5,111,453.33	5,269,470.20	5,480,159.36
361 - Structures and improvements	5,913,660.20	6,120,222.94	6,328,776.65	6,470,409.03	6,659,320.98
362 - Station equipment	72,164,886.53	75,817,708.43	80,178,246.79	83,071,233.75	85,074,134.02
363 - Storage battery equipment		145,039.46	439,363.10	652,632.38	936,405.26
364 - Poles, towers and fixtures	157,156,744.89	163,685,903.43	162,273,154.00	167,436,690.67	175,826,810.20
365 - Overhead conductors, devices	73,018,593.82	76,203,009.47	78,613,011.11	80,844,031.66	85,671,635.93
366 - Underground conduit	50,343,862.33	54,218,381.05	58,587,643.05	61,657,058.39	66,497,042.65
367 - Undergrnd conductors, devices	112,001,638.47	114,074,037.28	118,922,685.06	121,723,071.10	127,500,727.16
368 - Line transformers	129,046,380.96	132,931,525.01	136,207,142.98	138,287,495.02	140,855,920.90
369 - Services	56,403,665.41	61,658,984.63	67,434,727.07	72,113,221.66	78,796,018.00
370 - Meters	60,192,007.47	52,849,314.50	38,523,835.84	30,138,403.47	33,747,224.86
371 - Installs customer premise	13,028,268.26	12,968,119.72	12,814,076.08	12,678,574.52	12,335,680.51
373 - Street lighting,signal system	11,920,448.06	13,428,892.60	14,967,048.65	16,043,987.57	11,682,256.07
389 - Land and land rights	-	-	-	-	-
390 - Structures and improvements	26,035,659.16	29,372,643.42	31,813,851.66	33,018,717.96	35,322,809.28
391 - Office furniture, equipment	6,823,398.32	9,658,201.75	13,890,516.30	18,169,782.77	28,517,042.59
392 - Transportation equipment	10,880,296.11	11,927,447.14	14,289,130.78	15,487,709.24	17,156,713.48
393 - Stores equipment	396,435.16	389,717.76	406,394.25	428,080.02	432,149.50
394 - Tools, shop, garage equipment	1,984,714.68	2,054,965.31	2,174,906.32	2,331,546.77	2,557,334.00
395 - Laboratory equipment	2,963,402.25	3,142,928.80	3,357,401.40	3,575,078.01	3,788,528.57
396 - Power operated equipment	6,475,170.68	8,030,924.01	9,890,102.80	11,612,982.11	13,187,919.53
397 - Communication equipment	38,286,375.62	43,461,057.13	48,378,120.76	52,110,480.62	56,975,260.85
398 - Miscellaneous equipment	195,020.06	198,385.61	206,173.71	242,971.18	286,863.96
Subtotal 108/111 Elec Reserve	3,552,170,789.13	3,699,511,400.65	3,758,586,957.14	3,841,885,599 96	4,048,629,334.21
Retirement Work in Progress	(26,174,135.50)	(34,881,886.67)	(40,234,627.19)	(48,573,034 37)	(54,818,473.24)
Total Elec Reserve for Depr & Amort	3 525 996 653.63	3 664 629 513.98	3 718 352 329.95	3 793 312 565 59	3 993 810 860.97
Asset Retirement Costs Included Above					
317	8,654,188.50	9,285,443.21	21,767,936.06	25,800,465 08	41,490,317.19
326	-	576,992.87	1,153,986.07	1,586,730 54	2,123,578.03
347	1,478,204.63	1,730,662.55	1,983,120.46	2,172,463 87	2,424,921.74
Total ARO	10,132,393.13	11,593,098.63	24,905,042.59	29,559,659.49	46,038,816.96
Total Accum Depr Excl Asset Retirement Costs	3,515,864,260.50	3,653,036,415.35	3,693,447,287.36	3,763,752,906.10	3,947,772,044.01

SECTION 6
WORKING CAPITAL

Kansas City Power & Light Company
2018 RATE CASE - DIRECT
Kansas Jurisdiction
TY 9/30/17; K&M 6/30/18

Working Capital - Schedule 12

Line No.	Account No.	Description	Direct/Upd Balance	RB-82 TDC Adjustment	Adjusted Balance	Juris Factor #	Juris Allocator	Juris Adjusted Balance
	A	B			E	F	G	H
1	151	**FUEL INVENTORY - RB-74**						
2		Coal	54,607,361		54,607,361	E1	43.5895%	23,803,076
3		Oil	8,622,812		8,622,812	E1	43.5895%	3,758,641
4		Lime/Linestone	340,363		340,363	E1	43.5895%	148,363
5		Ammonia	413,955		413,955	E1	43.5895%	180,441
6		Powder Activated Carbon & Respond	246,698		246,698	E1	43.5895%	107,534
7		FOSSIL FUELS	64,231,189	0	64,231,189			27,998,054
8								
9	120	**NUCLEAR FUEL IN REACTOR - RB-75**						
10		Fuel w/o MO Gross AFUDC	247,095,785		247,095,785	E1	43.5895%	107,707,817
11		Less Accum Prov for Amort	(191,749,135)		(191,749,135)	E1	43.5895%	(83,582,489)
12		TOTAL NUCLEAR FUEL IN REACTOR	55,346,650	0	55,346,650			24,125,328
13								
14		**TOTAL FUEL INVENTORY**	119,577,839	0	119,577,839			**52,123,382**
15								
16	154 & 163	**MATERIALS & SUPPLIES - RB-72**						
17		Fossil Generation Related M&S	56,438,133		56,438,133	D1	47.0659%	26,563,115
18		Wolf Creek Related M&S	44,084,843		44,084,843	D1	47.0659%	20,748,928
19		T&D Related M&S - MO	1,084,505	0	1,084,505	100% MO	0.0000%	0
20		T&D Related M&S - KS	862,754	(31,893)	830,861	100% KS	100.0000%	830,861
21		T&D Related M&S - ALLOCATED	22,166,173	(819,397)	21,346,776	PTD	46.2712%	9,877,411
22		Wind Generation Related M&S	1,049,396		1,049,396	D1	47.0659%	493,908
23		Miscellaneous Other	0		0	PTD	46.2712%	0
24		**TOTAL MATERIALS & SUPPLIES**	125,685,804	(851,290)	124,834,514			**58,514,223**
25								
26	165	**PREPAYMENTS - RB-50 (excl GRT)**						
27		GRT Taxes	0		0	100% MO	0.0000%	0
28		General Insurance	3,423,976	(68,160)	3,355,816	PTD	46.2712%	1,552,776
29		Postage	97,714	(1,945)	95,769	C1	47.3951%	45,390
30		Other	6,863,061	(136,621)	6,726,440	D1	47.0659%	3,165,860
31		Wolf Creek General Insurance	2,818,582	(56,109)	2,762,473	D1	47.0659%	1,300,183
32		**TOTAL PREPAYMENTS**	13,203,333	(262,835)	12,940,498			**6,064,209**
33								
34		**WORKING CAPITAL, excl Cash**	258,466,976	(1,114,124)	257,352,852			**116,701,814**
35								
36		**CASH WORKING CAPITAL - Sch 8**						(38,547,174)
37								
38		**TOTAL WORKING CAPITAL**						78,154,640

Kansas City Power & Light Company
2018 RATE CASE - DIRECT
Kansas Jurisdiction
TY 9/30/17; K&M 6/30/18

Cash Working Capital - Schedule 8

Line No.	Account Description	W/P Ref	Jurisdictional Adjusted Test Year Expenses	Revenue Lag	Expense Lead	Net (Lead)/Lag (C) - (D)	Factor (Col E/365)	CWC Req (B) X (F)	
	A		B	C	D	E	F	G	
1	**Operations & Maintenance Expense**								
2	Gross Payroll excl Wolf Creek and Accrued Vac	Note (a)	53,587,377	28.57	14.44	14.13	0 0387	2,074,492	
3	Accrued Vacation	Note (a)	5,859,549	28.57	344.83	(316.26)	(0 8665)	(5,077,098)	
4	Wolf Creek Payroll	Note (a)	18,059,304	28.57	13.81	14.76	0 0404	730,289	
5	Nuclear Oper & Mtce, less fuel and payroll	Sch 9, ln 102 less A/C 518 and WC Payroll	19,553,559	28.57	13.81	14.76	0 0404	790,714	
6	Coal, Freight, Additives & Handling (non-labor)	Sch 9, see A/C 501	91,393,877	0	0	-	-	-	Note c
7	Purchased Gas	Sch 9, see A/C501/547	3,612,723	0	0	-	-	-	Note c
8	Purchased Oil, excl Wolf Creek	Sch 9, see A/C 501/547	1,609,376	0	0	-	-	-	Note c
9	Nuclear Fuel	Sch 9, A/C 518	13,455,196	0	0			-	Note c
10	Purchased Power	Sch 9, AC 555	63,030,987	0	0	-	-	-	Note c
11	Pension Expense	Sch 9, see A/C 926	22,153,184	28.57	51.74	(23.17)	(0 0635)	(1,406,272)	
12	OPEBs	Sch 9, see A/C 926	(298,316)	28.57	178.44	(149.87)	(0.4106)	122,489	
13	Cash Vouchers	calculation	90,643,901	28.57	39.15	(10.58)	(0 0290)	(2,627,431)	
14	Total Operation & Maintenance Expense	Sch 9	**382,660,716**					**(5,392,818)**	
15	**Taxes other than Income Taxes**								
16	FICA Taxes - Employer's	Sch 9, see A/C 708	5,872,632	28.57	14.42	14.15	0 0388	227,665	
17	City Franchise Taxes		24,216,955	28.57	47.67	(19.10)	(0 0523)	(1,267,243)	
18	Ad Valorem / Property Taxes	Sch 9, see A/C 708	46,558,678	28.57	200.42	(171.85)	(0.4708)	(21,920,846)	
19	Sales Taxes		33,663,114	28.57	24.24	4.33	0 0119	399,346	
20	Use Taxes		178,077	28.57	73.65	(45.08)	(0.1235)	(21,994)	
21	Total Taxes other than Income Taxes		**110,489,455**					**(22,583,072)**	
22	**Income Taxes**								
23	Current Income Taxes-Federal	Sch 11	22,773,569	28.57	45.63	(17.06)	(0 0467)	(1,064,430)	
24	Current Income Taxes-State	Sch 11	8 931 490	28.57	45.63	(17.06)	(0 0467)	(417 455)	
25	Total Income Taxes		**31,705,059**					**(1,481,886)**	
26	Misc Revenues incl Transmission for Others	Sch 9, line 23 (Note b)	**(4,185,959)**	28.57	36.88	(8.31)	(0 0228)	95,302	
27	Bulk Power Sales	Sch 9, AC 447 (Note b)	(50,552,593)	0	0	-	-	-	Note c
28	Interest Expense	Sch 11	**57,820,208**	28.57	86.55	(57.98)	(0.1588)	**(9,184,700)**	
29	**Total Cash Working Capital Requirement**		**527,936,885**					**(38,547,174)**	

Note a **Calculation of Jurisdictional Payroll for CWC**

	Total Company	Sal&Wg Allocation	Jurisdictional
Annualized Payroll (CS-50)	167,014,451	46.4069%	77,506,229
Less:			
Nuclear Payroll -Accts 517 -532 (CS-50)	38,915,126	46.4069%	18,059,304
Accrued Vacation	12,626,460	46.4069%	5,859,549
Gross Payroll excl Wolf Creek Prod and Accrued Vac	115,472,865		53,587,377

Note b Revenue and expense lags reflect a correction of the final Staff schedules supporting the order in 10-KCPE-415-RTS
Misc revenues were segregated from bulk power sales revenues. Bulk power sales revenues were given 0 day revenue and expense lags.

Note c ECA Components were given a 0 day lag, consistent with prior cases

KANSAS CITY POWER & LIGHT
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RB-74 Fuel Inventory
Account - 151 and 154

Fuel & Fuel Additive Inventory For Kansas Rate Base
Projected Value at June 30, 2018

Coal		Available (1)	Basemat (2)	Total Tons	Average Daily Burn (6)	Average Days Burn	Available Days Burn	KCPL Share	KCPL Share Tons	$/Ton (5)	Total Value KCPL Share	
Hawthorn	**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**
Iatan 1	**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**
Iatan 2	**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**
LaCygne BIT	**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**
LaCygne PRB	**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**
Montrose	**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**
TOTAL		2,594,000	239,101	2,833,101	30,337	93.4	85.5		1,878,545	$29.07	**$54,607,361**	

Oil		BBLS (4)		KCPL Share BBLs	$/BBL (5)	Total Value KCPL Share	$/gallon (5)	
Iatan	**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**
LaCygne	**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**
Montrose	**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**
Northeast (5)	**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**
Wolf Creek (5)	**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**
TOTAL		96,783		90,160.9	$95.64	**$8,622,812**	[redacted]	

Wolf Creek volume is already KCPL Share

Lime/Limestone			(4)		KCPL Share Tons	$/Ton (3)	Total Value KCPL Share	
TONS	Hawthorn	**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**
TONS	Iatan	**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**
LBS	LaCygne - lime **(6)**	**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**
TONS	LaCygne - limestone	**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**
	TOTAL		222,630		10,619.2	$32.05	**$340,363**	

Ammonia		LBS (4)		KCPL Share Tons	$/Ton (3)	Total Value KCPL Share	$/lb (5)	
Hawthorn 5	**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		**
Hawthorn 9 - premium	**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**
Iatan	**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		**
LaCygne	**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		**

Filed in Accordance with K.A.R. 21-1-231(c)(4)(F)(ii)

TOTAL	2,580,753		716.8	$577.50	**$413,955**	

Powder Activated Carbon		**LBS (4)**		**KCPL Share Tons**	**$/Ton (3)**	**Total Value KCPL Share**	$/lb (5)	
Hawthorn 5	**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**
Iatan 1	**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**
Iatan 2	**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**
LaCygne 1	**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**
LaCygne 2	**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**
Montrose	**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**
TOTAL		604,638		210.8	$1,018.78	**$214,788**		

Respond		**LBS (4)**		**KCPL Share Tons**	**$/LB (3)**	**Total Value KCPL Share**	
Montrose	**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**

TOTAL Fuel & Fuel Additive Inventory (KCPL share)	**$64,231,189**
September 2017 Acct 151100, 151300 & 154200 Balances	**$59,367,694**
RB-74 Fuel Inventories Adjustment	**$4,863,495**

Notes:

(1) Developed using UFIM or information from owner-operator
(2) Based on MIKON field work 2017. Basemat can be burned but with difficulty due to contamination.
(3) Forecast prices for June 2018 from SME, Analytics, or escalation of Jointly Owned Units
(4) Average of 12 months ended November 2017
(5) From Fuel Price workbook for June 2018 (commodity + freight)
(6) Utilizes the UFIM PROMOD run (11/20/2017 run) and the second run of MIDAs.

	Wolf Creek Barrels
Nov-16	6473.847
Dec-16	6455.226
Jan-17	6436.616
Feb-17	6489.312
Mar-17	6557.149
Apr-17	6536.189
May-17	6503.782
Jun-17	6487.074
Jul-17	6466.115
Aug-17	6466.115
Sep-17	5578.855
Oct-17	5527.961
Average	6331.520083

KANSAS CITY POWER & LIGHT
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RB-75 Nuclear Fuel Inventory
Account - 120XXX

debit (credit)

DR/(CR)		ACCOUNT & DESCRIPTION					
		120220 Nucl Fuel Stock-Mat & Assem	120330 Nucl Fuel In Reactor	120440 Nucl Fuel Spent Fuel	Total Nucl Fuel	120561 Nucl Fuel Amortz Provision	
1 January-2017	TB	-	101,676,697	132,224,591	233,901,288	(174,869,207)	
2 February-2017	TB	-	101,676,697	132,224,591	233,901,288	(177,360,336)	
3 March-2017	TB	-	101,676,697	132,224,591	233,901,288	(180,116,456)	
4 April-2017	TB	-	101,676,697	132,224,591	233,901,288	(182,767,900)	
5 May-2017	TB	-	101,676,697	132,224,591	233,901,288	(185,527,105)	
6 June-2017	TB	-	101,676,697	132,224,591	233,901,288	(187,989,730)	
7 July-2017	TB	-	101,676,697	132,224,591	233,901,288	(190,875,926)	
8 August-2017	TB	-	101,676,697	132,224,591	233,901,288	(193,575,346)	**Test Period**
9 September-2017	TB	-	101,676,697	132,224,591	233,901,288	(196,187,786)	37,713,502
10 October-2017	TB	8,083,160	101,676,697	132,224,591	241,984,448	(198,884,686)	
11 November-2017	TB	39,557,842	101,676,697	132,224,591	273,459,130	(201,500,955)	
12 December-2017	TB	40,204,203	101,676,697	132,224,591	274,105,491	(204,200,667)	
13 January-2018	TB	40,204,203	101,676,697	132,224,591	274,105,491	(206,900,362)	
14 February-2018	Projections	40,204,203	101,676,697	132,224,591	274,105,491	(209,276,746) *	
15 March-2018	Projections	40,204,203	101,676,697	132,224,591	274,105,491	(211,840,822) *	
16 April-2018	Projections	40,204,203	101,676,697	132,224,591	274,105,491	(211,840,822) *	
17 May-2018	Projections	1,827,149	93,792,018	132,701,583	228,320,750	(167,639,857) *	
18 June-2018	Projections	1,827,149	93,792,018	132,701,583	228,320,750	(170,129,714) *	**18 mth Avg**
18 Month Average		14,017,573	100,800,622	132,277,590	247,095,785	(191,749,135)	55,346,650
					RB-75	RB-75	Total RB-75
Adjustment From Test Year		14,017,573	(876,075)	52,999	**13,194,497**	**4,438,651**	**17,633,148**
Test Period vs 18 mth avg.							

* Projections February 2018 through June 2018 were provided by WCNOC.

KANSAS CITY POWER & LIGHT
2018 Rate Case - KCP&L - KS Direct
TY 9/30/17; Update 6/30/18

RB-72 Materials & Supplies Inventory
Account - 154XXX & 163XXX

Account	Description		13 MO AVG (except for starred accts)	Fossil Fuel Generating Stations	Wolf Creek	T&D Missouri	T&D Kansas	T&D Allocated	Wind	Other	Check Total
154000	Plant Material And Supplies										-
	M&S Substation Spare Parts	*	3,794,539					3,794,539			3,794,539
	M&S F&M Central Stores	*	13,526,926			318,473		13,208,453			13,526,926
	M&S Northland Service Center		318,473			318,473					318,473
	M&S Dodson Service Center		116,430			116,430					116,430
	M&S Brunswick Service Center		195,909			195,909					195,909
	M&S Southland Service Center		210,961				210,961				210,961
	M&S Johnson Co Service Center	*	248,156				248,156				248,156
	M&S Paola Service Center		283,815				283,815				283,815
	M&S Ottawa Service Center		63,963				63,963				63,963
	M&S CT Maintenance	*	3,544,969	3,544,969							3,544,969
	M&S Hawthorn Power Station	*	14,430,366	14,430,366							14,430,366
	M&S Montrose Power Station	*	7,145,556	7,145,556							7,145,556
	M&S Spearville Wind	*	1,049,396						1,049,396		1,049,396
154100	MandS Deposits		935,113					935,113			935,113
154200	Fuel Additives	*	760,864	760,864							760,864
154400	Plant M and S Transfers		26,369	26,369							26,369
154550	MandS Iatan Power Station	*	28,257,086	28,257,086							28,257,086
154553	MandS Iatan EDE	*	(3,390,850)	(3,390,850)							(3,390,850)
154554	MandS Iatan MJMEUC	*	(1,859,316)	(1,859,316)							(1,859,316)
154555	MandS Iatan GMO	*	(5,086,275)	(5,086,275)							(5,086,275)
154556	MandS Iatan KEPCO	*	(556,665)	(556,665)							(556,665)
154570	MandS LaCygne Power Station	*	24,495,087	24,495,087							24,495,087
154576	MandS LaCygne WR	*	(12,247,544)	(12,247,544)							(12,247,544)
154581	MandS Wolf Creek Station	*	43,706,724		43,706,724						43,706,724
154610	MandS Veh Fuel Warrensburg		7,937			7,937					7,937
154620	MandS Veh Fuel FandM		51,585			51,585					51,585
154630	MandS Veh Fuel Northland		20,323			20,323					20,323
154640	MandS Veh Fuel Dodson		40,645			40,645					40,645
154650	MandS Veh Fuel Johnson County		34,144				34,144				34,144
154660	MandS Veh Fuel St Joe		8,074			8,074					8,074
154661	MandS Veh Fuel Lees Summit		1,892			1,892					1,892
154662	MandS Veh Fuel Belton		4,764			4,764					4,764
154670	MandS Veh Fuel Southland		21,715				21,715				21,715
163020	Stores Expense Undistributed		(1,608,834)	(1,608,834)							(1,608,834)
163100	Stores Exp Undist Wolf Crk		378,119		378,119						378,119
163200	Stores Exp Undis Production		3,288,184	3,288,184							3,288,184
163300	Stores Exp Undis T and D		4,228,068					4,228,068			4,228,068
	TOTAL M&S		126 446 668	57 198 997	44 084 843	1 084 505	862 754	22 166 173	1 049 396	-	126 446 668
Less Fuel Additives Incl in Fuel Inv. Consistent with Staff											
154200	Fuel Additives		(760,864)	(760,864)							(760,864)
	ADJUSTED TOTAL M&S		125 685 804	56 438 133	44 084 843	1 084 505	862 754	22 166 173	1 049 396	-	125 685 804
				RB-72	RB-72	RB-72	RB-72	RB-72	RB-72	RB-72	RB-72

* Used EOM balance

Filed in Accordance with K.A.R. 21-1-231(c)(4)(F)(ii)

KANSAS CITY POWER & LIGHT
2018 Rate Case - KCP&L - KS Direct
TY 9/30/17 Update 6/30/18

RB-50 Prepayments - 13 mo Average
Account - 165XXX

Computation of 13-Month Average for Prepayments

	165001	165004	165008	165011			
	Prepaid Insurance	Prepaid Postage	Prepayments-Other	Prepayments-Gen Exp-WC	Exclude: WC Prepaid Premiums on Life Ins	Adj Prepayments-Gen Exp-WC	
Sept 2016	2,309,201	189,971	7,521,412	2,195,795	48,283	2,147,512	
Oct 2016	2,987,457	163,286	7,183,048	2,375,598	42,247	2,333,351	
Nov 2016	5,344,541	141,863	5,698,507	1,965,272	36,212	1,929,060	
Dec 2016	4,772,988	104,896	5,303,938	1,965,874	30,177	1,935,697	
Jan 2017	3,963,592	103,717	5,682,940	3,051,649	24,141	3,027,508	
Feb 2017	3,391,161	86,850	6,696,885	2,544,057	18,106	2,525,951	
March 2017	2,818,731	64,421	5,586,442	3,438,669	12,071	3,426,598	
April 2017	2,246,300	58,592	6,287,408	4,087,559	6,035	4,081,524	
May 2017	4,387,173	46,844	7,796,585	3,307,662	0	3,307,662	
June 2017	3,815,674	71,466	6,750,744	3,736,593	66,148	3,670,445	
July 2017	3,244,174	77,115	8,451,649	3,641,586	60,134	3,581,452	
August 2017	2,946,084	65,862	8,225,953	2,803,130	54,121	2,749,009	
September 2017	2,284,618	95,401	8,034,287	1,973,907	48,107	1,925,800	
							Total
13-Month Average @ September 2017	**3,423,976**	**97,714**	**6,863,061**	2,852,873	34,291	**2,818,582**	**13,203,334**
	RB-50	**RB-50**	**RB-50**			**RB-50**	**RB-50**

Note: Prepayments for Rate Base exclude gross receipts tax prepayments (Acct 165201 and 165202) as well as CLEAResult Rebate prepayments (Acct 165100) CLEAResult Rebates are prefunded in an account for the payment of the MO Juris MEEIA rebates that are disbursed by the program vendor which in turn issues a check to customers for incentive rebates. The expense is recorded to 908500 which is eliminated in CS-98 and recovered through the MO Rider.

SECTION 7
CAPITAL AND COST OF MONEY

Filed in Accordance with K.A.R. 21-1-231(c)(4)(G)(i)

Kansas City Power & Light Company
Projected Capitalization
June 30, 2018 (projection)
($ in 000's)

CAPITAL COMPONENT		AMOUNT		PERCENT	REQUIRED RETURN	WEIGHTED RETURN
Long-Term Debt (Note 1)	**	$ [redacted]	**	50.25%	4.9409%	2.4826%
Common Equity	**	[redacted]	**	49.75%	9.8500%	4.9009%
Total Capitalization	**	$ [redacted]	**	100.00%		7.3835%

Note 1: Excludes unamortizaed debt expenses and discounts. Includes current maturities of long-term debt

KANSAS CITY POWER & LIGHT COMPANY
Capitalization
September 30, 2017
($ in 000's)

CAPITAL COMPONENT	AMOUNT	PERCENT	REQUIRED RETURN	WEIGHTED RETURN
KCP&L Long-Term Debt (Note 1)	$2,599,380	50.63%	5.3424%	2.7047%
KCP&L Common Equity	2,535,026	49.37%	9.3000%	4.5917%
Total KCP&L Capital	$5,134,406	100.00%		7.2964%

Note 1: Excludes unamortizaed debt expenses and discounts. Includes current maturities of long-term debt

KANSAS CITY POWER & LIGHT COMPANY
Weighted Average Cost of Long-Term Debt Capital
June 30, 2018

Line	Issue	(a) Initial Offering	(b) Date of Offering	(c) Date of Maturity	(d) Price to Public	(e) Original Discount (Premium)	(f) Underwriting & Issuance Expense	(g) Net Proceeds to Company	(h) Cost to Company	(i) Long-term Debt Capital Outstanding	(j) Annual Cost of Long-term Debt Capital
	KANSAS CITY POWER & LIGHT ONLY										
	Pledged General Mortgage Bonds										
1	MATES Series 1993-A	$40,000,000	12/7/1993	12/1/2023	$40,000,000		$957,337	$39,042,663	3.035%	$40,000,000	$1,214,080
2	MATES Series 1993-B	$39,480,000	12/7/1993	12/1/2023	$39,480,000		$364,531	$39,115,469	3.037%	$39,480,000	$1,198,957
3	EIRR La Cygne 2005 Series - 4.65% Coupon	$21,940,000	2/23/1994	9/1/2035	$21,940,000			$21,940,000	4.650%	$21,940,000	$1,020,210
4	Mortgage Bonds Series 2009A - 7.15%	$400,000,000	3/24/2009	4/1/2019	$400,000,000	$432,000	$4,023,316	$395,544,684	8.591%	$400,000,000	$29,044,879
	Unsecured Notes										
5	Senior Notes Due 2047 - 4.20% Coupon	$300,000,000	6/15/2017	6/15/2047	$300,000,000	$813,000	$2,869,890	$296,317,110	4.242%	$300,000,000	$12,726,831
6	Senior Notes Due 2035 - 6.05% Coupon	$250,000,000	11/17/2005	11/15/2035	$250,000,000	$1,505,000	$2,443,109	$246,051,891	5.944%	$250,000,000	$15,256,435
7	Senior Notes Due 2041 - 5.30% Coupon	$400,000,000	9/20/2011	10/1/2041	$400,000,000	$2,568,000	$3,876,569	$393,555,431	5.354%	$400,000,000	$21,415,066
8	Senior Notes Due 2023 - 3.15% Coupon	$300,000,000	3/14/2013	3/15/2023	$300,000,000	$282,000	$2,339,941	$297,378,059	3.237%	$300,000,000	$9,710,189
9	Notes Due 2038 - 4.00% Coupon	$300,000,000	3/1/2018	3/1/2028	$300,000,000		$2,625,000	$297,375,000	4.044%	$300,000,000	$12,131,250
10	Senior Notes Due 2025 - 3.65% Coupon	$350,000,000	8/13/2015	8/15/2025	$350,000,000	$1,246,000	$2,925,379	$345,828,621	3.769%	$350,000,000	$13,191,973
	Environmental Improvement Revenue Refunding Bonds										
11	2005 Series Due 2035 - 4.65% Coupon	$50,000,000	9/1/05	9/1/2035	$50,000,000			$50,000,000	4.650%	$50,000,000	$2,325,000
12	2007 Series A Due 2035	$73,250,000	9/19/07	9/1/2035	$73,250,000		$130,278	$73,119,722	2.709%	$73,250,000	$1,984,401
13	2007 Series B Due 2035	$73,250,000	9/19/07	9/1/2035	$73,250,000		$130,278	$73,119,722	2.709%	$73,250,000	$1,984,401
14	2008 Series Due 2038	$23,400,000	5/28/08	5/1/2038	$23,400,000			$23,400,000	2.912%	$23,400,000	$681,343
	Other Long-Term Debt										
15	Unamortized Discount on Senior Notes										
16	Unamortized Debt Expense										
17	Loss/(Gain) on Reacquired Debt										$ 500,771
18	Hedging Expense/(Gain)										$ 4,922,884
19	Tax-exempt Debt Repurchased (lines 4 and 12)								4.650%	($71,940,000)	($3,345,210)
20	**Total KCP&L Long-Term Debt Capital**				**June 30, 2018**					$2,549,380,000	$125,963,461
	Maturity Value of Long-Term Debt										
21	**KCP&L Weighted Avg. Cost of Long-Term Debt Capital**				**June 30, 2018**			4.9409%			

KANSAS CITY POWER & LIGHT COMPANY, GREAT PLAINS ENERGY and GMO
Weighted Average Cost of Long-Term Debt Capital
September 30, 2017

Line	Issue	(a) Initial Offering	(b) Date of Offering	(c) Date of Maturity	(d) Price to Public	(e) Original Discount (Premium)	(f) Underwriting & Issuance Expense	(g) Net Proceeds to Company	(h) Cost to Company	(i) Long-term Debt Capital Outstanding	() Annual Cost of Long-term Debt Capital
	KANSAS CITY POWER & LIGHT ONLY										
	Pledged General Mortgage Bonds										
1	MATES Series 1993-A	$40,000,000	12/7/1993	12/1/2023	$40,000,000		$957,337	$39,042,663	3.035%	$40,000,000	$1,214,080
2	MATES Series 1993-B	$39,480,000	12/7/1993	12/1/2023	$39,480,000		$364,531	$39,115,469	3.037%	$39,480,000	$1,198,957
3	EIRR La Cygne 2005 Series - 4.65% Coupon	$21,940,000	2/23/1994	9/1/2035	$21,940,000			$21,940,000	4.650%	$21,940,000	$1,020,210
4	Mortgage Bonds Series 2009A - 7.15%	$400,000,000	3/24/2009	4/1/2019	$400,000,000	$432,000	$4,023,316	$395,544,684	7.261%	$400,000,000	$29,044,879
	Unsecured Notes										
5	Senior Notes Due 2047 - 4.20% Coupon	$300,000,000	6/15/2017	6/15/2047	$300,000,000	$813,000	$2,659,675	$296,527,325	4.241%	$300,000,000	$12,722,818
6	Senior Notes Due 2035 - 6.05% Coupon	$250,000,000	11/17/2005	11/15/2035	$250,000,000	$1,505,000	$2,443,109	$246,051,891	6.103%	$250,000,000	$15,256,435
7	Senior Notes Due 2018 - 6.375% Coupon	$350,000,000	3/6/2008	3/1/2018	$350,000,000		$2,566,730	$347,433,270	6.449%	$350,000,000	$22,570,083
8	Senior Notes Due 2041 - 5.30% Coupon	$400,000,000	9/20/2011	10/1/2041	$400,000,000	$2,568,000	$3,876,569	$393,555,431	5.354%	$400,000,000	$21,415,066
9	Senior Notes Due 2023 - 3.15% Coupon	$300,000,000	3/14/2013	3/15/2023	$300,000,000	$282,000	$2,339,941	$297,378,059	3.237%	$300,000,000	$9,710,189
10	Senior Notes Due 2023 - 3.65% Coupon	$350,000,000	8/13/2015	8/15/2025	$350,000,000	$1,246,000	$2,925,379	$345,828,621	3.769%	$350,000,000	$13,191,670
	Environmental Improvement Revenue Refunding Bonds										
11	2005 Series Due 2035 - 4.65% Coupon	$50,000,000	9/1/05	9/1/2035	$50,000,000			$50,000,000	4.650%	$50,000,000	$2,325,000
12	2007 Series A Due 2035	$73,250,000	9/19/07	9/1/2035	$73,250,000		$130,278	$73,119,722	1.514%	$73,250,000	$1,109,182
13	2007 Series B Due 2035	$73,250,000	9/19/07	9/1/2035	$73,250,000		$130,278	$73,119,722	1.514%	$73,250,000	$1,109,182
14	2008 Series Due 2038	$23,400,000	5/28/08	5/1/2038	$23,400,000			$23,400,000	2.912%	$23,400,000	$681,343
	Other Long-Term Debt										
15	Unamortized Discount on Senior Notes										
16	Unamortized Debt Expense						$151,420,000				
17	Loss/(Gain) on Reacquired Debt						$79,480,000				$ 555,423
18	Hedging Expense/(Gain)										$ 9,090,359
18	Tax-exempt Debt Repurchased (lines 4 and 12)						79480000			($71,940,000)	($3,345,210)
19	**Total KCP&L Long-Term Debt Capital**									$2,599,380,000	$138,869,666
	Maturity Value of Long-Term Debt										
20	**KCP&L Weighted Avg. Cost of Long-Term Debt Capital**				9/30/2017			5.342%			

The Cost of Preferred Stock Capital is not available as no preferred stock currently exists.

Kansas City Power & Light Company
Historical Interest Coverage [(1)]

Funds from Operations Interest Coverage

			A	B	C	D	E
						12-MOS ENDED PRIOR TO TEST YEAR	12-MOS ENDED TEST YEAR
			12/31/2013 (millions)	12/31/2014 (millions)	12/31/2015 (millions)	9/30/2016 (millions)	9/30/2017 (millions)
Numerator	1	Operating Income	362.5	350.1	364.0	496.3	436.3
	2	Depreciation and Amortization	198.3	213.9	235.7	244.8	263.3
	3	EBITDA	560.8	564.0	599.7	741.1	699.6
	4	Interest Expense	(125.3)	(124.1)	(135.6)	(140.1)	(140.0)
	5	Current Income Taxes	1.0	(11.7)	(22.1)	(41.8)	(49.4)
	6	Operating Leases	6.4	6.0	5.4	5.4	5.1
	7	Capitalized Interest	(10.6)	(11.1)	(3.9)	(4.7)	(6.0)
	8	Share Based Compensation Expense	4.0	6.9	2.6	2.0	3.6
	9	Asset Retirement Obligations	3.0	3.2	13.8	13.8	(0.5)
	10	Amortization of Nuclear Fuel	22.8	26.1	26.8	30.8	28.3
	11	Total adjustments	(98.7)	(104.7)	(113.0)	(134.6)	(158.8)
	12	**Total Funds from operations (FFO)**	**462.1**	**459.3**	**486.7**	**606.5**	**540.8**
	13	Reported interest expense	125.3	124.1	135.6	140.1	140.0
	14	Interest expense adjustments	26.7	27.5	22.3	23.1	25.1
	15	**Total Numerator**	**614.1**	**610.9**	**644.6**	**769.7**	**705.9**
Denominator	16	Reported interest expense	125.3	124.1	135.6	140.1	140.0
	17	Operating leases	7.6	7.2	6.9	6.9	6.8
	18	Capitalized interest	10.6	11.1	3.9	4.7	6.0
	19	Asset retirement obligations	8.5	9.2	11.5	11.5	12.3
	20	Total adjustments	26.7	27.5	22.3	23.1	25.1
	21	**Total Denominator**	**152.0**	**151.6**	**157.9**	**163.2**	**165.1**
	22	**FFO Interest Coverage Ratio**	**4.0**	**4.0**	**4.1**	**4.7**	**4.3**

Note:

[(1)] As KCP&L is not required to calculate interest coverage ratios with respect to its bond and indenture requirements, the ratios above have been formatted using Standard & Poor's "Funds From Operations (FFO) Interest Coverage" ratio methodology The funds from operations interest coverage is consistent with the ratio calculations and adjustment methodology utilized by S&P for the 2017 year end credit ratio calculations

Filed in Accordance with K.A.R. 21-1-231(c)(4)(G)(iv)

GREAT PLAINS ENERGY
Capitalization
September 30, 2017
($ in 000's)

CAPITAL COMPONENT	AMOUNT	PERCENT
GPE Long-Term Debt (Note 1)	$3,682,230	41.98%
GPE Common Equity	5,088,915	58.02%
Total KCP&L Capital	$8,771,145	100.00%

Note 1: Excludes unamortizaed debt expenses and discounts. Includes current maturities of long-term debt

SECTION 8
FINANCIAL AND OPERATING DATA

Kansas City Power & Light Company
SECTION 8 FINANCIAL AND OPERATING DATA
Balance Sheet by Primary Account
Source - FERC Form 1, pages 110-113

Primary Account	Description	Calendar Year Ending 2013	2014	2015	Test Year Ending 12 months ended Sep-16	12 months ended Sep-17
COMPARATIVE BALANCE SHEET - ASSETS & OTHER DEBITS						
debit (credit)						
	UTILITY PLANT					
101	Utility Plant in Service	8,274,894,370	8,737,315,015	9,640,330,292	9,768,778,264	10,120,806,366
107	Construction Work in Progress	665,123,110	791,235,220	246,669,494	306,553,566	310,894,428
108	Accumulated Prov for Depreciation	(3,525,996,190)	(3,664,629,514)	(3,718,352,330)	(3,793,312,565)	(3,993,810,861)
111	Accumulated Prov for Amortization	-				
120.1	Nuclear Fuel in Process	7,006,100	4,107,977	20,274,424	40,856,211	27,179,229
120.2	Nuclear Fuel in Stock	-	45,373,274	-		-
120.3	Nuclear Fuel in Reactor	102,612,267	102,612,267	106,728,421	106,728,421	101,676,697
120.4	Spent Nuclear Fuel	114,553,030	114,553,030	133,767,308	133,767,308	132,224,591
120.5	Accum Prov for Amort of Nuclear Fuel	(161,365,463)	(187,450,423)	(192,501,678)	(214,861,521)	(196,187,786)
	Net Utility Plant	5,476,827,224	5,943,116,846	6,236,915,931	6,348,509,684	6,502,782,664
	OTHER PROPERTY AND INVESTMENTS					
121	Nonutility Property	6,643,573	4,876,950	6,879,353	6,484,783	8,576,567
122	Accumulated Prov for Depr/Amort-Nonutility Prop	(2,898,230)	(1,349,611)	(1,664,566)	(1,572,914)	(2,395,415)
123.1	Investment in Subsidiary Companies	17,907,332	23,122,773	28,240,268	32,906,599	38,195,521
124	Other Investments	1,842,337	1,939,134	2,005,636	1,636,053	1,716,709
128	Other Special Funds	183,948,352	198,962,936	200,671,659	218,335,848	247,461,940
176	Long-term Portion of Derivative Assets - Hedges	-	-	-	-	-
	Total Other Property and Investments	207,443,364	227,552,182	236,132,350	257,790,369	293,555,322
	CURRENT AND ACCRUED ASSETS					
131	Cash	3,964,592	2,691,895	2,227,059	5,611,206	4,547,428
132-134	Special Deposits	709,302	608,583	539,702	1,420,602	289,223
135	Working Funds	4,700	7,050	7,050	7,050	9,400
136	Temporary Cash Investments					
141	Notes Receivable					
142	Customer Accounts Receivable	403,632	411,287		-	-
143	Other Accounts Receivable	77,918,171	79,694,266	69,442,725	44,340,937	40,720,631
144	Accum Prov for Uncollectible Accounts Rec				-	-
145	Notes Receivable from Associated Companies	47,479,501	44,404,517	61,814,267	150,042,429	114,452,740
146	Accounts Receivable from Associated Co	36,374,392	50,392,495	36,827,274	31,670,226	31,617,794
151	Fuel Stock	50,241,301	58,731,308	83,473,295	70,690,694	61,967,840
154	Plant Materials and Operating Supplies	97,199,305	105,595,307	108,551,713	111,366,172	120,106,906
158.1 & 158.2	Allowances	52,733	63,845	66,518	116,737	135,102
163	Undistributed Stores Expense	11,801,877	4,552,347	6,081,711	7,070,555	6,024,457
165	Prepayments	11,355,210	14,429,748	13,082,494	12,717,118	14,191,622
171	Interest and Dividends Receivable	-				
172	Rents Receivable	-	71,810	200	1,349,509	1,532,556
174	Misc Current and Accrued Assets	59,504,385	85,166,307	111,476,616	25,607,694	21,742,128
176	Derivative Instrument Assets - Hedges	-	3,065,175		398,630	816,023
176	Less Long-Term Portion of Derivative Instrument Assets - Hedges	1,094,850				
	Total Current and Accrued Assets	398,103,951	449,885,940	493,590,624	462,409,559	418,153,853
	DEFERRED DEBITS					
181	Unamortized Debt Expense	19,687,383	16,051,537	12,839,845	11,657,006	12,877,767
182.3	Other Regulatory Assets	704,655,323	831,622,973	803,634,926	796,053,282	817,332,313
183	Preliminary Survey and Investigation	-	-	108,276	233,148	250,408
184	Clearing Accounts	143,585	639,661	(162,818)	(40,616)	178,186
185	Temporary Facilities	-	-	-	-	-
186	Miscellaneous Deferred Debits	5,548,701	7,268,498	10,131,410	13,710,241	30,569,888
188	Research, Devel. And Demonstration Expend.	-				
189	Unamortized Loss on Reacquired Debt	7,065,452	8,114,042	11,306,977	10,299,906	8,994,327
190	Accumulated Deferred income Taxes	542,684,921	581,651,505	736,010,243	731,879,670	739,754,927
	Total Deferred Debits	1,279,785,365	1,445,348,216	1,573,868,859	1,563,792,637	1,609,957,816
	Total Assets and Other Debits	7,362,159,904	8,065,903,184	8,540,507,764	8,632,502,245	8,824,449,657

Kansas City Power & Light Company
SECTION 8 FINANCIAL AND OPERATING DATA
Balance Sheet by Primary Account
Source - FERC Form 1, pages 110-113

Primary Account	Description	Calendar Year Ending 2013	2014	2015	Test Year Ending 12 months ended Sep-16	12 months ended Sep-17
COMPARATIVE BALANCE SHEET - LIABILITIES & OTHER CREDITS						
(debit) credit						
	PROPR ETARY CAPITAL					
201	Capital Stock issued	487,041,247	487,041,247	487,041,247	487,041,247	487,041,247
211	Miscellaneous Paid In Capital	1,076,114,704	1,076,114,704	1,076,114,704	1,076,114,704	1,076,114,704
216	Unappropriated Retained Earnings	616,151,777	701,346,037	849,006,104	975,493,506	937,137,384
216.1	Unappropriated Undistributed Subsidiary Retained Earnings	14,907,332	20,122,774	25,240,268	29,906,599	35,195,522
219	Accumulated Other Comprehensive Income	(20,385,860)	(15,031,049)	(9,674,445)	(5,656,992)	(463,180)
	Total Proprietary Capital	2,173,829,200	2,269,593,713	2,427,727,878	2,562,899,064	2,535,025,677
	LONG TERM DEBT					
221	Bonds	2,316,302,000	2,316,302,000	2,652,320,000	2,652,320,000	2,671,320,000
222	Reaquired Bonds	-		(71,940,000)	(71,940,000)	(71,940,000)
223	Advances from Associated Companies	-				
224	Other Long Term Debt	-				
226	Unamortized Discount on Long Trm Debt	(4,097,129)	(3,849,502)	(4,801,986)	(4,523,269)	(4,965,883)
	Total Long Term Debt	2,312,204,871	2,312,452,498	2,575,578,014	2,575,856,731	2,594,414,117
	OTHER NON-CURRENT LIABILITIES					
227	Obligations Under Capital Leases	1,847,128	1,768,855	1,684,170	1,616,134	1,518,937
228.2	Accumulated Provision for Injuries & Damages	2,967,390	3,054,419	5,413,473	5,460,219	16,735,082
228.3	Accumulated Provision for Pensions & Benefits	339,946,839	485,412,219	433,419,064	445,733,386	473,096,170
228.4	Accumulated Misc Operating Provisions	-				
230	Asset Retirement Obligations	141,650,829	177,682,355	239,296,606	246,712,859	261,164,723
	Other Non-Current Liabilities	486,412,186	667,917,848	679,813,313	699,522,598	752,514,912
	CURRENT AND ACCRUED LIABILITIES					
231	Notes Payable	93,200,000	358,300,000	180,300,000	-	72,000,000
232	Accounts Payable	257,086,419	309,871,672	268,938,994	190,858,548	170,417,211
233	Notes Payable to Associated Companies	200,000	12,600,000			
234	Accounts Payable to Associated Companies	759	256	7,876	18,755	20,332
235	Customer Deposits	4,984,730	5,591,577	5,854,869	6,431,555	6,177,765
236	Taxes Accrued	23,802,742	23,613,565	25,638,716	125,331,604	136,824,075
237	Interest Accrued	29,067,759	29,014,194	32,353,852	41,297,006	40,546,992
241	Tax Collections Payable	6,808,057	6,852,867	7,171,388	10,098,841	9,699,183
242	Miscellaneous Current & Accrued Liabilities	32,919,812	31,863,458	32,275,464	33,700,439	32,482,720
243	Obligations Under Capital Leases - Current	72,346	78,273	84,685	89,837	97,197
245	Dirivative Instument Liabilities - Hedges	-	-	383,005	-	-
	Total Current and Accrued Liabilities	448,142,624	777,785,862	553,008,849	407,826,585	468,265,474
	DEFERRED CREDITS					
252	Customer advances for Construction	1,529,892	3,240,056	3,497,486	3,428,866	4,028,876
253	Other Deferred Credits	84,125,155	51,038,540	50,920,802	50,201,653	50,168,223
254	Other Regulatory Liabilities	266,862,899	268,805,362	260,072,222	270,760,780	294,058,522
255	Accumulated Deferred Investment Tax Credits	125,326,721	124,342,857	123,826,602	123,039,806	121,990,746
257	Unamortized Gain on Reaquired Debt	-	-	-	-	-
281	Accum Deferred Income Taxes - Accel Amort	50,794,678	65,590,634	81,881,607	93,312,081	95,718,151
282	Accum Deferred Income Taxes - Other Property	1,219,443,093	1,347,945,185	1,588,620,338	1,660,138,877	1,705,847,566
283	Accum Deferred Income Taxes - Other	193,488,585	177,190,629	195,560,653	185,515,205	202,417,395
	Total Deferred Credits	1,941,571,023	2,038,153,263	2,304,379,710	2,386,397,267	2,474,229,478
	Total Liabilities and Other Credits	7,362,159,904	8,065,903,184	8,540,507,764	8,632,502,245	8,824,449,657

Kansas City Power & Light Company
SECTION 8 FINANCIAL AND OPERATING DATA
Comparative Income and Retained Earnings Statements
Source -Calendar Year - FERC Form 1, pages 114-117 and 118-119.
Source -Test Year -Test Yr Query

Primary Account	Description	Calendar Year Ending 2013	2014	2015	Test Year Ending 12 months ended Sep-16	12 months ended Sep-17
Operating Revenues (debit) credit						
400	Operating Revenues	1,671,422,009	1,730,764,278	1,713,813,202	1,873,809,140	1,875,647,405
Operating Expenses debit (credit)						
401	Operation Expenses	827,524,776	872,294,631	824,430,173	827,062,350	836,929,963
402	Maintenance Expenses	122,903,083	128,998,157	117,549,417	119,674,732	121,484,421
403	Depreciation Expenses	180,092,968	191,125,504	214,206,624	226,328,778	241,455,312
404	Amort of Limited Term Plant	1,569,688	1,704,936	1,832,008	1,887,034	1,908,936
405	Amort of Other Electric Plant	17,467,130	22,493,792	28,308,087	28,391,769	36,426,834
407.3	Regulatory Debits			960,389	3,221,206	940,556
407.4	Regulatory Credits	(9,347,576)	(10,605,004)	(20,151,045)	(23,928,465)	(30,269,110)
408.1	Taxes Other Than Income Taxes	152,032,438	159,087,760	163,528,029	175,416,892	180,815,367
409.1	Income Taxes	(6,318,170)	(7,099,455)	(17,380,041)	(23,298,508)	69,211,672
410.1	Provision for Defered Income Taxes	95,369,455	168,362,689	258,691,354	168,678,627	72,771,998
411.1	Provision for Deferred Income Taxes-Credit	(3,339,040)	(79,727,930)	(159,344,783)	(15,368,345)	(20,468,407)
411.4	Investment Tax Credit Adj - Net	(751,440)	(897,718)	(941,951)	(962,914)	(962,914)
411.7	Losses from Disposition of Utility Plant	-				
411.8	Gains from Disposition of Allowances	-				
411.10	Accretion Expense	8,479,294	9,144,298	11,496,947	12,051,314	13,374,942
	Total Operating Expenses	1,385,682,606	1,454,881,660	1,423,185,208	1,499,154,470	1,523,619,570
	Net Utility Operating Income	285,739,403	275,882,618	290,627,994	374,654,670	352,027,835
Other Income and Deductions (debit) credit						
417	Revenues from Nonutility Operations	3,858,798	6,128,673	6,297,688	6,368,491	5,485,957
417.1	Expenses of Nonutility Operations	(1,060,571)	(2,625,888)	(2,892,041)	(2,087,318)	(2,301,355)
418	Nonoperating Rental Income	(143,106)	(271,829)	118,800	145,749	160,075
418.1	Equity in Earnings of Subsidiary Companies	4,232,304	5,215,442	5,117,494	5,842,513	5,288,923
419	Interest and Dividend Income	396,129	451,495	416,775	940,159	2,825,548
419.1	Allow for Other Funds Used During Const	14,136,970	16,013,394	3,768,681	4,950,024	5,962,132
421	Miscellaneous Nonoperating Income	696,210	740,953	729,179	714,631	687,989
421.1	Gain on Disposition of Property	-	1,344,912	150,735	43,144	16,025
421.2	Loss on Disposition of Property	(23,269)	(75,327)	(64,407)	(65,352)	(87,333)
426.1	Donations	(2,910,640)	(3,339,940)	(2,207,469)	(1,910,976)	(3,981,850)
426.2	Life Insurance	(684,260)	(730,564)	(602,359)	(1,018,159)	(609,083)
426.3	Penalties	(583)	(67,102)	(240,142)	(269,040)	(12,239)
426.4	Certain Civic, Political & Related Activities	(563,895)	(881,640)	(810,153)	(1,135,963)	(1,151,326)
426.5	Other Deductions	(18,348,206)	(20,556,045)	(20,369,172)	(22,289,327)	(50,893,141)
408.2	Taxes Other than Income Taxes	(51,012)	(74,191)	(69,071)	(69,971)	(104,402)
409.2	Income Taxes	7,777,599	7,907,502	8,176,729	8,543,917	19,837,879
411.2	Provision for Deferred Inc. Tax- Cr.	85,390	209,278	(349,102)	(651,277)	(528,491)
420	Investment Tax Credit Adj - Net	756	86,146	(425,696)	86,146	86,146
	Total Other Income and Deductions	7,398,614	9,475,269	(3,253,531)	(1,862,607)	(19,318,546)
Interest Charges debit (credit)						
427	Interest on Long Term Debt	128,081,571	128,848,034	131,822,069	137,642,470	137,475,807
428	Amort of Debt Discount and Expense	2,479,434	2,875,603	2,927,387	2,910,231	2,794,067
428.1	Amort of Loss on Reacquired Debt	1,006,814	377,375	378,265	631,993	666,967
429.1	Amort of Gain on Reacquired Debt	-				
430	Interest on Debt to Associated Companies	(959)	11,152	2,100	1,015	-
431	Other Interest Expense	3,091,726	1,939,941	3,338,398	2,292,231	3,161,184
432	Allow for Borrowed Funds Used During Const	(10,564,320)	(11,103,920)	(3,871,317)	(4,675,975)	(6,059,913)
	Net Interest Charges	124,094,266	122,948,185	134,596,902	138,801,965	138,038,112
	Income Before Extraordinary Items	169,043,751	162,409,702	152,777,561	233,990,098	194,671,177

Kansas City Power & Light Company
SECTION 8 FINANCIAL AND OPERATING DATA
Comparative Income and Retained Earnings Statements
Source -Calendar Year - FERC Form 1, pages 114-117 and 118-119.
Source -Test Year -Test Yr Query

Primary Account	Description	Calendar Year Ending 2013	2014	2015	Test Year Ending 12 months ended Sep-16	12 months ended Sep-17
	STATEMENT OF RETAINED EARNINGS debit (credit)					
216	**Unappropriated Retained Earnings**					
	Balance - Beginning of Year	543,340,330	616,151,777	701,346,037	828,250,617	979,398,202
433 less 418.1	Balance Transferred from Income	164,811,447	157,194,260	147,660,067	228,147,585	189,382,254
438	Dividends Declared - Common Stock	(92,000,000)	(72,000,000)	-	(77,000,000)	(182,000,000)
	Transfers from 216.1, Unappr Undist Sub Earn					
	Balance - End of Year	616,151,777	701,346,037	849,006,104	979,398,202	986,780,456
215	**Appropriated Retained Earnings**	0	-	-	-	-
216.1	**Unappropriated Undistributed Subsidiary Retained Earnings**					
	Balance - Beginning of Year	10,675,028	14,907,332	20,122,774	22,089,205	27,931,718
	Equity in Earnings for Year	4,232,304	5,215,442	5,117,494	5,842,513	5,288,923
	Transfer of Earnings to appropriate Ret Earn Acct					
	Balance - End of Year	14,907,332	20,122,774	25,240,268	27,931,718	33,220,641

Kansas City Power & Light Company
SECTION 8 FINANCIAL AND OPERATING DATA
Operating Revenue and Expenses by Primary Account
Source - Calendar Year -FERC Form 1, pages 300-301 and 320-323
Source - Test Year -Per Book Query

Primary Account	Description	Calendar Year Ending 2013	2014	2015	Test Year Ending 12 months ended Sep-16	12 months ended Sep-17
ELECTRIC OPERATING REVENUES						
(debit) credit						
Total Revenues						
440	Residential Sales	625,341,407	630,229,485	648,290,700	717,488,942	717,269,405
442	Commercial and Industrial Sales	829,561,432	849,469,538	895,647,019	974,561,193	1,004,315,995
444	Public Street & Highway Lighting	12,929,839	12,294,825	12,460,211	13,329,082	11,520,871
	Total Sales to Ultimate Customers	1,467,832,678	1,491,993,848	1,556,397,930	1,705,379,217	1,733,106,271
447	Sales for Resale	186,655,481	220,318,092	134,065,969	145,063,693	115,974,244
	Total Sales of Electricity	1,654,488,159	1,712,311,940	1,690,463,899	1,850,442,910	1,849,080,515
449.1	Less Provision for rate refunds	173,238	-	-	522,997	938,015
	Total Revenues	1,654,314,921	1,712,311,940	1,690,463,899	1,849,919,913	1,848,142,500
Other Operating Revenues						
450	Forfeited Discounts	3,328,963	3,464,901	3,488,028	3,531,665	3,776,657
451	Miscellaneous Service Revenues	1,254,497	1,265,830	1,071,081	1,238,849	930,256
454	Rent From Electric Property	2,946,288	3,409,569	4,050,626	4,121,607	3,910,372
456	Other Electric Revenues	9,577,340	10,312,038	14,739,568	13,951,113	17,011,591
	Total Other Electric Revenues	17,107,088	18,452,338	23,349,303	22,843,234	25,628,876
	Total Electric Operating Revenues	1,671,422,009	1,730,764,278	1,713,813,202	1,872,763,147	1,873,771,376
ELECTRIC OPERATING EXPENSES						
debit (credit)						
Power Production Expenses						
	Steam Power Generation					
500	Operation Supervision and Eng	9,006,911	5,287,808	5,574,918	6,902,295	8,389,111
501	Fuel	350,718,716	332,485,753	274,329,274	269,317,396	223,812,167
502	Steam Expenses	19,558,060	18,276,085	22,115,124	19,636,879	15,840,475
503	Steam from Other Sources	-			-	-
505	Electric Expenses	7,044,541	7,858,553	7,519,187	6,916,280	6,718,074
506	Misc Steam Power Expenses	8,684,821	10,686,928	10,614,013	11,240,661	11,587,983
507	Rents	160,093	313,390	176,867	281,784	288,392
509	Allowances	(3,905,868)	(3,929,300)	(3,910,792)	(3,924,352)	(3,982,122)
	Total Steam Operation	391,267,274	370,979,217	316,418,591	310,370,943	262,654,080
	Steam Power Maintenance					
510	Maintenance Supervision & Eng	7,079,743	6,177,491	5,739,150	5,844,350	7,102,017
511	Maintenance of Structures	4,841,301	5,356,744	7,479,425	7,455,864	7,404,691
512	Maintenance of Boiler Plant	31,737,336	31,739,961	28,080,532	27,762,036	34,583,744
513	Maintenance of Electric Plant	6,515,839	6,626,561	8,941,293	4,847,633	4,463,074
514	Maintenance of Misc Steam Plant	415,207	537,458	388,959	286,127	350,019
	Total Steam Maintenance	50,589,426	50,438,215	50,629,359	46,196,010	53,903,545
	Total Steam Power Expenses	441,856,700	421,417,432	367,047,950	356,566,953	316,557,625
	Nuclear Power Operation					
517	Operation Supervision and Eng	9,777,051	7,710,689	7,369,764	7,480,382	7,590,908
518	Fuel	26,556,715	27,356,278	27,123,318	30,779,502	30,867,974
519	Coolants and Water	2,918,728	2,675,868	2,806,299	3,263,770	2,903,445
520	Steam Expenses	19,787,528	13,096,394	16,772,928	14,028,764	13,854,436
523	Electric Expenses	1,143,688	1,139,520	1,349,061	1,407,472	1,408,063
524	Misc Nuclear Power Expenses	26,237,353	34,973,126	30,646,151	34,354,568	26,662,865
	Total Nuclear Operation	86,421,063	86,951,875	86,067,521	91,314,458	83,287,691
	Nuclear Power Maintenance					
528	Maintenance Supervision & Eng	8,954,344	5,535,933	7,118,741	4,792,185	5,100,696
529	Maintenance of Structures	3,245,819	2,843,976	2,776,521	2,503,597	2,420,831
530	Maintenance of Reactor Plant Equip	9,287,675	25,678,971	7,334,882	17,789,932	11,579,526
531	Maintenance of Electric Plant	8,466,844	2,986,323	6,139,186	3,360,662	4,019,234
532	Maintenance of Misc Nuclear Plant	3,061,206	2,865,534	2,932,271	3,007,539	2,740,805
	Total Nuclear Maintenance	33,015,888	39,910,737	26,301,601	31,453,915	25,861,092
	Total Nuclear Power Expenses	119,436,951	126,862,612	112,369,122	122,768,373	109,148,783

Kansas City Power & Light Company
SECTION 8 FINANCIAL AND OPERATING DATA
Operating Revenue and Expenses by Primary Account
Source - Calendar Year -FERC Form 1, pages 300-301 and 320-323
Source - Test Year -Per Book Query

Primary Account	Description	Calendar Year Ending 2013	Calendar Year Ending 2014	Calendar Year Ending 2015	Test Year Ending 12 months ended Sep-16	Test Year Ending 12 months ended Sep-17
	Other Power Operation					
546	Operation Supervision and Eng	213,839	167,207	100,468	92,921	116,079
547	Fuel	9,594,490	8,998,561	6,964,108	7,409,535	6,959,439
548	Generation Expenses	1,140,037	989,043	1,010,721	1,089,302	902,476
549	Misc Other Power Gen Expenses	2,302,259	1,405,140	1,284,596	1,240,577	1,298,562
550	Rents	-	-	-	-	-
	Total Othr Power Operation	13,250,625	11,559,951	9,359,893	9,832,335	9,276,556
	Other Power Maintenance					
551	Maintenance Supervision & Eng	341,087	87,253	51,160	69,949	37,866
552	Maintenance of Structures	167,361	122,602	105,208	168,749	167,873
553	Mtce of Generating and Elec Plant	1,600,611	2,006,835	1,972,666	2,317,465	2,299,364
554	Mtce of Misc Other Power Gen Plant	100,265	80,182	29,274	12,563	33,312
	Total Other Power Maintenance	2,209,324	2,296,872	2,158,308	2,568,726	2,538,415
	Total Other Power Expenses	15,459,949	13,856,823	11,518,201	12,401,061	11,814,971
	Other Power Supply Expenses					
555	Purchased Power	62,419,571	107,785,022	92,558,306	112,294,352	144,601,307
556	System Control & Load Dispatching	2,979,307	2,063,809	1,888,734	2,039,011	1,838,487
557	Other Expenses	7,021,647	8,982,387	6,165,816	(24,030,318)	(5,518,014)
	Total Other Power Supply Exp	72,420,525	118,831,218	100,612,856	90,303,045	140,921,780
	Total Power Production Expenses	649,174,125	680,968,085	591,548,129	582,039,432	578,443,159
Transmission Expenses						
	Transmission Operation					
560	Operation Supervision & Engineering	1,105,045	587,976	780,753	1,070,787	824,635
561	Load Dispatching	6,791,142	7,252,539	7,768,229	6,483,626	7,053,685
562	Station Expenses	385,742	357,367	583,203	576,429	741,821
563	Overhead Line Expenses	96,019	128,266	164,779	185,347	312,482
564	Underground Line Expenses	-	-	-	6,154	13,000
565	Transmission of Electricity by Others	37,313,845	47,170,314	58,382,946	60,869,535	64,483,724
566	Misc Transmission Expenses	2,008,723	3,103,751	2,408,236	2,591,360	2,920,641
567	Rents	2,381,951	2,412,368	2,414,011	2,397,237	2,423,612
	Total Transmission Operation	50,082,467	61,012,581	72,502,157	74,180,475	78,773,600
	Transmission Maintenance					
568	Maintenance Supervision & Eng	-	7,142	33,907	119,076	(80,246)
569	Maintenance of Structures	2,512	-	-	-	-
570	Maintenance of Station Equipment	977,598	789,366	808,309	848,819	644,576
571	Maintenance of Overhead Lines	2,866,941	2,456,852	2,355,800	2,354,823	2,335,190
572	Maintenance of Underground Lines	48,733	96,563	(76,170)	12,223	5,624
573	Maintenance of Miscellaneous Transmission Plant	8,185	5,450	5,821	6,379	5,821
575.2	Day-Ahead and Real-Time Market Facilitation				-	-
575.3	Transmission Rights Market Facilitation				-	-
575.5	Ancillary Services Market Administration					-
575.7	Market monitor, compliance	4,601,981	5,878,416	6,931,864	5,277,814	6,646,953
576.2	Maintenance of Computer Hardware				-	-
576.3	Maintenance of Computer Software				-	-
	Total Transmission Maintenance	8,505,950	9,233,789	10,059,531	8,619,134	9,557,918
	Total Transmission Expenses	58,588,417	70,246,370	82,561,688	82,799,609	88,331,518
Distribution Expenses						
	Distribution Operation					
580	Operation Supervision & Engineering	3,386,754	1,929,628	2,994,270	4,740,285	3,461,005
581	Load Dispatching	745,845	772,123	1,053,597	777,477	492,771
582	Station Expenses	184,762	161,484	144,729	151,655	139,089
583	Overhead Line Expenses	1,774,487	1,529,813	1,573,689	2,454,093	2,249,576
584	Underground Line Expenses	2,397,425	2,543,245	3,136,233	3,755,416	4,033,947
585	Street Lighting & Signal System Exp	27,945	69,416	9,986	7,128	49
586	Meter Expenses	1,947,441	2,246,390	2,170,376	2,489,992	2,629,165
587	Customer Installation Expenses	256,363	361,471	358,549	273,817	137,140
588	Miscellaneous Expenses	15,306,056	14,422,737	13,550,672	13,722,482	13,937,944
589	Rents	78,660	101,425	52,807	77,456	79,453
	Total Distribution Operations	26,105,738	24,137,732	25,044,908	28,449,801	27,160,139

Kansas City Power & Light Company
SECTION 8 FINANCIAL AND OPERATING DATA
Operating Revenue and Expenses by Primary Account
Source - Calendar Year -FERC Form 1, pages 300-301 and 320-323
Source - Test Year -Per Book Query

Primary Account	Description	Calendar Year Ending 2013	2014	2015	Test Year Ending 12 months ended Sep-16	12 months ended Sep-17
	Distribution Maintenance					
590	Maintenance Supervision & Eng	182,247	229,711	184,290	141,047	91,832
591	Maintenance of Structures	520,956	161,921	106,591	12,082	681
592	Maintenance of Station Equipment	773,396	789,791	825,026	919,197	877,453
593	Maintenance of Overhead Lines	20,982,069	20,441,310	20,892,634	20,881,428	21,475,027
594	Maintenance of Underground Lines	1,460,601	2,366,885	2,505,531	2,469,685	1,957,087
595	Maintenance of Line Transformers	315,440	2,433	255,271	307,896	325,895
596	Mtce of Street Lighting & Signal Syst	1,185,894	1,138,410	1,216,229	1,041,300	672,414
597	Maintenance of Meters	382,232	365,116	366,392	315,651	188,552
598	Mtce of Misc Distribution Plant	1,706,392	1,535,795	2,025,623	2,046,416	2,098,872
	Total Distribution Maintenance	27,509,227	27,031,372	28,377,587	28,134,702	27,687,813
	Total Distribution Expenses	53,614,965	51,169,104	53,422,495	56,584,503	54,847,952
Customer Accounts Expenses						
901	Supervision	1,123,118	184,942	596,420	680,305	304,595
902	Meter Reading Expenses	4,319,765	4,087,748	4,574,355	4,996,721	4,653,849
903	Customer Records & Collection Exp	12,873,731	13,313,420	13,363,911	13,638,880	13,933,048
904	Uncollectible Accounts	-	-	-	-	-
905	Misc Customer Accounts Expenses	894,377	1,468,977	1,739,056	1,248,282	765,547
	Total Customer Accounts Exp	19,210,991	19,055,087	20,273,742	20,564,188	19,657,039
Customer Service & Informational Expenses						
907	Supervision	72,437	51,915	119,232	96,305	94,797
908	Customer Assistance Expenses	11,208,486	15,080,935	28,866,562	37,894,668	37,945,410
909	Informational & Instructional Expense	248,836	111,018	97,398	71,900	184,947
910	Misc. Customer Service and Informational Exp.	2,129,470	2,308,756	3,814,689	8,837,366	8,923,314
	Total Cust Svc & Informational Exp	13,659,229	17,552,624	32,897,881	46,900,239	47,148,468
Sales Expenses						
911	Supervision	3				
912	Demonstration & Selling Expenses	358,973	403,340	473,126	495,470	528,411
913	Advertising	-	-	(3,152)	(150)	-
916	Miscellaneous Sales Expenses	63,560	-	273	-	-
	Total Sales Expenses	422,536	403,340	470,247	495,320	528,411
Administrative & General Expenses						
	Admin & General Operations					
920	Administrative & General Salaries	42,272,388	39,419,210	38,531,990	37,741,601	39,884,474
921	Office Supplies and Expenses	(1,381,907)	(46,241)	(833,182)	(35,434)	(1,007,383)
922	A&G Expenses Transferred - Credit	(4,666,954)	(6,198,182)	(12,852,633)	(13,935,856)	(15,373,708)
923	Outside Services Employed	12,449,443	14,928,001	16,256,378	12,964,842	13,899,859
924	Property Insurance	4,619,477	4,484,045	4,423,092	4,181,006	4,056,361
925	Injuries and Damages	7,214,674	10,103,124	9,626,308	8,389,683	18,415,953
926	Employee Pensions and Benefits	69,852,014	76,625,030	81,157,597	83,238,480	84,153,444
928	Regulatory Commission Expenses	9,210,096	8,046,627	8,283,426	7,310,221	7,489,577
929	Duplicate Charges - Credit	(12,687)			-	
930.1	General Advertising Expenses	22,273	276			35,660
930.2	Miscellaneous General Expenses	5,584,432	5,404,714	5,980,737	5,959,587	6,298,107
931	Rents	4,919,098	3,165,984	3,276,800	3,559,602	3,022,905
	Total Admin & General Operations	150,082,347	155,932,588	153,850,513	149,373,732	160,875,249
935	Maintenance of General Plant	5,675,249	5,965,590	6,954,895	7,980,063	8,582,591
	Total Admin & General Expense	155,757,596	161,898,178	160,805,408	157,353,795	169,457,840
	Total Electric Oper & Maint Exp	950,427,859	1,001,292,788	941,979,590	946,737,086	958,414,387

Kansas City Power & Light Company
SECTION 8: FINANCIAL AND OPERATING DATA
Sales of Electric ty by Rate Schedule

Source Calendar Year - KCC Supplemental Annual Report to the FERC Form 1, page 11-11.2
Source Test Year -Query
SALES OF ELECTRICITY BY RATE SCHEDULE KANSAS ONLY CALENDAR YEARS 2013 2017

Revenue Classification	Number and Title of Rate Schedule		MWh Sold	Revenue	Average Number of Customers	KWh of Sales Per Customer	Revenue Per KWH Sold
SALES OF ELECTRICITY BY RATE SCHEDULE KANSAS FY2013							
RESIDENTIAL SALES (440)							
	2ALDA	Area Lighting	1,084	372,434	1,938	559	0.3435
	2RO1A	Residential Standard Service	58	10,030	16	3,645	0.1720
	2RS1A	Residential Standard Service	1,844,327	221,654,519	153,082	12,048	0.1202
	2RS2A	Residential w/ Submeter Heat	12,495	1,345,331	934	13,378	0.1077
	2RS3A	Residential w/ Separate Ht Mtr	167,237	17,668,444	10,662	15,685	0.1056
	2RS6A	Residential w/ Elec Heat 1-Mtr	389,332	42,650,186	25,320	15,376	0.1095
	2RSDA	Residential Standard 3Ph AC	1,587	177,437	32	49,581	0.1118
	2RW1A	Res Standard w/ Water Heat	4,702	490,939	298	15,779	0.1044
	2RW2A	Res w/ Water & Sub Space Heat	1,415	129,825	66	21,441	0.0917
	2RW3A	Res w/ Water & Sep Space Heat	24,335	2,192,753	912	26,683	0.0901
	2RW6A	Res w/ Water & Space Ht 1-Mtr	366,661	38,890,415	24,387	15,035	0.1061
	2RW7A	Res w/ Water & Sep Space Heat	1,573	157,197	51	30,851	0.0999
	2TE1A	Residential Time-of-Day	747	86,536	56	13,334	0.1159
	4ALDC	Area Lighting	(1)	(115)	1	-787	0.1461
	FUEL CLAUSE ACCRUAL			839,505			
	PROPERTY TAX SURCHARGE			(590,157)			
	NET METERING		30				
	UNBILLED REVENUE		14,031	1,330,584			0.0948
	TOTAL RESIDENTIAL		2 829 613	327 405 863	217 755	12 994	0.1157
COMMERCIAL SALES (442)							
	2ALDE	Area Lighting	2,030	542,351	736	2,758	0.2672
	2LGAE	Large General Space Heating	685,537	53,957,932	294	2,331,759	0.0787
	2LGAF	Large General Space Heating	21,432	1,170,247	2	10,715,880	0.0546
	2LGHE	Large General w/ Heat Meter	90,175	7,661,229	56	1,610,261	0.0850
	2LGSE	Large General Service	985,998	87,779,516	648	1,521,602	0.0890
	2LGSF	Large General Service	204,941	16,982,793	33	6,210,343	0.0829
	2LGSW	Large General Service	98,745	5,897,994	1	98,745,000	0.0597
	2LS1E	Off-Peak Lighting Service	40,261	2,962,402	1,554	25,908	0.0736
	2MGAE	Medium General Space Heating	105,977	9,805,781	413	256,603	0.0925
	2MGAF	Medium General Space Heating	164	15,071	1	163,880	0.0920
	2MGHE	Medium General w/ Heat Meter	19,887	2,069,109	108	184,140	0.1040
	2MGSE	Medium General Service	591,618	64,669,116	3,429	172,534	0.1093
	2MGSF	Medium General Service	2,363	387,383	5	472,630	0.1639
	2MLIK	Commercial St Lght Incandescnt	0	45	1	137	0.3285
	2MLSK	Commercial St Light HP Sodium	2	667	1	1,776	0.3756
	2PGSW	Large Power Service	5,270	1,693,812	-	-	0.3214
	2SGAE	Sma l General Space Heating	20,567	2,410,767	1,117	18,413	0.1172
	2SGAF	Sma l General Space Heating	10	1,382	2	5,147	0.1343
	2SGHE	Sma l General w/ Heat Meter	10,342	1,233,286	392	26,382	0.1193
	2SGSE	Sma l General Service	275,191	36,297,868	18,621	14,779	0.1319
	2SGSF	Sma l General Service	254	24,309	3	84,747	0.0956
	2SUSE	Sma l General Unmetered	2,760	478,838	948	2,912	0.1735
	2TSLM-Traffic Signal Lights		-	-	-	-	-
	ECKC-Manual ECA Charge		(0)				
	WIND GENERATION		0	4			0.1333
	FUEL CLAUSE ACCRUAL			3,511,158			
	PROPERTY TAX SURCHARGE			(706,971)			
	NET METERING		27				
	UNBILLED REVENUE		1 886	50 503			0.0268
	TOTAL COMMERCIAL		3 165 438	298 896 592	28 364	111 601	0.0944
INDUSTRIAL SALES (442)							
	2LGAH	Large General Space Heating	21,382	1,861,406	10	2,138,162	0.0871
	2LGHH	Large General w/ Heat Meter	1,419	113,841	1	1,418,880	0.0802
	2LGSG	Large General Service	48,924	3,981,736	11	4,447,593	0.0814
	2LGSH	Large General Service	151,424	13,284,656	56	2,704,006	0.0877
	2LGSV	Large General Service	7,803	635,905	1	7,803,000	0.0815
	2MGAH	Medium General Space Heating	2,288	265,105	6	381,295	0.1159
	2MGHH	Medium General w/ Heat Meter	566	69,922	4	141,461	0.1236
	2MGSG	Medium General Service	4	1,726	1	4,284	0.4029
	2MGSH	Medium General Service	28,387	3,214,770	156	181,966	0.1132
	2PGSG	Large Power Service	-	-	-	-	-
	2PGSV	Large Power Service	-	-	-	-	-
	2SGAH	Sma l General Space Heating	398	44,656	13	30,633	0.1121
	2SGHH	Sma l General w/ Heat Meter	56	5,795	3	18,727	0.1031
	2SGSG	Sma l General Service	0	205	1		
	2SGSH	Sma l General Service	16,213	1,877,013	703	23,062	0.1158
	ASH GROVE AGGREGATE INC			(9,596)	0		
	FUEL CLAUSE ACCRUAL			(2,505,729)			
	PROPERTY TAX SURCHARGE			(45,616)			
	NET METERING						
	UNBILLED REVENUE		593	23,389			0.0395
	TOTAL INDUSTRIAL		279 456	22 819 184	966	289 292	0.0817
PUBLIC STREET AND HIGHWAY LIGHTING (444)							
	2MLCL	Municipal St Light Cust Owned	4	768	1	3,975	0.1932
	2MLIL	Municipal St Lght Incandescent	109	19,507	13	8,384	0.1790
	2MLLL	Municipal St Lght LED	217	181,548	5	43,481	0.8351
	2MLML	Municipal St Light Merc Vapor	721	158,294	25	28,824	0.2197
	2MLSL	Municipal St Light HP Sodium	11,059	4,312,880	43	257,189	0.3900
	2MOSL	Municipal Ornamental St Light	43	51,345	2	21,648	1.1859
	2TSLM	Traffic Signal Lights	2,554	1,364,297	12	212,868	0.5341
	FUEL CLAUSE ACCRUAL			3,700			
	PROPERTY TAX SURCHARGE			(3,200)			
	TOTAL STREET LIGHTS		14 708	6 089 139	101	145 622	0.4140
TOTAL BILLED			6,272,705	653,806,302	247,186	25,376	0.1042
TOTAL UNBILLED REVENUE			16,510	1,404,476	0		0.0851
TOTAL			6 289 214	655 210 778	247 186	25 443	0.1042

Kansas City Power & Light Company
SECTION 8: FINANCIAL AND OPERATING DATA
Sales of Electric ty by Rate Schedule

Source Calendar Year - KCC Supplemental Annual Report to the FERC Form 1, page 11-11.2
Source Test Year -Query
SALES OF ELECTRICITY BY RATE SCHEDULE KANSAS ONLY CALENDAR YEARS 2013 2017

Revenue Classification	Number and Title of Rate Schedule		MWh Sold	Revenue	Average Number of Customers	KWh of Sales Per Customer	Revenue Per KWH Sold
SALES OF ELECTRICITY BY RATE SCHEDULE KANSAS 2014							
RESIDENTIAL SALES (440)							
	2ALDA	Area Lighting	1,055	369,695	1,898	556	0.3504
	2RO1A	Residential Standard	111	19,983	37	3,009	0.1795
	2RS1A	Residential Standard Service	1,839,191	221,800,885	154,228	11,925	0.1206
	2RS2A	Residential w/ Submeter Heat	13,731	1,452,023	987	13,912	0.1057
	2RS3A	Residential w/ Separate Ht Mtr	196,797	20,267,034	11,516	17,089	0.1030
	2RS6A	Residential w/ Elec Heat 1-Mtr	398,065	43,720,228	26,420	15,067	0.1098
	2RSDA	Residential Standard 3Ph AC	1,502	167,790	29	51,810	0.1117
	2RW1A	Res Standard w/ Water Heat	0	49	0	0	0.1225
	2RW2A	Res w/ Water & Sub Space Heat	2	150	0	0	0.0944
	2RW3A	Res w/ Water & Sep Space Heat	12	(2,467)	1	11,549	-0.2136
	2RW6A	Res w/ Water & Space Ht 1-Mtr	386,279	40,673,381	24,919	15,501	0.1053
	2RW7A	Res w/ Water & Sep Space Heat	1,667	163,894	50	33,340	0.0983
	2TE1A	Residential Time-of-Day	727	84,327	56	12,976	0.1161
	ECKRS	Res Manual ECA Charge	(0)	0			0.0000
	EKRES	Res Manual EER Charge	(0)	0			0.0000
	PTKRS	Res Manual PTR Charge	(0)	0			0.0000
	FUEL CLAUSE ACCRUAL			991,811			
	PROPERTY TAX SURCHARGE			986,888			
	NET METERING		93				
	UNBILLED REVENUE		(16 592)	(1 359 785)			0.0820
	TOTAL RESIDENTIAL		2,822,640	329,335,886	220,141	12,822	0.1167
COMMERCIAL SALES (442)							
	2ALDE	Area Lighting	1,970	531,475	715	2,756	0.2698
	2LGAE	Large General Space Heating	723,885	57,380,360	303	2,389,059	0.0793
	2LGAF	Large General Space Heating	22,846	1,324,737	2	11,423,120	0.0580
	2LGHE	Large General w/ Heat Meter	91,023	7,755,650	56	1,625,411	0.0852
	2LGSE	Large General Service	992,072	88,636,372	656	1,512,306	0.0893
	2LGSF	Large General Service	206,648	17,046,454	34	6,077,887	0.0825
	2LGSW	Large General Service	104,424	7,603,949	1	104,424,000	0.0728
	2LS1E	Off-Peak Lighting Service	39,358	2,951,461	1,496	26,309	0.0750
	2MGAE	Medium General Space Heating	110,236	10,258,003	417	264,354	0.0931
	2MGAF	Medium General Space Heating	560	46,963	2	280,000	0.0839
	2MGHE	Medium General w/ Heat Meter	20,279	2,104,078	105	193,134	0.1038
	2MGSE	Medium General Service	595,445	65,523,209	3,431	173,549	0.1100
	2MGSF	Medium General Service	1,511	262,622	4	377,631	0.1739
	2MLSK	Commercial St Light HP Sodium	2	674	1	1,788	0.3770
	2SGAE	Sma l General Space Heating	22,062	2,579,565	1,122	19,663	0.1169
	2SGAF	Sma l General Space Heating	10	1,295	2	4,893	0.1323
	2SGHE	Sma l General w/ Heat Meter	10,887	1,276,307	394	27,633	0.1172
	2SGSE	Sma l General Service	285,475	37,839,135	19,200	14,869	0.1325
	2SGSF	Sma l General Service	276	27,022	3	92,084	0.0978
	2SUSE	Sma l General Unmetered	2,744	503,823	936	2,931	0.1836
	ECKCS	Manual ECA Charge	(0)				
	EKMCS	Medium Gen Manual EER Charge	0				
	EKSCS	Sma l Gen Manual EER Charge	(0)				
	EKLCS	Large Gen Manual EER Charge	0				
	PTKCS	Manual PTR Charge	(0)				
	FUEL CLAUSE ACCRUAL			1,124,431			
	PROPERTY TAX SURCHARGE			1,030,149			
	NET METERING		51				
	UNBILLED REVENUE		(14,573)	(913,606)			0.0627
	TOTAL COMMERCIAL		3 217 192	304 894 128	28 880	111 399	0.0948
INDUSTRIAL SALES (442)							
	2LGAH	Large General Space Heating	22,758	1,955,521	11	2,068,907	0.0859
	2LGHH	Large General w/ Heat Meter	1,513	124,837	1	1,513,440	0.0825
	2LGSG	Large General Service	61,740	4,665,974	11	5,612,772	0.0756
	2LGSH	Large General Service	156,742	13,737,511	56	2,798,962	0.0876
	2LGSV	Large General Service	22,732	1,631,996	1	22,732,000	0.0718
	2MGAH	Medium General Space Heating	2,786	318,164	7	398,043	0.1142
	2MGHH	Medium General w/ Heat Meter	640	75,295	4	160,058	0.1176
	2MGSG	Medium General Service	26	3,876	1	26,018	0.1490
	2MGSH	Medium General Service	27,374	3,084,526	158	173,251	0.1127
	2SGAH	Sma l General Space Heating	982	98,511	15	65,493	0.1003
	2SGHH	Sma l General w/ Heat Meter	68	6,573	3	22,608	0.0969
	2SGSG	Sma l General Service	0	208	1	0	
	2SGSH	Sma l General Service	16,161	1,870,352	695	23,253	0.1157
	ASH GROVE AGGREGATE INC		0	(10,692)			
	FUEL CLAUSE ACCRUAL		0	98,727			
	PROPERTY TAX SURCHARGE		0	98,442			
	UNBILLED REVENUE		(782)	(68 986)			0.0882
	TOTAL INDUSTRIAL		312,741	27,690,835	964	324,420	0.0885
PUBLIC STREET AND HIGHWAY LIGHTING (444)							
	2MLIL	Municipal St Lght Incandescent	104	18,312	12	8,666	0.1761
	2MLLL	Municipal St Light LED	231	200,786	5	46,199	0.8692
	2MLML	Municipal St Light Merc Vapor	679	150,922	23	29,522	0.2223
	2MLSL	Municipal St Light HP Sodium	9,166	3,558,847	41	223,563	0.3883
	2MOSL	Municipal Ornamental St Light	44	52,430	2	21,904	1.1968
	2TSLM	Traffic Signal Lights	2,546	1,374,205	12	212,163	0.5398
	FUEL CLAUSE ACCRUAL		0	5,207			
	PROPERTY TAX SURCHARGE		0	6,305			
	TOTAL STREET LIGHTS		12,770	5,367,014	95	134,419	0.4203
TOTAL BILLED			6,397,289	669,630,240	250,080	25,581	0.1047
TOTAL UNBILLED REVENUE			(31 947)	(2 342 377)	0		0.0733
TOTAL			6,365,343	667,287,863	250,080	25,453	0.1048

Kansas City Power & Light Company
SECTION 8: FINANCIAL AND OPERATING DATA
Sales of Electric ty by Rate Schedule

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Source Test Year -Query
SALES OF ELECTRICITY BY RATE SCHEDULE   KANSAS ONLY CALENDAR YEARS 2013 2017

Revenue Classification	Number and Title of Rate Schedule		MWh Sold	Revenue	Average Number of Customers	KWh of Sales Per Customer	Revenue Per KWH Sold
SALES OF ELECTRICITY BY RATE SCHEDULE KANSAS 2015							
RESIDENTIAL SALES (440)							
	2ALDA	Area Lighting	1,031	389,646	1,901	542	0.3778
	2RO1A	Residential Standard	179	33,702	61		
	2RS1A	Residential Standard Service	1,810,518	230,495,545	155,052	11,677	0.1273
	2RS2A	Residential w/ Submeter Heat	11,890	1,356,105	967	12,296	0.1141
	2RS3A	Residential w/ Separate Ht Mtr	173,526	19,166,044	11,474	15,123	0.1105
	2RS6A	Residential w/ Elec Heat 1-Mtr	396,639	46,431,722	28,491	13,922	0.1171
	2RSDA	Residential Standard 3Ph AC	1,379	162,305	26	53,046	0.1177
	2RW1A	Res Standard w/ Water Heat	(1)	(166)			0.1113
	2RW2A	Res w/ Water & Sub Space Heat	(0)	(38)			0.1169
	2RW3A	Res w/ Water & Sep Space Heat	1	(79)			-0.0721
	2RW6A	Res w/ Water & Space Ht 1-Mtr	343,541	38,800,102	25,039	13,720	0.1129
	2RW7A	Res w/ Water & Sep Space Heat	1,459	153,329	50	29,182	0.1051
	2TE1A	Residential Time-of-Day	705	86,488	55	12,824	0.1226
	ECKRS	Res Manual ECA Charge					
	EKRES	Res Manual EER Charge					
	PTKRS	Res Man PTR Charge					
	FUEL CLAUSE ACCRUAL			(740,442)			
	PROPERTY TAX SURCHARGE			417,592			
	NET METERING		156				
	UNBILLED REVENUE		(2,216)	1,057,053			-0.4769
	TOTAL RESIDENTIAL		2 738 806	337 808 908	223 116	12 275	0.1233
COMMERCIAL SALES (442)							
	2ALDE	Area Lighting	1,930	572,176	735	2,626	0.2965
	2LGAE	Large General Space Heating	689,178	57,838,058	301	2,289,629	0.0839
	2LGAF	Large General Space Heating	42,644	3,026,974	3	14,214,598	0.0710
	2LGHE	Large General w/ Heat Meter	82,997	7,514,461	56	1,482,087	0.0905
	2LGSE	Large General Service	1,024,904	96,105,811	676	1,516,130	0.0938
	2LGSF	Large General Service	175,623	15,519,772	30	5,854,104	0.0884
	2LGSW	Large General Service	103,200	7,821,825	1	103,200,000	0.0758
	2LS1E	Off-Peak Lighting Service	40,349	3,198,190	1,525	26,459	0.0793
	2MGAE	Medium General Space Heating	105,848	10,453,068	422	250,824	0.0988
	2MGAF	Medium General Space Heating	2,880	438,358	5	576,006	0.1522
	2MGHE	Medium General w/ Heat Meter	17,798	1,979,905	102	174,492	0.1112
	2MGSE	Medium General Service	588,056	67,754,545	3,394	173,263	0.1152
	2MGSF	Medium General Service	641	73,690	3	213,688	0.1149
	2MLSK	Commercial St Light HP Sodium	2	698	1	1,686	0.4140
	2SGAE	Sma l General Space Heating	22,260	2,735,685	1,137	19,578	0.1229
	2SGAF	Sma l General Space Heating	386	59,998	4	96,558	0.1553
	2SGHE	Sma l General w/ Heat Meter	9,890	1,258,862	394	25,103	0.1273
	2SGSE	Sma l General Service	295,384	40,844,454	19,509	15,141	0.1383
	2SGSF	Sma l General Service	283	31,783	4	70,735	0.1123
	2SUSE	Sma l General Unmetered	2,741	525,136	944	2,903	0.1916
	2TSLM	Traffic Signal Lights					
	ECKCS	MANUAL ECA CHARGE					
	EKMCS	MEDIUM GEN MANUAL EER CHARGE					
	PTKCS	MANUAL PTR CHARGE					
	FUEL CLAUSE ACCRUAL		0	(942,842)			
	PROPERTY TAX SURCHARGE		0	263,310			
	NET METERING		63				
	UNBILLED REVENUE		(2,063)	926,767			-0.4493
	TOTAL COMMERCIAL		3 204 994	318 000 684	29 246	109 587	0.0992
INDUSTRIAL SALES (442)							
	2LGAH	Large General Space Heating	21,634	1,903,353	10	2,163,408	0.0880
	2LGHH	Large General w/ Heat Meter	1,514	130,491	1	1,514,117	0.0862
	2LGSG	Large General Service	62,657	5,094,895	11	5,696,086	0.0813
	2LGSH	Large General Service	155,499	14,448,899	56	2,776,770	0.0929
	2LGSV	Large General Service	22,542	1,724,021	1	22,542,000	0.0765
	2MGAH	Medium General Space Heating	3,519	412,203	8	439,840	0.1171
	2MGHH	Medium General w/ Heat Meter	582	75,902	4	145,574	0.1303
	2MGSG	Medium General Service	46	6,697	1	45,606	0.1468
	2MGSH	Medium General Service	26,761	3,130,198	156	171,548	0.1170
	2SGAH	Small General Space Heating	264	33,529	14	18,887	0.1268
	2SGHH	Small General w/ Heat Meter	51	5,436	3	16,941	0.1070
	2SGSG	Small General Service	0	218	1		
	2SGSH	Small General Service	15,879	1,926,589	685	23,181	0.1213
	ASH GROVE AGGREGATE INC		0	(10,053)	0		
	FUEL CLAUSE ACCRUAL		0	-81,579			
	PROPERTY TAX SURCHARGE		0	32,310			
	UNBILLED REVENUE		(522)	49 552			-0.0949
	TOTAL INDUSTRIAL		310 426	28 882 661	951	326 421	0.0930
PUBLIC STREET AND HIGHWAY LIGHTING (444)							
	2MLIL	Municipal St Lght Incandescent	98	18,804	11	8,937	0.1913
	2MLLL	Municipal St Light LED	156	149,043	4	38,934	0.9570
	2MLML	Municipal St Light Merc Vapor	634	152,549	21	30,204	0.2405
	2MLSL	Municipal St Light HP Sodium	8,251	3,458,532	39	211,569	0.4192
	2MOSL	Municipal Ornamental St Light	17	18,803	1	16,538	1.1370
	2TSLM	Traffic Signal Lights	2,522	1,442,361	12	210,194	0.5718
	ECKTS	Manual ECA Charge	0	0	0		
	PTKTS	Manual PTR Charge	2	0	0		
	FUEL CLAUSE ACCRUAL		0	(232)			
	PROPERTY TAX SURCHARGE		0	2,277			
	TOTAL STREET LIGHTS		11 680	5 242 137	88	132 729	0.4488
TOTAL BILLED			6,270,708	687,901,018	253,401	24,746	0.1097
TOTAL UNBILLED REVENUE			(4,801)	2,033,372	0		-0.4235
TOTAL			6 265 906	689 934 390	253 401	24 727	0.1101

Kansas City Power & Light Company
SECTION 8: FINANCIAL AND OPERATING DATA
Sales of Electric ty by Rate Schedule

Source Calendar Year - KCC Supplemental Annual Report to the FERC Form 1, page 11-11.2
Source Test Year -Query
SALES OF ELECTRICITY BY RATE SCHEDULE KANSAS ONLY CALENDAR YEARS 2013 2017

Revenue Classification	Number and Title of Rate Schedule		MWh Sold	Revenue	Average Number of Customers	KWh of Sales Per Customer	Revenue Per KWH Sold
SALES OF ELECTRICITY BY RATE SCHEDULE KANSAS 2016							
RESIDENTIAL SALES (440)							
	2ALDA	Area Lighting	1,048	402,266	1,867	561	0.3839
	2RO1A	Residential Standard	606	122,011	260	2,330	0.2014
	2RS1A	Residential Standard Service	1,868,323	255,280,345	155,889	11,985	0.1366
	2RS2A	Residential w/ Submeter Heat	11,275	1,394,375	958	11,769	0.1237
	2RS3A	Residential w/ Separate Ht Mtr	164,481	19,797,078	11,457	14,356	0.1204
	2RS6A	Residential w/ Elec Heat 1-Mtr	411,543	52,065,758	29,929	13,751	0.1265
	2RSDA	Residential Standard 3Ph AC	1,417	176,304	25	56,664	0.1245
	2RW1A	Res Standard w/ Water Heat	-97	(9,655)	3	-32,229	0.0999
	2RW2A	Res w/ Water & Sub Space Heat	2	224	-		0.1062
	2RW3A	Res w/ Water & Sep Space Heat	43	4,092	3	14,438	0.0945
	2RW6A	Res w/ Water & Space Ht 1-Mtr	329,046	40,542,814	25,125	13,096	0.1232
	2RW7A	Res w/ Water & Sep Space Heat	1,399	159,292	50	27,976	0.1139
	2TE1A	Residential Time-of-Day	687	91,533	52	13,215	0.1332
	ECKRS	Res Manual ECA Charge	0	-	-		
	EKRES	Res Manual EER Charge	0	-	-		
	PTKRS	Res Manual PTR Charge	0	-	-		
	FUEL CLAUSE ACCRUAL		0	-			
	PROPERTY TAX SURCHARGE		0	-			
	NET METERING		344				0.0000
	UNBILLED REVENUE		8,052	1 416 904			0.1760
	TOTAL RESIDENTIAL		2,798,169	371,443,341	225,618	12,402	0.1327
COMMERCIAL (442)							
	2ALDE	Area Lighting	1,990	595,049	719	2,768	0.2990
	2LGAE	Large General Space Heating	677,601	60,052,118	297	2,281,486	0.0886
	2LGAF	Large General Space Heating	44,043	3,210,396	4	11,010,815	0.0729
	2LGHE	Large General w/ Heat Meter	77,965	7,427,495	55	1,417,542	0.0953
	2LGSE	Large General Service	1,051,180	104,095,947	684	1,536,813	0.0990
	2LGSF	Large General Service	179,589	16,528,418	29	6,192,720	0.0920
	2LGSW	Large General Service	95,112	7,643,603	1	95,112,000	0.0804
	2LS1E	Off-Peak Lighting Service	39,602	3,284,128	1,535	25,799	0.0829
	2MGAE	Medium General Space Heating	112,300	11,679,397	427	262,999	0.1040
	2MGAF	Medium General Space Heating	3,253	515,109	5	650,652	0.1583
	2MGHE	Medium General w/ Heat Meter	16,710	1,941,614	95	175,899	0.1162
	2MGSE	Medium General Service	600,798	72,686,425	3,321	180,909	0.1210
	2MGSF	Medium General Service	625	63,518	3	208,412	0.1016
	2MLSK	Commercial St Light HP Sodium	2	675	1	1,617	0.4174
	2SGAE	Small General Space Heating	23,451	3,040,471	1,177	19,925	0.1297
	2SGAF	Small General Space Heating	2,788	408,104	5	557,650	0.1464
	2SGHE	Small General w/ Heat Meter	9,379	1,279,658	392	23,925	0.1364
	2SGSE	Small General Service	313,717	45,288,496	19,847	15,807	0.1444
	2SGSF	Small General Service	188	24,242	5	37,509	0.1293
	2SUSE	Small General Unmetered	2,721	545,206	940	2,895	0.2004
	2TSLM	Traffic Signal Lights	0	-	-		
	ECKCS	Manual ECA Charge	0	-	-		
	EKMCS	Medium Gen Manual EER Charge	0	-	-		
	PTKCS	Manual PTR Charge	0	-	-		
	FUEL CLAUSE ACCRUAL		0	-			
	PROPERTY TAX SURCHARGE		0	-			
	NET METERING		71				0.0000
	UNBILLED REVENUE		4,028	800,916			0.1988
	TOTAL COMMERCIAL		3,257,115	341,110,985	29,542	110,254	0.1047
INDUSTRIAL (442)							
	2LGAH	Large General Space Heating	21,415	1,986,829	10	2,141,544	0.0928
	2LGHH	Large General w/ Heat Meter	1,477	133,798	1	1,477,429	0.0906
	2LGSG	Large General Service	62,851	5,475,453	11	5,713,758	0.0871
	2LGSH	Large General Service	147,049	14,348,672	53	2,774,506	0.0976
	2LGSV	Large General Service	24,836	1,977,078	1	24,836,000	0.0796
	2MGAH	Medium General Space Heating	3,656	463,349	8	457,017	0.1267
	2MGHH	Medium General w/ Heat Meter	324	45,967	3	108,019	0.1418
	2MGSG	Medium General Service	150	17,698	1	149,994	0.1180
	2MGSH	Medium General Service	26,820	3,270,990	151	177,616	0.1220
	2SGAH	Small General Space Heating	211	30,506	14	15,073	0.1446
	2SGHH	Small General w/ Heat Meter	56	6,747	4	13,994	0.1205
	2SGSG	Small General Service	0	229	1	49	4.6735
	2SGSH	Small General Service	14,796	1,912,911	680	21,759	0.1293
	ASH GROVE AGGREGATE INC		0	(10,060)	-		
	FUEL CLAUSE ACCRUAL		0	-			
	PROPERTY TAX SURCHARGE		0	-			
	UNBILLED REVENUE		-294	1 775			-0.0060
	TOTAL INDUSTRIAL		303,349	29,661,942	938	323,399	0.0978
PUBLIC STREET AND HIGHWAY LIGHTING (444)							
	2MLIL	Municipal St Lght Incandescent	102.91	19,708	10	10,291	0.1915
	2MLLL	Municipal St Light LED	104.534	110,059	3	34,845	1.0529
	2MLML	Municipal St Light Merc Vapor	660	159,827	19	34,737	0.2422
	2MLSL	Municipal St Light HP Sodium	8294.918	3,486,803	34	243,968	0.4204
	2MOSL	Municipal Ornamental St Light	1	1,548	1	1,000	1.5480
	2TSLM	Traffic Signal Lights	2374.25	1,514,824	12	197,854	0.6380
	ECKTS	Manual ECA Charge	0	-	-		
	PTKTS	Manual PTR Charge	97.359	0	-		0.0000
	FUEL CLAUSE ACCRUAL			-			
	PROPERTY TAX SURCHARGE						
	TOTAL PUBLIC STREET LIGHTS		11 635	5 292 769	79	147 278	0.4549
TOTAL BILLED			6,358,481	745,289,442	256,177	24,821	0.1172
TOTAL UNBILLED REVENUE			11 786	2 219 595	0		0.1883
TOTAL			6,370,267	747,509,037	256,177	24,867	0.1173

Kansas City Power & Light Company
SECTION 8: FINANCIAL AND OPERATING DATA
Sales of Electric ty by Rate Schedule

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SALES OF ELECTRICITY BY RATE SCHEDULE KANSAS ONLY CALENDAR YEARS 2013 2017

Revenue Classification	Number and Title of Rate Schedule		MWh Sold	Revenue	Average Number of Customers	KWh of Sales Per Customer	Revenue Per KWH Sold
SALES OF ELECTRICITY BY RATE SCHEDULE KANSAS 2017							
RESIDENTIAL SALES (440)							
	2ALDA	Area Lighting	1,010	389,299	1,824	554	0.3853
	2RO1A	Residential Standard	490	90,930	148	3,311	0.1856
	2RS1A	Residential Standard Service	1,776,282	245,619,972	156,922	11,320	0.1383
	2RS2A	Residential w/ Submeter Heat	10,605	1,325,083	945	11,222	0.1250
	2RS3A	Residential w/ Separate Ht Mtr	158,737	19,155,656	11,392	13,934	0.1207
	2RS6A	Residential w/ Elec Heat 1-Mtr	408,933	52,208,791	31,568	12,954	0.1277
	2RSDA	Residential Standard 3Ph AC	1,363	170,725	25	54,519	0.1253
	2RW6A	Res w/ Water & Space Ht 1-Mtr	324,127	40,040,308	25,304	12,809	0.1235
	2RW7A	Res w/ Water & Sep Space Heat	1,359	154,353	49	27,725	0.1136
	2TE1A	Residential Time-of-Day	653	87,103	49	13,317	0.1335
	ECKRS	Res Manual ECA Charge	0	-	-		
	EKRES	Res Manual EER Charge	0	-	-		
	PTKRS	Res Manual PTR Charge	0	-	-		
	FUEL CLAUSE ACCRUAL		0	-			
	PROPERTY TAX SURCHARGE		0	-			
	NET METERING		666				0.0000
	UNBILLED REVENUE		17,588	2,554,549			0.1452
	TOTAL RESIDENTIAL		2,701,812	361,796,769	228,226	11,838	0.1339
COMMERCIAL (442)							
	2ALDA	2ALDA-Area Lighting	0	-44	0	#DIV/0!	0.4310
	2ALDE	2ALDE-Area Lighting	1,968	588,994	718	2,741	0.2992
	2LGAE	2LGAE-Large General Space Heatin	644,496	59,082,021	294	2,192,164	0.0917
	2LGAF	2LGAF-Large General Space Heatin	45,902	3,528,840	4	11,475,581	0.0769
	2LGHE	2LGHE-Large General w/ Heat Meter	73,671	7,227,751	53	1,390,019	0.0981
	2LGSE	2LGSE-Large General Service	1,046,045	106,947,366	690	1,516,007	0.1022
	2LGSF	2LGSF-Large General Service	184,287	16,816,777	29	6,354,739	0.0913
	2LGSW	2LGSW-Large General Service	95,976	7,950,094	1	95,976,000	0.0828
	2LS1E	2LS1E-Off-Peak Lighting Service	44,712	3,729,159	1,651	27,082	0.0834
	2MGAE	2MGAE-Medium General Space Hea	116,596	12,014,924	442	263,792	0.1030
	2MGAF	2MGAF-Medium General Space Hea	2,733	385,676	5	546,524	0.1411
	2MGHE	2MGHE-Medium General w/ Heat Me	15,986	1,845,545	95	168,271	0.1154
	2MGSE	2MGSE-Medium General Service	589,410	71,181,838	3,304	178,393	0.1208
	2MGSF	2MGSF-Medium General Service	563	58,248	3	187,718	0.1034
	2MLSK	2MLSK-Commercial St Light HP Sod	2	797	1	1,911	0.4169
	2SGAE	2SGAE-Small General Space Heatin	22,652	2,955,338	1,190	19,035	0.1305
	2SGAF	2SGAF-Small General Space Heatin	1,365	239,243	5	272,919	0.1753
	2SGHE	2SGHE-Sma l General w/ Heat Meter	9,176	1,259,299	390	23,527	0.1372
	2SGSE	2SGSE-Small General Service	324,384	47,056,317	20,233	16,032	0.1451
	2SGSF	2SGSF-Small General Service	211	27,695	6	35,214	0.1311
	2SUSE	2SUSE-Small General Unmetered	2,709	529,879	934	2,900	0.1956
	2EV2E	2EV2E Electric Vehicle Charging Sta	270	36,578	63	4,285	0.1355
	2EV3E	2EV3E Electric Vehicle Charging Sta	54	7,862	4	13,443	0.1462
	2EVP2	2EVP2 Electric Vehicle Charging Sta	31	4,093	6	5,198	0.1312
	2EVP3	2EVP3 Electric Vehicle Charging Sta	7	944	1	6,723	0.1404
	FUEL CLAUSE ACCRUAL		0	0			
	PROPERTY TAX SURCHARGE		0	0			
	NET METERING		183				0.0000
	UNBILLED REVENUE		16 653	1 932 234			0.1160
	TOTAL COMMERCIAL		3,240,041	345,407,469	30,122	107,564	0.1066
INDUSTRIAL (442)							
	2LGAH	Large General Space Heating	20,034	1,945,501	10	2,003,396	0.0971
	2LGHH	Large General w/ Heat Meter	1,506	137,365	1	1,505,858	0.0912
	2LGSG	Large General Service	64,547	5,740,669	11	5,867,942	0.0889
	2LGSH	Large General Service	137,363	13,520,038	51	2,693,385	0.0984
	2LGSV	Large General Service	26,078	2,133,596	1	26,078,000	0.0818
	2MGAH	Medium General Space Heating	3,001	285,707	7	428,739	0.0952
	2MGHH	Medium General w/ Heat Meter	312	42,686	3	103,907	0.1369
	2MGSG	Medium General Service	163	18,972	1	163,463	0.1161
	2MGSH	Medium General Service	26,153	3,187,150	150	174,356	0.1219
	2SGAH	Small General Space Heating	771	146,622	14	55,056	0.1902
	2SGHH	Small General w/ Heat Meter	64	8,051	4	15,894	0.1266
	2SGSG	Small General Service	0	228	1	47	4.8528
	2SGSH	Small General Service	15,760	2,074,200	679	23,210	0.1316
	ASH GROVE AGGREGATE INC		0	(8,507)	-		
	FUEL CLAUSE ACCRUAL		0	-			
	PROPERTY TAX SURCHARGE		0	-			
	UNBILLED REVENUE		561	85,485			0.1523
	TOTAL INDUSTRIAL		296 313	29 317 761	933	317 592	0.0989
PUBLIC STREET AND HIGHWAY LIGHTING (444)							
	2MLIL	Municipal St Lght Incandescent	111	21,476	10	11,084	0.1938
	2MLLL	Municipal St Light LED	37	31,440	2	18,295	0.8593
	2MLML	Municipal St Light Merc Vapor	698	167,319	21	33,243	0.2397
	2MLSL	Municipal St Light HP Sodium	4,183	1,588,570	46	90,937	0.3798
	2MOSL	Municipal Ornamental St Light	-657	(263,581)	1	-657,250	0.4010
	2TSLM	Traffic Signal Lights	2,515	1,486,037	12	209,613	0.5908
	ECKTS	Manual ECA Charge	0	-	-		
	PTKTS	Manual PTR Charge	0	0	-		
	FUEL CLAUSE ACCRUAL		0	-			
	PROPERTY TAX SURCHARGE		0				
	TOTAL PUBLIC STREET LIGHTS		6,887	3,031,261	92	74,856	0.4402
TOTAL BILLED			6,210,251	734,980,992	259,373	23,943	0.1183
TOTAL UNBILLED REVENUE			34 802	4 572 268	0		0.1314
TOTAL			6,245,053	739,553,260	259,373	24,077	0.1184

Kansas City Power & Light Company
SECTION 8 FINANCIAL AND OPERATING DATA
Annual Payrolls by Primary Account
Source: Class Cost spreadsheet from Accounting

		Labor				
		Calendar Year Ending			Test Year Ending	
Primary Account	Description	2013	2014	2015	Year Prior to Test Year - September 2016	Test Year - September 2017
PRODUCTION EXPENSES						
500	SUPERVISION AND ENGINEER NG	8,201,572	3,081,213	4,371,998	6,040,148	7,038,210
501	FUEL	7,871,343	8,816,745	8,666,615	8,565,083	8,478,502
502	STEAM EXPENSES	11,258,647	11,359,011	12,354,910	10,283,266	9,919,558
503	STEAM FROM OTHER SOURCES	-	-	-	-	-
505	ELECTRIC EXPENSES TURBOGEN	5,718,641	5,898,855	6,050,475	5,500,233	5,190,870
506	MISC STEAM POWER EXPENSES	4,596,504	4,446,270	5,427,764	5,402,386	5,116,043
507	RENTS	-	-	512	756	-
510	SUPERVISION AND ENGINEER NG	4,166,002	3,196,721	3,479,545	3,637,871	4,780,646
511	MA NTENANCE OF STRUCTURES	1,206,247	1,206,270	1,631,737	1,675,798	1,461,931
512	MA NTENANCE OF BOILER PLANT	10,460,468	10,542,402	10,351,407	10,046,546	9,189,841
513	MA NTENANCE OF ELECTRIC PLANT	1,956,332	2,175,739	1,944,047	1,472,369	1,460,264
514	MA NTENANCE MISCELLANEOUS	51,303	37,602	66,735	51,253	28,984
517	NUCLEAR PROD. SUPERVISION & ENG.	6,222,682	5,955,904	6,223,950	6,324,567	6,489,724
518	NUCLEAR FUEL	-	-	-	-	-
519	COOLANTS AND WATER	2,027,126	1,819,616	2,191,265	2,222,291	2,194,082
520	STEAM EXPENSES	10,939,307	9,387,356	10,463,130	10,553,067	10,521,917
523	ELECTRIC EXPENSES	1,179,354	1,165,990	1,387,154	1,439,615	1,449,243
524	MISCELLANEOUS	11,634,403	16,132,892	12,133,890	14,750,903	11,554,545
525	RENTS	-	-	-	-	-
528	SUPERVISION & ENG NEERING	3,747,495	3,956,139	2,972,170	2,399,348	2,676,735
529	MA NTENANCE OF STRUCTURES	2,197,231	2,111,651	2,092,891	1,907,239	2,061,153
530	MA NTENANCE OF REACTOR PLANT	1,682,888	6,205,930	1,921,622	3,617,534	1,702,440
531	MA NTENANCE OF ELECTRIC PLANT	2,004,197	1,587,569	1,820,967	1,665,701	1,756,274
532	MA NTENANCE OF MISC. NUCLEAR PLANT	1,289,306	1,244,680	1,243,273	1,121,335	1,228,057
546	SUPERVISION & ENG NEERING	174,379	159,754	88,980	92,832	107,608
547	FUEL	47,254	33,857	26,368	30,604	55,066
548	GENERATION EXPENSES	923,307	556,779	681,377	742,159	671,976
549	MISC. OTHER POWER GEN. EXPENSES	386,469	437,888	346,225	382,498	368,647
550	RENTS	-	-	-	-	-
551	SUPERVISION & ENG NEERING	324,257	83,855	49,860	67,730	36,604
552	MA NTENANCE OF STRUCTURES	42,827	20,866	19,338	67,726	25,156
553	GENERATION AND ELECTRIC EQU P	838,907	902,210	923,221	1,173,995	1,255,867
554	MA NT. OF MISC. OTHER POWER GEN. PLANT	16,754	5,615	2,204	768	7,079
555	PURCHASED & NTERCHANGE POWER	-	-	-	-	-
556	SYSTEM CONTROL & LOAD DISPATCH	2,030,932	1,740,984	1,511,181	1,559,693	1,553,799
557	OTHER EXPENSES	4,428,220	5,454,399	4,076,331	4,896,648	5,397,256
TOTAL POWER PRODUCTION EXPENSES		107,624,353	109,724,761	104,521,140	107,691,963	103,778,078
TRANSMISSION EXPENSES						
560	OPERATION SUPERVISION & ENGRG	903,475	509,200	680,262	898,232	767,881
561	LOAD DISPATCHING	655,183	515,611	628,730	717,473	718,822
562	STATION EXPENSES	319,331	290,983	492,232	460,849	526,973
563	OVERHEAD L NE EXPENSES	5,631	3,859	8,975	9,734	6,055
564	UNDERGROUND LINE EXPENSES	-	-	-	-	-
565	TRANSMISSION OF ELEC BY OTHERS	-	-	-	-	-
566	MISC TRANSMISSION EXPENSES	947,778	877,106	967,910	1,132,135	1,243,882
567	RENTS	-	-	-	-	-
568	MA NTENANCE SUPERVISION & ENGRG	-	6,903	33,789	77,865	(39,207)
569	STRUCTURES	2,473	-	-	-	-
570	STATION EQU PMENT	428,150	502,687	528,523	500,493	443,920
571	OVERHEAD L NES	80,239	70,830	56,572	60,008	48,142
572	UNDERGROUND LINES	470	2,871	137	80	61
573	MISC TRANSMISSION PLANT MAINT.	3,225	283	-	190	230
575	POWER MARKET NG OPERATIONS	-	-	-	-	-
TOTAL TRANSMISSION EXPENSES		3,345,956	2,780,333	3,397,130	3,857,060	3,716,759

Filed in Accordance with K.A.R. 21-1-231-(c)(4)(H)(8)(v)

Kansas City Power & Light Company
SECTION 8 FINANCIAL AND OPERATING DATA
Annual Payrolls by Primary Account
Source: Class Cost spreadsheet from Accounting

		Labor				
		Calendar Year Ending			Test Year Ending	
Primary Account	Description	2013	2014	2015	Year Prior to Test Year - September 2016	Test Year - September 2017
DISTRIBUTION EXPENSES						
580	OPERATION SUPERVISION & ENGRG	3,116,883	1,415,421	2,592,282	4,366,846	3,084,782
581	LOAD DISPATCHING	516,273	730,301	1,032,065	789,012	483,145
582	STATION EXPENSES	77,119	83,233	67,146	72,142	64,791
583	OVERHEAD L NE EXPENSES	1,654,223	1,578,202	1,508,174	1,780,091	1,595,179
584	UNDERGROUND LINE EXPENSES	809,646	755,497	865,232	921,572	885,604
585	STREET LIGHT NG & SIGNAL SYSTEMS	22,962	31,977	8,172	5,354	47
586	METER EXPENSES	1,753,270	2,632,916	2,738,161	2,432,943	2,396,150
587	CUSTOMERS INSTALLATIONS	232,561	340,232	342,733	263,406	131,278
588	MISC DISTR BUTION EXPENSE	8,628,523	7,009,736	6,120,006	6,206,110	6,317,518
589	RENTS	6,259	5,848	5,211	5,698	11,466
590	MA NTENANCE SUPERVISION & ENRG	167,161	221,717	176,777	134,280	87,049
591	STRUCTURES	204,578	-	588	273	339
592	STATION EQU PMENT	552,173	599,730	590,576	654,514	647,233
593	OVERHEAD L NES	4,885,222	5,468,697	5,672,749	6,000,217	6,793,946
594	UNDERGROUND LINES	968,116	1,505,883	1,571,308	1,616,320	1,455,353
595	L NE TRANSFORMERS	241,092	-	160,997	242,674	262,614
596	STREET LIGHT NG & SIGNAL SYSTEMS	284,519	328,575	397,051	300,194	249,087
597	METERS	227,249	147,685	165,300	118,453	49,620
598	MISC DISTR BUTION PLANT	541,551	566,179	646,443	701,818	587,037
TOTAL DISTR BUTION EXPENSES		24,889,381	23,421,831	24,660,972	26,611,917	25,102,237
CUSTOMERS ACCOUNTS EXPENSE						
901	SUPERVISION	1,060,106	134,549	544,510	653,610	268,050
902	METER READ NG EXPENSES	964,585	763,677	820,482	850,794	801,363
903	CUST RECORDS & COLLECTION EXP	7,708,225	8,076,499	7,837,548	8,269,219	8,267,645
904	UNCOLLECTIBLE ACCOUNTS	-	-	-	-	-
905	MISC EXPENSE	299,023	602,893	466,992	248,070	331,133
TOTAL CUSTOMERS ACCOUNTS EXPENSE		10,031,939	9,577,618	9,669,531	10,021,693	9,668,191
CUSTOMERS SERVICES & INFO EXP						
907	CUSTOMER SERVICE SUPERVISION EXPENSE	64,586	14,952	106,212	96,267	94,797
908	CUSTOMER ASSISTANCE EXPENSE	196,777	338,302	618,091	793,728	801,181
908	PUBLIC NFORMATION	-	-	-	-	-
909	INSTRUCTIONAL ADVERTISING	31,186	159	-	-	-
910	MISCELLANEOUS CUSTOMER SERVICE EXPENSE	695,485	619,625	661,315	794,696	585,288
TOTAL CUSTOMER SERVICES & INFO EXP		988,034	973,039	1,385,619	1,684,691	1,481,266
SALES EXPENSE						
911	SUPERVISION EXPENSE	-	-	-	-	-
912	DEMONSTRATION & SELLING EXP - RETA L	-	-	-	-	-
912	DEMONSTRATION & SELLING EXP - WHOLESALE	-	-	-	-	-
912	DEMONSTRATION & SELLING EXP - MISC.	250,483	258,369	328,127	342,504	390,420
913	ADVERTIS NG	-	-	(2,819)	(150)	-
916	MISC SALES EXPENSE	61,099	-	-	-	-
TOTAL SALES EXPENSE		311,583	258,369	325,308	342,353	390,420
ADMINISTRATIVE & GENERAL EXPENSES						
920	SALARIES	35,056,035	29,983,685	32,065,243	33,938,023	33,721,308
921	OFFICE EXPENSE	48,125	(267)	15,237	5,314	1,737
922	ADM N EXP TRANSFERRED - CR	(570,412)	(630,537)	(581,504)	(742,131)	(714,975)
923	OUTSIDE SEVICES	-	-	-	-	-
924	PROPERTY INSURANCE	(19)	-	-	-	-
925	INJURIES & DAMAGES	(29,118)	7,455	22,758	16,347	6,754
926	EMPLOYEE BENEFITS	(2,845,794)	(778,756)	(2,000,948)	(3,412,303)	(3,149,677)
928	REGULATORY EXPENSES	685,207	1,254,091	1,724,600	1,078,718	1,373,185
929	DUPLICATE CHARGES	-	-	-	-	-
930.1	GENERAL ADVERTIS NG	20,638	-	-	-	-
930 2	MISCELLANEOUS EXPENSE	74,278	55,360	7,874	20,923	4,861
931	RENTS	-	-	-	-	-
933	FLEET EXPENSE; TRANSPORTATION & O SERIES	-	-	-	-	-
935	MA NTENANCE OF GENERAL PLANT	127,799	172,699	211,479	273,025	123,240
TOTAL ADMINISTRATIVE & GENERAL EXPENSE		32,566,740	30,063,732	31,464,738	31,177,917	31,366,433
TOTAL LABOR CHARGED TO O&M EXPENSES		179,757,985	176,799,683	175,424,438	181,387,593	175,503,385
OTHER ACCOUNTS						
PLANT (CWIP) 107XXX		54,785,524	61,301,294	61,205,729	57,494,153	63,475,930
REMOVALS (RWIP) 108XXX		4,773,433	5,333,163	4,584,577	4,832,041	5,288,767

Kansas City Power & Light Company
SECTION 8 FINANCIAL AND OPERATING DATA
Annual Payrolls by Primary Account
Source: Class Cost spreadsheet from Accounting

Primary Account	Description	Labor: Calendar Year Ending 2013	2014	2015	Test Year Ending: Year Prior to Test Year - September 2016	Test Year - September 2017
OTHER BALANCE SHEET ACCOUNTS						
1201XX	NUCLEAR FUEL	176,227	377,560	154,650	152,559	73,050
1516XX	UNIT TRAIN	1,087,972	32,299	51,674	82,384	93,632
1516XX	JO NT VENTURE ADJ. TO UNIT TRA NS	-	-	-	-	-
185XXX	TEMP FACILIT ES	-	-	-	-	-
1860XX	DEFERRED DEBITS	-	-	-	-	-
1861XX	BILLING WORKORDERS	1,343,820	445,654	747,316	447,209	1,583,555
1862XX	MISCELLANEOUS WORKORDERS	63,612	148,751	129,044	163,590	73,277
1862XX	NON-UT LITY CWIP & RWIP	129,378	12,725	10,526	4,025	3,714
186299 999XXX	SUSPENSE	(601)	1,500	215	(131)	15,921
163	CLEAR NGS - STORES	-	-	-	-	-
184	CLEAR NGS - OVERHEADS	-	-	-	-	-
188001	R&D EXPENSE	-	-	-	-	-
232006	CONTRACTOR RETENTIONS	-	-	-	-	-
232401	ENVIRONMENTAL ACCRUALS	-	-	-	-	-
18244X	DEFERRED CUSTOMER PROGRAMS	52,098	58,717	89	89	-
182497	ECONOMIC REL EF P LOT PROGRAM	-	-	-	-	-
182492 & 3	KS & MO TRANSITION COSTS	-	-	-	-	-
182502	Iatan 2 Constr Acctg	-	-	-	-	-
186826	SmartGrid Dem Grant Deferred	130,507	-	-	-	-
	Miscellaneous Balance Sheet Activity	302	(302)	-	-	13
TOTAL OTHER BALANCE SHEET		2,983,315	1,076,905	1,093,513	849,726	1,843,162
OTHER INCOME/DEDUCTIONS						
8171XX 8182XX	NON-UT LITY EXPENSES	249,008	425,399	629,474	519,469	536,347
8261XX	DONATIONS	472,954	587,496	537,002	509,443	443,396
8264XX	CIVIC & POLITICAL	223,750	181,739	132,740	159,740	157,449
8265XX	OTHER NCLUDING MERGER ACTIVITIES	20,983	8,992	9,671	3,535	4,449,677
831018	INTEREST ON MISCELLANEOUS ACCOUNTS	-	-	-	-	-
TOTAL OTHER INCOME/DECUCTIONS		966,695	1,203,626	1,308,888	1,192,187	5,586,868
GRAND TOTAL		243,266,952	245,714,671	243,617,146	245,755,701	251,698,112

Note This schedule includes total compensation (ie. additional compensation); and therefore will not tie to payroll adjustment CS-50 in this case.

SECTION 9
TEST YEAR/ PRO FORMA INCOME STATEMENTS

Filed in Accordance with K A R 21-1-231-(c)(4)(I)

CONFIDENTIAL

Kansas City Power & Light Company
2018 RATE CASE - DIRECT
Kansas Jurisdiction
TY 9/30/17 K&M 6/30/18

12 Month Revenues and O & M Expenses - Schedule 9

Line No.	Account No.	Description	Per Books Test Year	Rate Case Adj	Adjusted Balance	Juris Factor #	Juris Allocator	Electric Juris Adjusted Balance
	A	B	C	D	E	F	G	H
1		**ELECTRIC - RETAIL SALES**						
2	400	Missouri (excluding GRT)	922,340,199	0	922,340,199	100% MO	0.0000%	0
3		Gross Receipts Tax in MO Revenue	72,139,181	0	72,139,181	100% MO	0.0000%	0
4		Amort of Off Syst Sales Margin Rate Refund	758,974	0	758,974	100% MO	0.0000%	0
5		TOTAL MISSOURI	995,238,354	0	995,238,354			0
6		Kansas	737,867,916	(29,481,934)	708,385,982	100% KS	100.0000%	708,385,982
7		**TOTAL RETAIL SALES**	**1,733,106,270**	**(29,481,934)**	**1,703,624,336**			708,385,982
8		**MISCELLANEOUS REVENUE**						
9	450	Forfeited Discounts - MO	2,178,591	0	2,178,591	100% MO	0.0000%	0
10		Forfeited Discounts - KS	1,598,065	96,517	1,694,582	100% KS	100.0000%	1,694,582
11	451	Miscellaneous Services - MO	566,867	0	566,867	100% MO	0.0000%	0
12		Miscellaneous Services - KS	399,838	0	399,838	100% KS	100.0000%	399,838
13		Miscellaneous Services - Allocated - Dist	(36,449)	0	(36,449)	Dist Plt	44.3024%	(16,148)
14	454	Rent from Electric Property - MO	1,911,266	0	1,911,266	100% MO	0.0000%	0
15		Rent from Electric Property - KS	1,963,695	0	1,963,695	100% KS	100.0000%	1,963,695
16		Rent from Electric Property - Allocated - Prod	28,625	0	28,625	D1	47.0659%	13,473
17		Rent from Electric Property - Allocated - Trans	6,785	(6,785)	0	D1	47.0659%	0
18		Rent from Electric Property - Allocated - Dist	0	0	0	Dist Plt	44.3024%	0
19	456	456100 Transmission for Others	16,078,018	(16,078,018)	0	D1	47.0659%	0
20		Other Elec Revenues - Allocated - Transmission	(15,724)	0	(15,724)	D1	47.0659%	(7,401)
21		Other Elec Revenues - MO	811,376	0	811,376	100% MO	0.0000%	0
22		Other Elec Revenues - KS	137,920	0	137,920	100% KS	100.0000%	137,920
23		Other Elec Revenues - Allocated - Dist	0	0	0	Dist Plt	44.3024%	0
24		**TOTAL MISCELLANEOUS REVENUE**	**25,628,873**	**(15,988,286)**	**9,640,587**			**4,185,959**
25		**BULK POWER SALES (BPS)**						
26	447	Firm Bulk Sales (Capacity & Fixed)	2,947,598	0	2,947,598	E1	43.5895%	1,284,843
27		Firm Bulk Sales (Energy)	113,026,646	0	113,026,646	E1	43.5895%	49,267,750
28		Other Miscellaneous & Adjustments	0	0	0	E1	43.5895%	0
29		Non-firm Sales (margin on sales) **	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted] **
30		Non-firm Sales (cost of sales & other) **	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted] **
31		**TOTAL BULK POWER SALES**	**115,974,244**	**0**	**115,974,244**			**50,552,593**
32		**SALES FOR RESALE (FERC JURIS CUST)**						
33	447	FERC JURIS WHOLESALE FIRM POWER	0	0	0	NonJur/Wh	0.0000%	0
34		TRANSMISSION FOR FERC WHSLE FIRM POWER		0	0	NonJur/Wh	0.0000%	0
35		**TOTAL SALES FOR RESALE**	**0**	**0**	**0**			**0**
36	449	**Other Sales Revenue**		128,376	128,376	Dist Plt	44.3024%	56,874
37	449.1	**Prov for Rate Refund Riders** **	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted] **
38								
39		**TOTAL ELECTRIC OPERATING REVENUE**	**1,875,647,402**	**(45,341,844)**	**1,830,305,558**			**763,181,408**
40		**POWER PRODUCTION EXPENSES**						
41		**STEAM POWER GENERATION**						
42		**STEAM POWER OPERATION**						
43	500.000	Prod Steam Operation- Suprv & Engineering	8,140,216	(27,419)	8,112,797	D1	47.0659%	3,818,361
44	500.000	Steam Prod Oper-Iat 1 & 2 -100% MO	393,388	0	393,388	100% MO	0.0000%	0
45	500.000	Steam Prod Oper-Iat 2 -100% KS	(144,493)	0	(144,493)	100% KS	100.0000%	(144,493)
46	501.000	Fuel Expense						
47		Labor	8,478,502	181,279	8,659,781	E1	43.5895%	3,774,755
48		Fuel Handling - Non-labor	4,125,041	0	4,125,041	E1	43.5895%	1,798,085
49		Fuel Expense-Coal & Freight	198,089,643	0	198,089,643	E1	43.5895%	86,346,285
50		100% MO STB- (Surface Trsp Board)	(101,759)	0	(101,759)	100% MO	0.0000%	0
51		100%-KS-STB- (Surface Trsp Board)	0	0	0	100% KS	100.0000%	0
52		Fuel Expense-Oil	3,165,360	0	3,165,360	E1	43.5895%	1,379,765
53		Fuel Expense- Gas	2,008,091	0	2,008,091	E1	43.5895%	875,317
54		Fuel Expense-Residual	1,497,246	0	1,497,246	E1	43.5895%	652,642
55		Additives, incl Ammonia, Limestone & Oth	5,957,547	0	5,957,547	E1	43.5895%	2,596,865
56		Fuel Expense - Unit Train Depreciation	592,500	2,385,062	2,977,562	D1	47.0659%	1,401,416
57	502.000	Steam Operating Expense	15,840,475	212,131	16,052,606	D1	47.0659%	7,555,303
58	502.000	Steam Operating Expense-Iat 2-100% MO	0	0	0	100% MO	0.0000%	0
59	502.000	Steam Operating Expense-Iat 2-100% KS	0	0	0	100% KS	100.0000%	0
60	505.000	Steam Operating Electric Expense	6,718,074	111,008	6,829,082	D1	47.0659%	3,214,169
61	505.000	Steam Operating Elec Exp-Iat 2-100% MO	0	0	0	100% MO	0.0000%	0
62	505.000	Steam Operating Elec Exp-Iat 2-100% KS	0	0	0	100% KS	100.0000%	0
63	506.000	Miscl Other Power Expenses	10,568,055	(339,846)	10,228,209	D1	47.0659%	4,813,999
64	506.000	Miscl Other Power Exp-Iat 2-100% MO	471,848	0	471,848	100% MO	0.0000%	0
65	506.000	Miscl Other Power Exp-Iat 2-100% KS	548,080	0	548,080	100% KS	100.0000%	548,080
66	507.000	Steam Operating Exp - Rents	288,392	0	288,392	D1	47.0659%	135,734
67	507.000	Steam Operating Exp-Rents-Iat 2-100% MO	0	0	0	100% MO	0.0000%	0
68	507.000	Steam Operating Exp-Rents-Iat 2-100% KS	0	0	0	100% KS	100.0000%	0
69	509.000	Allowances						
70		KS REC's	0	0	0	100% KS	100.0000%	0
71		NOX/Other Allowances-Allocated	1,282	0	1,282	E1	43.5895%	559
72		Amort of SO2 Allowances-MO	(2,302,166)	0	(2,302,166)	100% MO	0.0000%	0
73		Amort of SO2 Allowances-KS	(1,681,238)	0	(1,681,238)	100% KS	100.0000%	(1,681,238)
74		**TOTAL STEAM OPERATION**	**262,654,084**	2,522,215	265,176,299			117,085,604

Kansas City Power & Light Company
2018 RATE CASE - DIRECT
Kansas Jurisdiction
TY 9/30/17 K&M 6/30/18

12 Month Revenues and O & M Expenses - Schedule 9

Line No.	Account No.	Description	Per Books Test Year	Rate Case Adj	Adjusted Balance	Juris Factor #	Juris Allocator	Electric Juris Adjusted Balance
75		**STEAM POWER OPERATION**						
76	510.000	Steam Maintenance Suprv & Engineering	7,102,017	102,213	7,204,230	D1	47.0659%	3,390,736
	510.000	Steam Mtce Suprv & Eng-Iat 2-100% MO	0	0	0	100% MO	0.0000%	0
77	510.000	Steam Mtce Suprv & Eng-Iat 2-100% KS	0	0	0	100% KS	100.0000%	0
78	511.000	Maintenance of Structures	7,404,691	31,264	7,435,955	D1	47.0659%	3,499,799
	511.000	Maintenance of Structures-Iat 2-100% MO	0	0	0	100% MO	0.0000%	0
79	511.000	Maintenance of Structures-Iat 2-100% KS	0	0	0	100% KS	100.0000%	0
80	512.000	Maintenance of Boiler Plant		0				
81		Non-Labor	25,101,798	0	25,101,798	D1	47.0659%	11,814,387
82		Labor	9,189,841	196,526	9,386,367	D1	47.0659%	4,417,778
83		Steam Prod Mtce- Iat 1 & 2-100% MO	292,105	0	292,105	100% MO	0.0000%	0
84		Steam Prod Mtce-Iat 2-100% KS	0	0	0	100% KS	100.0000%	0
85	513.000	Maintenance of Electric Plant	4,308,996	31,228	4,340,224	D1	47.0659%	2,042,765
	513.000	Maintenance of Elec Plant-Iat 2-100% MO	154,078	0	154,078	100% MO	0.0000%	0
86	513.000	Maintenance of Elec Plant-Iat 2-100% KS	0	0	0	100% KS	100.0000%	0
87	514.000	Maintenance of Miscellaneous Steam Plant	350,019	620	350,639	D1	47.0659%	165,031
	514.000	Mtce of Misc Steam Plant-Iat 2-100% MO	0	0	0	100% MO	0.0000%	0
88	514.000	Mtce of Misc Steam Plant-Iat 2-100% KS	0	0	0	100% KS	100.0000%	0
89		**TOTAL STEAM MAINTENANCE**	53,903,545	361,851	54,265,396			25,330,497
90		**TOTAL STEAM POWER GENERATION EXPENSE**	316,557,629	2,884,066	319,441,695			142,416,101
91		**NUCLEAR POWER GENERATION**						
92		**NUCLEAR OPERATION**						
93	517.000	Prod Nuclear Operation- Superv & Engineer	7,590,908	138,784	7,729,692	D1	47.0659%	3,638,049
94	518.000	Nuclear Fuel Expense						
95		Nuclear Fuel - Net Amortizarion	30,725,326	0	30,725,326	E1	43.5895%	13,393,016
96		Prod Nuclear-Disposal Costs		0	0	E1	43.5895%	0
97		KS DOE Refund (100% KS)	0	0	0	E1	43.5895%	0
98		Cost of Oil	142,648	0	142,648	E1	43.5895%	62,180
99		Labor	0	0		E1	43.5895%	0
100	519.000	Coolants and Water	2,903,445	818,415	3,721,860	D1	47.0659%	1,751,727
101	520.000	Steam Expense	13,854,436	225,013	14,079,449	D1	47.0659%	6,626,619
102	523.000	Electric Expense	1,408,063	30,992	1,439,055	D1	47.0659%	677,304
103	524.000	Miscellaneous Nuclear Power Exp						
104		Misc. Nuclear Power Exp-100% KS	0	0	0	100% KS	100.0000%	0
105		Decommissioning-Missouri	1,281,264	0	1,281,264	100% MO	0.0000%	0
106		Decommissioning-Kansas	2,036,230	0	2,036,230	100% KS	100.0000%	2,036,230
107		Decommissioning-FERC	38,753	0	38,753	NonJur/Wh	0.0000%	0
108		Refueling Outage Amortization	184,776	121,978	306,754	D1	47.0659%	144,377
109		Refueling Outage Amortization - MO only	250,859	(201,816)	49,043	100% MO	0.0000%	0
110		Misc. Nucl Power Exp-Other-Alloc	22,870,983	194,818	23,065,801	D1	47.0659%	10,856,127
111	525.000	Rents	0	0	0	D1	47.0659%	0
112		**TOTAL NUCLEAR OPERATION**	83,287,691	1,328,184	84,615,875			39,185,628
113		**NUCLEAR MAINTENANCE**						
114	528.000	Prod Nuclear Maint- Suprv & Engineer	5,100,696	57,242	5,157,938	D1	47.0659%	2,427,630
115	529.000	Prod Nuclear Maint- Maint of Structures	2,420,831	44,078	2,464,909	D1	47.0659%	1,160,132
116	530.000	Prod Nuclear Maint- Maint Reactor Plant						
117		Refueling Outage Amortization	1,361,937	256,292	1,618,229	D1	47.0659%	761,634
118		Refueling Outage Amortization - MO only	1,049,271	(605,449)	443,822	100% MO	0.0000%	0
119		Maint Reactor Plant - Other	9,168,318	13,114	9,181,432	D1	47.0659%	4,321,324
120	531.000	Prod Nuclear Mtce - Electric Plant	4,019,234	37,558	4,056,792	D1	47.0659%	1,909,366
121	532.000	Prod Nuclear Maint- Maint of Miscl Plant	2,740,805	26,262	2,767,067	D1	47.0659%	1,302,345
122		**TOTAL NUCLEAR MAINTENANCE**	25,861,092	(170,903)	25,690,189			11,882,430
123		**TOTAL NUCLEAR POWER GENERATION**	109,148,783	1,157,281	110,306,064			51,068,058
124		**OTHER POWER GENERATION**						
125		**OTHER POWER OPERATION**						
126	546.000	Prod Turbine Oper-Supr & Engineering	116,079	(4,423)	111,656	D1	47.0659%	52,552
127	547.000	Other PowerOperation- Fuel Expense						
128		Labor	55,066	1,178	56,244	E1	43.5895%	24,516
129		Fuel Handling (non-labor)	62,930	0	62,930	E1	43.5895%	27,431
130		Other Fuel Expense - Oil	526,759	0	526,759	E1	43.5895%	229,612
131		Other Fuel Expense - Gas	6,279,967	0	6,279,967	E1	43.5895%	2,737,406
132		Other Fuel Expense - Hedging - MO	13,790	0	13,790	100% MO	0.0000%	0
133		Additives	20,929	0	20,929	E1	43.5895%	9,123
134	548.000	Other Power Generation Expense	902,476	14,370	916,846	D1	47.0659%	431,522
135	549.000	Misc Other Power Generation Expense	1,298,562	7,884	1,306,446	D1	47.0659%	614,891
136	550.000	Other Generation Rents	0	0	0	D1	47.0659%	0
137		**TOTAL OPERATION - OP**	9,276,558	19,009	9,295,567			4,127,052
138		**OTHER POWER MAINTANENCE**						
139	551.000	Other Maint-Supr Eng. Struct Gen & Misc.	37,866	783	38,649	D1	47.0659%	18,190
140	552.000	Other General Maintenance of Structures	167,873	538	168,411	D1	47.0659%	79,264
141	553.000	Other General Maint of General Plant	2,299,364	26,857	2,326,221	D1	47.0659%	1,094,857
142	554.000	Other Gen Maint Miscl. Other General Plant	33,312	151	33,463	D1	47.0659%	15,750
143		**TOTAL MAINTANENCE - OP**	2,538,415	28,329	2,566,744			1,208,061
144		**TOTAL OTHER POWER GENERATION**	11,814,973	47,338	11,862,311			5,335,113

Filed in Accordance with K A R 21-1-231-(c)(4)(I)

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Line No.	Account No.	Description	Per Books Test Year	Rate Case Adj	Adjusted Balance	Juris Factor #	Juris Allocator	Electric Juris Adjusted Balance
145		**OTHER POWER SUPPLY EXPENSES**						
146	555.000	Purchased Power						
147		Purchased Power-Energy	144,601,307	0	144,601,307	E1	43.5895%	63,030,987
148		Purchased Power-Capacity (Demand)	0	0	0	E1	43.5895%	0
149		Purch Pwr Energy Solar Contrct (100% MO)	0	0	0	100% MO	0.0000%	0
150		Solar Renew Energy Credits (100% MO)	0	0	0	100% MO	0.0000%	0
151	556.000	System Control and Load Dispatch	1,838,487	33,228	1,871,715	D1	47.0659%	880,940
152	557.000	Other Expenses	8,320,817	(305,524)	8,015,293	D1	47.0659%	3,772,470
153	557.100	373ECATRUE 11200	(2,465,719)	2,465,719	0	100% KS	100.0000%	0
154	557.100	373KCPFAC 10200	(11,373,112)	0	(11,373,112)	100% MO	0.0000%	0
155		**TOTAL OTHER POWER SUPPLY EXPENSES**	**140,921,780**	**2,193,423**	**143,115,203**			**67,684,396**
156		**TOTAL POWER PRODUCTION EXPENSES**	**578,443,165**	**6,282,108**	**584,725,273**			**266,503,668**
157		**TRANSMISSION EXPENSES**						
158		**OPERATION - TRANSMISSION EXP.**						
159	560.000	Transmission Operation Suprv and Engrg	824,635	(688,667)	135,968	D1	47.0659%	63,995
160	561.000	561.4 & 561.8 Transmission Operation- Load Dispatch	7,053,685	(5,054,885)	1,998,800	E1	43.5895%	871,267
161	561.000	Other 561 Transmission Operation- Load Dispatch	0	15,351	15,351	E1	43.5895%	6,691
161	562.000	Transmission Operation- Station Expenses	741,821	(610,098)	131,723	D1	47.0659%	61,997
162	563.000	Transmission Operation-Overhead Line Expense	312,482	(257,803)	54,679	D1	47.0659%	25,735
163	564.000	Trans Oper-Underground Line Expense	13,000	0	13,000	D1	47.0659%	6,119
164	565.000	Transmission of Electricity by Others	64,874,976	(45,957,916)	18,917,060	E1	43.5895%	8,245,852
165	565.100	Trans Op Trans Rider all KS 11200	(391,252)	391,252	0	100% KS	100.0000%	0
166	566.000	Miscl. Transmission Expense	2,920,641	(2,405,139)	515,502	D1	47.0659%	242,626
167	567.000	Transmission Operation Rents	2,423,612	(2,423,612)	0	D1	47.0659%	0
168	575.000	Regional Transmission Operation	6,646,953	(5,370,156)	1,276,797	E1	43.5895%	556,549
169		**TOTAL OPERATION - TRANSMISSION EXP.**	**85,420,553**	**(62,361,673)**	**23,058,880**			**10,080,830**
170		**MAINTENANCE - TRANSMISSION EXP.**						
171	568.000	Transmission Maint-Suprv and Engrg	(80,246)	66,064	(14,182)	D1	47.0659%	(6,675)
172	569.000	Transmission Maintenance of Structures	0	0	0	D1	47.0659%	0
173	570.000	Transmission Maintenance of Station Equipment	644,576	(530,173)	114,403	D1	47.0659%	53,845
174	571.000	Transmission Maintenance of Overhead Lines	2,335,190	(1,926,562)	408,628	D1	47.0659%	192,324
175	572.000	Trans Maintenance of Underground Lines	5,624	(4,640)	984	D1	47.0659%	463
176	573.000	Trans Maintenance of Miscl. Trans Plant	5,821	(4,802)	1,019	D1	47.0659%	480
177	576.000	Transmission Maintenance-Comp	0	0	0	D1	47.0659%	0
178		**TOTAL MAINTENANCE - TRANSMISSION EXP.**	**2,910,965**	**(2,400,113)**	**510,852**			**240,437**
179		**TOTAL TRANSMISSION EXPENSES**	**88,331,518**	**(64,761,786)**	**23,569,732**			**10,321,267**
180		**DISTRIBUTION EXPENSES**						
181		**OPERATION - DIST. EXPENSES**						
182	580.000	Distribution Operation - Supr & Engineering	3,461,005	(244,736)	3,216,269	Dist Plt	44.3024%	1,424,883
183	581.000	Distribution Operation - Load Dispatching	492,771	10,332	503,103	Dist Plt	44.3024%	222,887
184	582.000	Distribution Operation - Station Expense	139,089	1,386	140,475	362	37.8780%	53,209
185	583.000	Dist Operation Overhead Line Expense	2,249,576	34,006	2,283,582	365	43.3827%	990,680
186	584.000	Dist Operation Underground Line Expense	4,033,947	18,831	4,052,778	367	47.2175%	1,913,620
187	585.000	Distrb Oper Street Light & Signal Expense	49	0	49	373	52.6596%	26
188	586.000	Distribution Operation Meter Expense	2,629,165	51,242	2,680,407	370	47.8273%	1,281,966
189	587.000	Distrb Operation Customer Install Expense	137,140	2,807	139,947	371	31.4016%	43,946
190	588.000	Dist Operation Miscl Distribution Expense	13,937,944	122,055	14,059,999	Dist Plt	44.3024%	6,228,913
191	589.000	Distribution Operations Rents	79,453	245	79,698	Dist Plt	44.3024%	35,308
192		**TOTAL OPERATION - DIST. EXPENSES**	**27,160,139**	**(3,832)**	**27,156,307**			**12,195,438**
193		**MAINTENANCE - DISTRIB. EXPENSES**						
194	590.000	Distribution Maint-Suprv & Engineering	91,832	1,862	93,694	Dist Plt	44.3024%	41,509
195	591.000	Distribution Maintenance-Structures	681	7	688	361	43.2654%	298
196	592.000	Distribution Maintenance-Station Equipment	877,453	13,841	891,294	362	37.8780%	337,604
197	593.000	Distribution Maintenance-Overhead lines	21,475,027	144,430	21,619,457	365	43.3827%	9,379,104
198	593.000	Distribution Maint. Overhead lines- 100% MO	0	0	0	100% MO	0.0000%	0
199	593.000	Dist. Maint Overhead Lines Veg.Mgmt 100% MO	0	0	0	100% MO	0.0000%	0
200	594.000	Distrib Maint-Maintenance Underground Lines	1,957,087	31,123	1,988,210	367	47.2175%	938,783
201	594.000	Dist Maint. Underground Lines 100% MO	0	0	0	100% MO	0.0000%	0
202	595.000	Distrib Maint-Maintenance Line Transformer	325,895	5,616	331,511	368	43.2615%	143,417
203	596.000	Distrib Maint- Maintenance St Lights/Signal	672,414	5,327	677,741	373	52.6596%	356,896
204	597.000	Distrib Maint-Maintenance of Meters	188,552	1,061	189,613	370	47.8273%	90,687
205	598.000	Distrib Maint-Maint Miscl Distribution Plant	2,098,872	115,135	2,214,007	Dist Plt	44.3024%	980,858
206		**TOTAL MAINTENANCE - DISTRIB. EXPENSES**	**27,687,813**	**318,402**	**28,006,215**			**12,269,155**
207		**TOTAL DISTRIBUTION EXPENSES**	**54,847,952**	**314,570**	**55,162,522**			**24,464,592**
208		**CUSTOMER ACCOUNTS EXPENSE**						
209	901.000	Cust Acct-Suprv Meter Read Collection Miscl	304,595	10,787	315,382	C1	47.3951%	149,476
210	902.000	Cust Accts Meter Reading Expense	4,653,849	614,072	5,267,921	C1	47.3951%	2,496,736
211	903.000	Customer Accts Records and Collection	13,933,048	261,555	14,194,603	C1	47.3951%	6,727,546
212	903.000	Cust Accts-Interest on Deposits - MO	0	196,733	196,733	100% MO	0.0000%	0
213	903.000	Cust Accts-Interest on Deposits - KS	0	29,306	29,306	100% KS	100.0000%	29,306
214	904.000	Uncollectible Accounts-MO 100%	0	5,462,528	5,462,528	100% MO	0.0000%	0
215	904.000	Uncollectible Accts-KS 100%	0	2,282,284	2,282,284	100% KS	100.0000%	2,282,284
216	905.000	Miscellaneous Customer Accts Expense	765,547	2,926,515	3,692,062	C1	47.3951%	1,749,856
217		**TOTAL CUSTOMER ACCOUNTS EXPENSE**	**19,657,039**	**11,783,780**	**31,440,819**			**13,435,205**

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Line No.	Account No.	Description	Per Books Test Year	Rate Case Adj	Adjusted Balance	Juris Factor #	Juris Allocator	Electric Juris Adjusted Balance
218		**CUSTOMER SERVICE & INFO EXP**						
219	907.000	Customer Service Suprv	94,797	2,027	96,824	C1	47.3951%	45,890
220	908.000	Customer Assistance Expense						
221		Customer Assistance Exp-100% KS	(373)	173,685	173,312	100% KS	100.0000%	173,312
222		Customer Assistance Exp-100% MO	10,195,426	0	10,195,426	100% MO	0.0000%	0
223		Customer Assistance Expense-Allocated	(415,815)	17,133	(398,682)	C1	47.3951%	(188,956)
224	908.100	Cust Assist Exp - Exp Rider 343 MEIAA4 100% MO	2,780,110	0	2,780,110	100% MO	0.0000%	0
225	908.500	Cust Assist Exp - MEEIA 100% MO	25,322,195	0	25,322,195	100% MO	0.0000%	0
226	908.500	Cust Assist Exp - KEEIA 100% KS	63,867	0	63,867	100% KS	100.0000%	63,867
227	909.000	Information and Instruction Advertising						
228		Information and Instruction Advertising	133,961	(600)	133,361	C1	47.3951%	63,207
229		Inform & Instructional Advertis- 100% MO	50,986	0	50,986	100% MO	0.0000%	0
230	910.000	Misc Customer Accounts and Info Exp						
231		Misc Cust Accts & Info Exp-Allocated	1,169,455	321,201	1,490,656	C1	47.3951%	706,498
232		Misc Cust Accts & Info Exp-100% MO	7,753,859	0	7,753,859	100% MO	0.0000%	0
233		**TOTAL CUSTOMER SERVICE & INFO EXP**	**47,148,468**	**513,446**	**47,661,914**			**863,818**
234		**SALES EXPENSES**						
235	911.000	Sales Supervision	0	0	0	C1	47.3951%	0
236	912.000	Sales Demonstration and Selling	528,411	(1,211)	527,200	C1	47.3951%	249,867
237	913.000	Sales Advertising Expense	0	0	0	C1	47.3951%	0
238	916.000	Miscellaneous Sales Expense	0	0	0	C1	47.3951%	0
239		**TOTAL SALES EXPENSES**	**528,411**	**(1,211)**	**527,200**			**249,867**
240		**ADMIN. & GENERAL EXPENSES**						
241		**OPERATION - ADMIN. & GENERAL EXP**						
242	920.000	Admin & Gen-Administrative Salaries						
243		Admin & Gen-Admin Salaries - Allocated	38,692,228	(4,470,594)	34,221,634	Sal&Wg	46.4069%	15,881,214
244		Admin & Gen-Admin. Salaries- 100% MO	(28,240)	0	(28,240)	100% MO	0.0000%	0
245		Admin & Gen- Admin. Salaries- 100% KS	1,220,486	(1,220,486)	0	100% KS	100.0000%	0
246	921.000	Admin & General Off Supply						
247		Admin & General Off Supply- Allocated	(993,178)	5,786	(987,392)	E1	43.5895%	(430,399)
248		Admin & General Off Supply- 100% MO	(14,653)	0	(14,653)	100% MO	0.0000%	0
249		Admin & General Off Supply- 100% KS	448	(11,118)	(10,670)	100% KS	100.0000%	(10,670)
250		Settlement - Misc Issues for ER-xxxx-xxxx	0	0	0	E1	43.5895%	0
251	922.000	Admin Expense Transfer Credit	(15,373,708)	(6,985,142)	(22,358,850)	E1	43.5895%	(9,746,111)
252	922.001	Admin Expense Transfer Credit 2	0	0	0	E1	43.5895%	0
253	923.000	Outside Services Employed						
254		Outside Services Employed-Allocated	13,832,966	1,847,413	15,680,379	E1	43.5895%	6,834,999
255		Outside Services-100 % MO	(17,387)	0	(17,387)	100% MO	0.0000%	0
256		Outside Services- 100% KS	84,280	1,260,555	1,344,835	100% KS	100.0000%	1,344,835
257	924.000	Property Insurance	4,056,361	25,871	4,082,232	PTD	46.2712%	1,888,898
258	925.000	Injuries and Damages	18,415,953	(11,082,275)	7,333,678	Sal&Wg	46.4069%	3,403,336
259	926.000	Employee Pensions and Benefits						
260		Employee Pensions	50,909,432	(3,172,643)	47,736,789	Sal&Wg	46.4069%	22,153,184
261		Employee OPEB	3,115,279	(2,607,019)	508,260	Sal&Wg	46.4069%	235,868
262		Empl Ben-OPEB-MO	(385,309)	0	(385,309)	100% MO	0.0000%	0
263		Empl Ben-OPEB-KS	(545,034)	10,850	(534,184)	100% KS	100.0000%	(534,184)
264		Other Miscellaneous Employee Benefits	31,059,075	66,421	31,125,496	Sal&Wg	46.4069%	14,444,391
265	927.000	Franchise Requirements	0	0	0	C1	47.3951%	0
266	928.000	Regulatory Comm Exp						
267		Regulatory Comm Exp-FERC Assment	918,283	(841,180)	77,103	E1	43.5895%	33,609
268		Reg Comm Exp- KCC Assmnt - 100% KS	1,329,309	(80,954)	1,248,355	100% KS	100.0000%	1,248,355
269		Reg Comm Exp- MPSC Assmnt - 100% MO	1,757,640	257,169	2,014,809	100% MO	0.0000%	0
270		Reg Comm Exp- MO Proceeding 100% MO	1,109,496	15,457	1,124,953	100% MO	0.0000%	0
271		Reg Comm Exp- KS Proceeding 100% KS	677,512	133,593	811,105	100% KS	100.0000%	811,105
272		Reg Comm Exp- FERC Proceed - Allocated	0	0	0	E1	43.5895%	0
273		Regulatory Comm Expense- FERC Proceedings 100%	0	0	0	NonJur/Wh	0.0000%	0
274		Load Research Expenses- 100% MO	0	0	0	100% MO	0.0000%	0
275		Miscellaneous Regulatory Expense	1,697,337	(33,777)	1,663,560	D1	47.0659%	782,969
276	929.000	Duplicate Charges-Credit	0	0	0	PTD	46.2712%	0
277	930.100	General Advertising Expense						
278		General Advertising Expense - Allocated	35,660	(35,660)	0	C1	47.3951%	0
279		General Advertising Expense - 100% MO	0	0	0	100% MO	0.0000%	0
280	930.200	Miscellaneous General Expense	6,298,107	(578,032)	5,720,075	E1	43.5895%	2,493,352
281	931.000	Admin & General Expense-Rents-Allocated	3,223,125	(64,162)	3,158,963	E1	43.5895%	1,376,976
282		Admin & General Expense-Rents-100% MO	(200,220)	0	(200,220)	100% MO	0.0000%	0
283		Admin & General Expense-Rents-100% KS	0	0	0	100% KS	100.0000%	0
284	933.000	Transportation Expense	0	(418,743)	(418,743)	Dist Plt	44.3024%	(185,513)
285		**TOTAL OPERATION- ADMIN. & GENERAL EXP**	**160,875,248**	**(27,978,670)**	**132,896,578**			**62,026,213**
286		**MAINT, ADMIN. & GENERAL EXP**						
287	935.000	Maintenance Of General Plant	8,582,591	1,782,570	10,365,161	PTD	46.2712%	4,796,085
288		TOTAL MAINT, ADMIN. & GENERAL EXP	8,582,591	1,782,570	10,365,161			4,796,085
289		**TOTAL ADMIN. & GENERAL EXPENSES**	**169,457,839**	**(26,196,100)**	**143,261,739**			**66,822,298**
290		**TOTAL ELEC OPER & MAINT EXP**	**958,414,392**	**(72,065,194)**	**886,349,198**			**382,660,716**
291		**DEPRECIATION EXPENSE**					Blended	
292	403.000	Depreciation Expense, Dep. Exp.	241,455,312	39,384,594	280,839,906		46.4463%	130,439,716
293	403.001	Other Depreciation		0	0			
294		**TOTAL DEPRECIATION EXPENSE**	**241,455,312**	**39,384,594**	**280,839,906**			**130,439,716**

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295		**AMORTIZATION EXPENSE**						
296	404.000	Amortization of Limited Term Plant-Allocated	1,908,936	(35,229)	1,873,707	PTD	46.2712%	866,987
297	405.001	Amort-Iatan Reg Asset & Oth Non-Plant - MO	1,126,101	0	1,126,101	100% MO	0.0000%	0
298	405.001	Amort-Iatan, LC & WC Reg Asset/Liab - KS	(153,711)	(1,040,440)	(1,194,151)	100% KS	100.0000%	(1,194,151)
299	405.010	Amortization-Other Plant-Allocated	32,677,180	8,863,226	41,540,406	PTD	46.2712%	19,221,246
300	405.010	Amortiz of Unrecovered Reserve-KS	1,661,925	0	1,661,925	100% KS	100.0000%	1,661,925
301	405.010	Amortiz of Unrecov Dist Meters-KS	1,115,338	0	1,115,338	100% KS	100.0000%	1,115,338
302	407.300	Regulatory Debits	940,556	0	940,556	NonJur/Wh	0.0000%	0
303	407.400	Regulatory Credits	(30,300,963)	0	(30,300,963)	NonJur/Wh	0.0000%	0
304	407.400	Regulatory Credits - Migration Amortiz	31,854	95,563	127,417	100% KS	100.0000%	127,417
305	411.100	Accretion Exp-Asset Retirement Obligation	13,374,942	0	13,374,942	NonJur/Wh	0.0000%	0
306	411.000	Write down-Emissions Allowance Liab-Whsl	0	0	0	NonJur/Wh	0.0000%	0
307		**TOTAL AMORTIZATION EXPENSE**	**22,382,158**	**7,883,119**	**30,265,277**			**21,798,762**
308		**OTHER OPERATING EXPENSES**						
309		Taxes Other Than Income Taxes-Allocated						
310	408.100	KS Property Tax RIDER	(2,025,122)	2,025,122	0	100% KS	100.0000%	0
311	408.103	Other Miscellaneous Taxes	2,808	0	2,808	PTD	46.2712%	1,299
312	408.110	KCMO City Earnings Tax-100% MO	592,700	0	592,700	100% MO	0.0000%	0
313	408.120	Property Tax	79,415,857	1,448,301	80,864,158	Elec Plt wo WC	46.1235%	37,297,346
314	408.121	Property Tax - Wolf Creek	20,434,436	(757,066)	19,677,370	WC Plt	47.0659%	9,261,331
315	408.130	Gross Receipts Tax-100% MO	70,188,095	0	70,188,095	100% MO	0.0000%	0
316	408.140	Payroll Tax, incl Unemployment	12,165,441	489,200	12,654,641	Sal&Wg	46.4069%	5,872,632
317	408.140	ORVIS - KS	41,152	(41,152)	(0)	100% KS	100.0000%	(0)
318		**TOTAL OTHER OPERATING EXPENSES**	**180,815,367**	**3,164,405**	**183,979,772**			**52,432,608**
319		**TOTAL OPERATING EXPENSE**	**1,403,067,229**	**(21,633,076)**	**1,381,434,153**			**587,331,802**
320		**NET INCOME BEFORE TAXES**	**472,580,173**	**(23,708,768)**	**448,871,405**			**175,849,606**
321	409.100	**INCOME TAXES**						
322		Current Income Taxes	69,211,672	15,103,075	84,314,747	Sch11		31,705,059
323		**TOTAL CURRENT INCOME TAXES**	**69,211,672**	**15,103,075**	**84,314,747**			**31,705,059**
324	410 & 411	**DEFERRED INCOME TAXES**						
325		Deferred Income Taxes - Def. Inc. Tax.	52,303,590	(55,528,294)	(3,224,704)	Sch 11		(1,961,053)
326		Amortization of Deferred ITC	(962,914)	(124,738)	(1,087,652)	Sch 11		(503,270)
327		Amort of Excess Deferred Income Taxes		(2,478,027)	(2,478,027)	Sch 11		(1,146,613)
328		Amort of Cost of Removal-ER-2007-0291	0	354,438	354,438	Sch 11		0
329		**TOTAL DEFERRED INCOME TAXES**	**51,340,676**	**(57,776,621)**	**(6,435,945)**			**(3,610,936)**
330								
331		**TOTAL INCOME TAXES**	**120,552,348**	**(42,673,546)**	**77,878,802**			**28,094,123**
332								
333		**NET OPERATING INCOME**	**352,027,825**	**18,964,778**	**370,992,603**			**147,755,483**
		Summary of Fuel & Purchased Power Expense						
		Acct 501 - Steam Prod	223,812,171	2,566,341	226,378,512			98,825,130
		Acct 509 - Allowances	(3,982,122)	0	(3,982,122)			(1,680,679)
		Acct 518 - Nuclear Fuel	30,867,974	0	30,867,974			13,455,196
		Acct 547 - CT's and Other Prod	6,959,441	1,178	6,960,619			3,028,088
		Total Fuel	257,657,464	2,567,519	260,224,983			113,627,734
		Acct 555 - Purchased Power	144,601,307	0	144,601,307			63,030,987
		Total Fuel & Purchased Power	402,258,771	2,567,519	404,826,290			176,658,721

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Income Statement

Line No.	Description	Total Company	Adjustment	Adjusted Total Comany	Adjusted Jurisdictional
	A	B	C	D	F
1	Operating Revenue	1,875,647,402	(45,341,844)	1,830,305,558	763,181,408
2	Operating & Maintenance Expenses:				
3	Production	578,443,165	6,282,108	584,725,273	266,503,668
4	Transmission	88,331,518	(64,761,786)	23,569,732	10,321,267
5	Distribution	54,847,952	314,570	55,162,522	24,464,592
6	Customer Accounting	19,657,039	11,783,780	31,440,819	13,435,205
7	Customer Services	47,148,468	513,446	47,661,914	863,818
8	Sales	528,411	(1,211)	527,200	249,867
9	A & G Expenses	169,457,839	(26,196,100)	143,261,739	66,822,298
10	Total O & M Expenses	958,414,392	(72,065,194)	886,349,198	382,660,716
11	Depreciation Expense	241,455,312	39,384,594	280,839,906	130,439,716
12	Amortization Expense	22,382,158	7,883,119	30,265,277	21,798,762
13	Taxes other than Income Tax	180,815,367	3,164,405	183,979,772	52,432,608
14	Net Operating Income before Tax	472,580,173	(23,708,768)	448,871,405	175,849,606
15	Income Taxes Current	69,211,672	15,103,075	84,314,747	31,705,059
16	Income Taxes Deferred	52,303,590	(57,651,883)	(5,348,293)	(3,107,666)
17	Investment Tax Credit	(962,914)	(124,738)	(1,087,652)	(503,270)
18	Total Taxes	120,552,348	(42,673,546)	77,878,802	28,094,123
19	Total Net Operating Income	352,027,825	18,964,778	370,992,603	147,755,483

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Summary of Adjustments

Line No.	Adj No.	Description	Witness	Increase (Decrease)			
	A	B		D	E	F	G
					Adjust to 6-30-18 - Update Date		
				Total Adjustments Incr (Decr)	Allocated Adjs Incr (Decr)	100% MO & Whsl Adjs (2) Incr (Decr)	100% KS Adjs Incr (Decr)
1	**JURISDICTIONAL COST OF SERVICE**						
2	**OPERATING REVENUE**						
3	R-20	Normalize KS Retail revenues (KS only)	Bass / Miller / Nunn	(29,481,934)			(29,481,934)
4	R-21a	Adjust KS forfeited discounts LPC for R-20 (KS Only)	Nunn	25,213			25,213
5	R-21b	Adjust KS forfeited discounts LPC - ASK (KS only)	Nunn	71,304			71,304
6	R-49	CNN Revenue	Nunn	128,376	128,376		
7	R-82	Transmission Delivery Charge Adjustment	Klote	(16,084,803)	(16,084,803)		
8				(45,341,844)	(15,956,427)	0	(29,385,417)
9	**OPERATING EXPENSES**						
10	CS-4	Reflect KCREC test year bad debt expense in KCP&L's COS	Nunn	7,463,092		5,462,528	2,000,564
11	CS-9	Reflect KCREC test year bank commitment fees in KCP&L's COS	Nunn	1,981,200	1,981,200		
12	CS-10	Reflect test year interest on customer deposits in COS	Nunn	192,124		179,346	12,778
13	CS-11	Reverse prior period and non-recurring test year amounts.	Nunn	(4,107,664)	(4,107,664)		
14	CS-20a	Normalize bad debt expense related to test year revenue	Nunn	184,170			184,170
15	CS-20b	Normalize bad debt expense related to jurisdictional "Ask" (KS only)	Nunn	97,550			97,550
16	CS-23	Remove ECA Under Collection	Nunn	2,856,971			2,856,971
17	CS-26	ECA costs	n/a	0	0		
18	CS-27	Wolf Creek Water Contract	Klote	771,494	771,494		
19	CS-35	Eliminate Wolf Creek Mid-Cycle Outage	Klote	0	0		
20	CS-36	Annualize Wolf Creek refueling outage amortization	Klote	(428,995)	378,270	(807,265)	
21	CS-37	Adjust Nuclear decommissioning expense	Klote	0			
22	CS-39	IT Software Maintenance	Klote	610,529	610,529		
23	CS-40	Transmission Maintenance	Nunn	0	0		
24	CS-41	Distribution Maintenance	Nunn	0	0		
25	CS-42	Generation Maintenance	Nunn	0	0		
26	CS-43	Wolf Creek Maintenance	Nunn	0	0		
27	CS-49	Miscellaneous O&M	Nunn	359,992	359,992		
28	CS-50	Annualize salary and wage expense for changes in staffing levels and base pay rates	Klote	3,496,847	3,467,493	15,457	13,897
29	CS-51	Normalize incentive compensation costs	Klote	(1,693,078)	(1,693,078)		
30	CS-52	Normalize 401(k) costs	Klote	(151,259)	(151,259)		
31	CS-55	Severance / ORVS	Nunn	(843,995)			(843,995)
32	CS-60	Annualize other benefit costs	Klote	154,768	154,768		
33	CS-61	Annualize OPEB expense	Klote	(2,596,696)	(2,596,696)		
34	CS-65	Annualize Pension expense (includes SERP)	Klote	(2,203,060)	(2,203,060)		
35	CS-70	Annualize Insurance premiums	Klote	387,223	387,223		
36	CS-71	Normalize injuries and damages expense	Nunn	(11,211,892)	(11,211,892)		
37	CS-76	Annualize interest on customer deposits	Nunn	33,915		17,387	16,528
38	CS-77	Annualize Customer Accounts expense for credit card payment costs	Nunn	138,472	138,472		
39	CS-78	Annualize KCREC bank fees related to sale of receivables	Nunn	938,234	938,234		
40	CS-80	Amortize KS Rate Case expenses	Nunn	119,696			119,696
41	CS-82	Transmission Delivery Charge Adjustment	Klote	(70,050,803)	(70,034,555)	0	(16,248)
42	CS-85	Annualize regulatory assessments	Nunn	253,315	77,100	257,169	(80,954)
43	CS-88	CIPS/Cyber Security O&M	Nunn	3,671,539	3,671,539		
44	CS-89	Meter Replacement O&M	Nunn	598,073	598,073		
45	CS-90	Advertising	Nunn	(36,260)	(36,260)		
46	CS-92	Adjust dues, donations and contributions	Nunn	38,390	38,390		
47	CS-95	Merger Effects	Klote	1,372,150			1,372,150
48	CS-96	Amortize Merger transition costs (KS only)	Nunn	(111,111)			(111,111)
49	CS-99	Flood Reimbursement Amortization	Nunn	155,380	155,380		
50	CS-101	Amortize Talent Assessment severance and outplacement regulatory asset	Nunn	(411,640)			(411,640)
51	CS-102	Employee Augmentation	Nunn	(26,418)			(26,418)

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Summary of Adjustments

Line No.	Adj No.	Description	Witness	Increase (Decrease)			
	A	B		D	E	F	G
					Adjust to 6-30-18 - Update Date		
				Total Adjustments	Allocated Adjs	100% MO & Whsl Adjs (2)	100% KS Adjs
				Incr (Decr)	Incr (Decr)	Incr (Decr)	Incr (Decr)
52	CS-103	EE Amortization	Nunn	173,685			173,685
53	CS-107	Transource Account Review Amortization	Nunn	21,453			21,453
54	CS-110	Flood AAO Amortization	Nunn	0			0
55	CS-115	Amortize Legal fee reimbursement	Nunn	14,458			14,458
56	CS-117	Common-use Billings	Klote	(7,414,333)	(7,414,333)		
57	CS-120	Annualize depr exp based on jurisdictional depr rates applied to jurisdictional plant-in-service at indicated period - unit trains & transportation equipment	Klote	1,957,813	1,957,813		
58				(73,244,671)	(83,762,827)	5,124,622	5,393,534
59	**Depreciation Expense**						
60	CS-120	Annualize depreciation expense based on jurisdictional depreciation rates applied to jurisdictional plant-in-service at indicated period	Klote	39,384,594	39,384,594		
61				39,384,594	39,384,594	0	0
62	**Amortization Expense**						
63	CS-111	Amortization Iatan 1 & Cmn Reg Asset	Nunn	0			0
64	CS-113	Amortization of La Cygne Reg Asset - Depr Deferral	Nunn	0			0
65	CS-118	Amortize Meter Replacement Unrecovered Reserve	Nunn	0			0
66	CS-121	Annualize plant amortization expense based on jurisdictional amortization rates applied to unamortized jurisdictional plant-in-service at indicated period	Klote	9,709,293	9,709,293		
67	CS-122	Amortize General Plant Unrecovered Reserve	Klote	0			0
68	CS-130	Amortize Customer Migration	Nunn	95,563			95,563
69	CS-131	Amortize La Cygne BUD Plant Reg Liability	Nunn	(992,933)			(992,933)
70	CS-132	Amortize La Cygne BUD Deferred Depreciation	Nunn	(5,833)			(5,833)
71	CS-133	Amortize Wolf Creek BUD Plant Reg Liability	Nunn	(41,675)			(41,675)
72				8,764,415	9,709,293	0	(944,878)
73	**Taxes Other than Income**						
74	CS-53	Annualize FICA payroll tax expense	Klote	746,229	746,229		
75	CS-126	Adjust property tax expense	Klote	2,716,357	2,716,357		
76				3,462,586	3,462,586	0	0
77	**Income Tax Expense**						
78	CS-125	Reflect adjustments to Schedule 9, Allocation of Current and Deferred Income Taxes	Klote	(42,673,546)	(43,027,984)	354,438	
79				(42,673,546)	(43,027,984)	354,438	0
80		**Total Electric Oper. Expenses**		(64,306,622)	(74,234,338)	5,479,060	4,448,656
81		**Net Electric Operating Income**		18,964,778	58,277,911	(5,479,060)	(33,834,073)

(1) All amounts are total company; if an adjustment is applicable to only KS or MO it is so indicated
(2) These adjustments affect Missouri and Wholesale jurisdictions and are not discussed in testimony supporting the Missouri rate case.

SECTION 10
DEPRECIATION AND AMORTIZATION

Kansas City Power & Light Company
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Depreciation Expense - Schedule 5

			TOTAL COMPANY - JURIS BASIS			JURISDICTIONAL DEPRECIATION		
			From Schedule 3	Depr%		From Schedule 3	Depr%	
Line No.	Account No.	Plant Account Description	Adjusted Jurisdictional Plt in Svc	Depr Rate	Depreciation Expense	Adjusted Jurisdictional Plt in Svc	Depr Rate	Depreciation Expense
	A	B	C	D	E	C	D	E
1	**INTANGIBLE PLANT**							
2	30100	Organization	$ 70,749	0.00%	-	$ 32,737	0.00%	-
3	30200	Franchises and Consents	22,480	0.00%	-	-	0.00%	-
4	30301	Miscellaneous Intangibles (Like 353)	1,993,381	0.00%	-	938,203	0.00%	-
5		Misc Intang ble Plant-5-Year Software, excl Wolf Creek						
6	30302	Customer Related	70,782,620	0.00%	-	33,547,494	0.00%	-
7	30302	Energy Related	9,244,649	0.00%	-	4,029,696	0.00%	-
8	30302	Demand Related	44,786,683	0.00%	-	21,079,255	0.00%	-
9	30302	Corporate Software	35,172,550	0.00%	-	16,322,505	0.00%	-
10	30302	Transmission Related	3,752,380	0.00%	-	1,766,092	0.00%	-
11		Miscl Intangible Plt - 10 yr Software						
12	30303	Customer Related	89,644,247	0.00%	-	42,486,981	0.00%	-
13	30303	Energy Related	37,686,962	0.00%	-	16,427,558	0.00%	-
14	30303	Demand Related	27,642,958	0.00%	-	13,010,407	0.00%	-
15	30303	Corporate Software	31,582,436	0.00%	-	14,656,443	0.00%	-
16	30305	Miscl Intang Plt - WC 5yr Software	28,013,252	0.00%	-	13,184,689	0.00%	-
17	303XX	Miscl Intang Plt - 15yr Software	121,844,170	0.00%	-	57,347,055	0.00%	-
18	30307	Miscl Intg Plt-Srct (Like 312)	34,284	0.00%	-	16,136	0.00%	-
19	30308	Miscl Intang Trans Line (Like 355)	6,737,384	0.00%	-	3,171,010	0.00%	-
20	30309	Miscl Intang Trans Ln MINT Line	54,110	0.00%	-	25,468	0.00%	-
21	30310	Miscl Intang-Iatan Hwy & Bridge	3,179,170	0.00%	-	1,496,305	0.00%	-
22	30311	Misc Intan-LaCygne Road Overpass	853,516	0.00%	-	401,715	0.00%	-
23	30312	Misc Intan-Montrose Highway	481,496	0.00%	-	226,620	0.00%	-
24	30313	Misc Intan-Radio Frequencies	1,435,164	0.00%	-	675,473	0.00%	-
25		**TOTAL PLANT INTANGIBLE**	515,014,644		-	240,841,842		-
26	**PRODUCTION PLANT**							
27	**STEAM PRODUCTION**							
28	31000	Sm Pr-Land	9,644,655	0.00%	-	4,539,343	0.00%	-
29	31100	Stm Pr-Structures-Elec	309,871,091	4.22%	13,076,560	145,843,618	4.22%	6,154,601
30	31101	Stm Pr-Struc-Lshd Impr-P&M	1,255,599	0.00%	-	590,959	0.00%	-
31	31102	Stm Pr-Struc-H5 Rebuild	8,653,542	0.42%	36,345	4,072,867	0.42%	17,106
32	31104	Stm Pr-Structure Iatan 2-Elec	93,553,728	1.88%	1,758,810	44,031,904	1.88%	827,800

Filed in Accordance with K.A.R. 21-1-231(c)(4)(J)

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Depreciation Expense - Schedule 5

			TOTAL COMPANY - JURIS BASIS			JURISDICTIONAL DEPRECIATION		
			From Schedule 3	Depr%		From Schedule 3	Depr%	
Line No.	Account No.	Plant Account Description	Adjusted Jurisdictional Plt in Svc	Depr Rate	Depreciation Expense	Adjusted Jurisdictional Plt in Svc	Depr Rate	Depreciation Expense
33	31115	Stm Pr-Struc-Addl Amort-100% KS	-	[redacted]	-	-	[redacted]	-
34	31200	Stm Pr-Boiler Plt Equip-Elec	1,792,891,249	4.32%	77,452,902	843,840,403	4.32%	36,453,905
35	31201	Stm Pr-Boiler-Unit Train-Elec	20,764,028	14.34%	2,977,562	9,772,776	14.34%	1,401,416
36	31202	Stm Pr-Boiler AQC Equip-Elec	2,824,017	0.00%	-	1,329,149	0.00%	-
37	31203	Stm Pr-Boiler-H5 Rebuild	218,146,524	0.67%	1,461,582	102,672,625	0.67%	687,907
38	31204	Stm Pr-Boiler Iatan 2-Elec	664,161,774	2.24%	14,877,224	312,593,716	2.24%	7,002,099
39	31213	Stm Pr-Boiler Plt Eq-Iat 1 & Com-Juris Disallow-100% KS	(1,249,901)	4.32%	(53,996)	(1,249,901)	4.32%	(53,996)
40	31214	Stm Pr-Boiler Plt Eq-Iat 2-Juris Disallow-100% KS	(4,477,350)	2.24%	(100,293)	(4,477,350)	2.24%	(100,293)
41	31215	Stm Pr-Boiler-Addl Amort-100% KS	-	[redacted]	-	-	[redacted]	-
42	31400	Stm Pr-Turbogenerator-Elec	295,756,065	3.40%	10,055,706	139,200,254	3.40%	4,732,809
43	31404	Stm Pr-Turbogen Iatan 2-Elec	226,464,331	2.05%	4,642,519	106,587,475	2.05%	2,185,043
44	31415	Stm Pr-Turbogen-Addl Amort-100% KS	-	[redacted]	-	-	[redacted]	-
45	31500	Stm Pr-Accessory Equip-Elec	197,983,713	3.71%	7,345,196	93,182,816	3.71%	3,457,082
46	31501	Stm Pr-Acc-H5 Rebuild	30,541,651	0.67%	204,629	14,374,703	0.67%	96,311
47	31502	Stm Pr-Accessory Equip-Comp	-	0.00%	-	-	0.00%	-
48	31504	Stm Pr-Accessory Iatan 2-Elec	57,715,332	2.25%	1,298,595	27,164,240	2.25%	611,195
49	31515	Stm Pr-Access-Addl Amort-100% KS	-	[redacted]	-	-	[redacted]	-
50	31600	St Pr-Misc Pwr Plt Equip-Elec	43,281,155	3.96%	1,713,934	20,370,665	3.96%	806,678
51	31601	St Pr-Misc Eq-H5 Rebuild	2,305,161	0.76%	17,519	1,084,945	0.76%	8,246
52	31604	St Pr-MiscPwr Eq Iatan 2-Elec	4,479,972	1.59%	71,232	2,108,539	1.59%	33,526
53	31615	St Pr-MiscPwr Eq-Addl Amort-100% KS	-	[redacted]	-	-	[redacted]	-
54		**TOTAL STEAM PRODUCTION PLANT**	3,974,566,334		136,836,025	1,867,633,747		64,321,435
55	**NUCLEAR PRODUCTION**							
56	32000	Nucl Pr-Land & Land Rights	3,619,298	0.00%	-	1,703,455	0.00%	-
57	32100	Nucl Pr-Struct & Improv-Elec	429,142,208	1.73%	7,424,160	201,979,642	1.73%	3,494,248
58	32200	Nucl Pr-Reactor Plt Eq-Elec	986,812,153	2.44%	24,078,217	464,452,021	2.44%	11,332,629
59	32300	Nucl Pr-Turbine/Generato-Elec	251,520,320	1.72%	4,326,150	118,380,302	1.72%	2,036,141
60	32400	Nucl Pr-Accessory Equip-Elec	154,233,412	2.39%	3,686,179	72,591,344	2.39%	1,734,933
61	32500	Nucl Pr-Misc Pwr Plt Eq-Elec	112,613,345	3.06%	3,445,968	53,002,485	3.06%	1,621,876
62	32803	Nucl Pr-MPSC Disall-100% KS basis	(115,576,675)	2.44%	(2,820,071)	(54,397,202)	2.44%	(1,327,292)
63	32805	Nucl Pr-Disal-Pre 1988 Res	-		-	-		-
64		**TOTAL NUCLEAR PRODUCTION PLANT**	1,822,364,062		40,140,602	857,712,047		18,892,536

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Depreciation Expense - Schedule 5

			TOTAL COMPANY - JURIS BASIS			JURISDICTIONAL DEPRECIATION		
			From Schedule 3	Depr%		From Schedule 3	Depr%	
Line No.	Account No.	Plant Account Description	Adjusted Jurisdictional Plt in Svc	Depr Rate	Depreciation Expense	Adjusted Jurisdictional Plt in Svc	Depr Rate	Depreciation Expense
65	**OTHER PRODUCTION**							
66	34000	Oth Prod-Land-Elec-CT's	1,008,931	0.00%	-	474,863	0.00%	-
67	34001	Oth Prod-LandRights-Easements-CT's	93,269	0.00%	-	43,898	0.00%	-
68	34100	Oth Prod-Structures-Elec-CT's	8,627,909	2.66%	229,502	4,060,803	2.66%	108,017
69	34102	Oth Prod-Struct-Elec-Wind	5,073,169	5.31%	269,385	2,387,733	5.31%	126,789
70	34200	Oth Prod-Fuel Holders-Elec-CT's	12,097,531	2.46%	297,599	5,693,812	2.46%	140,068
71	34400	Oth Prod-Generators-Elec-CT's	293,734,996	2.29%	6,726,531	138,249,020	2.29%	3,165,903
72	34401	Other Prod-Generators-Elect-SOLAR	1,009,191	5.29%	53,386	474,985	5.29%	25,127
73	34402	Oth Prod-Generators-Elec-Wind	261,157,639	5.34%	13,945,818	122,916,193	5.34%	6,563,725
74	34415	Oth Prod-Generators-Wind-Addl Amort-100% KS		[redacted]	-	-	[redacted]	-
75	34500	Oth Prod-Accessory Equip-Elec-CT's	22,796,098	1.92%	437,685	10,729,189	1.92%	206,000
76	34502	Oth Prod-Accesry Eq-Elec-Wind	707,218	6.51%	46,040	332,858	6.51%	21,669
77	34600	Oth Prod-Misc Pwr Plt Equip-Elec-CT's	2,723,894	3.59%	97,788	1,282,025	3.59%	46,025
78	34602	Oth Prod-Misc Pwr Plt Eq-Wind	165,112	7.26%	11,987	77,712	7.26%	5,642
79		**TOTAL OTHER PRODUCTION PLANT**	609,194,958		22,115,722	286,723,090		10,408,964
80		**RETIREMENTS WORK IN PROGRESS-PROD**						
81		Production - Salvage & Removal Retirements not classified-Nuclear and Steam						
82		TOTAL RETIREMENTS WORK IN PROGRESS-PROD		[redacted]			[redacted]	
83		**TOTAL PRODUCTION PLANT**	6,406,125,353		199,092,350	3,012,068,884		93,622,935
84	**TRANSMISSION PLANT**							
85	35000	Land - Transmission Plant	277,173	0.00%	-	130,454	0.00%	-
86	35001	Land Rights - Transmission Plant	4,368,183	0.00%	-	2,055,925	0.00%	-
87	35002	Land Rights- TP- Wolf Creek	-	0.00%	-	-	0.00%	-
88	35200	Structures & Improvements - TP	1,038,377	1.13%	11,734	488,721	1.13%	5,523
89	35201	Structures & Improvements - TP - Wolf Creek	43,811	1.13%	495	20,620	1.13%	233
90	35300	Station Equipment - Transmission Plant	31,278,775	1.62%	506,716	14,721,637	1.62%	238,491
91	35301	Station Equipment - Wolf Creek -TP	2,709,527	1.62%	43,894	1,275,263	1.62%	20,659
92	35303	Station Equipment - Communications	1,371,530	1.44%	19,750	645,523	1.44%	9,296
93	35315	Station Equip - Transm Plt-Addl Amort - 100% KS	-	[redacted]		-	[redacted]	
94	35400	Towers and Fixtures - Transmission Plant	749,998	0.56%	4,200	352,993	0.56%	1,977

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Depreciation Expense - Schedule 5

			TOTAL COMPANY - JURIS BASIS			JURISDICTIONAL DEPRECIATION		
			From Schedule 3	Depr%		From Schedule 3	Depr%	
Line No.	**Account No.**	**Plant Account Description**	**Adjusted Jurisdictional Plt in Svc**	**Depr Rate**	**Depreciation Expense**	**Adjusted Jurisdictional Plt in Svc**	**Depr Rate**	**Depreciation Expense**
95	35500	Poles and Fixtures - Transmission Plant	23,726,277	2.33%	552,822	11,166,986	2.33%	260,191
96	35501	Poles & Fixtures - Wolf Creek	10,190	2.33%	237	4,796	2.33%	112
97	35600	Overhead Conductors & Devices - TP	19,682,235	1.33%	261,774	9,263,621	1.33%	123,206
98	35601	Overhead Conductors & Devices- Wlf Crk	6,894	1.33%	92	3,245	1.33%	43
99	35700	Underground Conduit	717,246	0.85%	6,097	337,578	0.85%	2,869
100	35800	Underground Conductors & Devices	567,078	0.69%	3,913	266,901	0.69%	1,842
101		Transmission-Salvage & Removal : Retirements not classified	-					
102		**TOTAL TRANSMISSION PLANT**	86,547,296		1,411,724	40,734,264		664,441
103	**DISTRIBUTION PLANT**							
104	36000	Distr bution Land Electric	9,267,377	0.00%	-	4,597,462	0.00%	-
105	36001	Distr bution Depreciable Land Rights	16,589,694	0.00%	-	6,912,527	0.00%	-
106	36100	Distr bution Structures & Improvements	14,940,701	1.47%	219,628	6,464,154	1.47%	95,023
107	36200	Distr bution Station Equipment	248,791,616	1.93%	4,801,678	94,237,288	1.93%	1,818,780
108	36203	Distr bution Station Equipment-Communicatons	4,661,709	4.76%	221,897	2,058,979	4.76%	98,007
109	36300	Distr bution Energy Storage Equipment	2,413,035	0.00%	-	-	0.00%	-
110	36400	Distr bution Poles, Tower, & Fixtures	390,480,917	2.61%	10,191,552	176,593,042	2.61%	4,609,078
111	36500	Distr bution Overhead Conductor	274,146,994	2.45%	6,716,601	118,932,368	2.45%	2,913,843
112	36600	Distr bution Underground Circuit	294,592,193	2.03%	5,980,222	123,819,161	2.03%	2,513,529
113	36700	Distr bution Underground Conductors	545,503,796	1.94%	10,582,774	257,573,255	1.94%	4,996,921
114	36800	Distr bution Line Transformers	311,397,862	2.03%	6,321,377	134,715,386	2.03%	2,734,722
115	36900	Distr bution Services	149,474,119	2.69%	4,020,854	72,259,377	2.69%	1,943,777
116	37000	Distr bution Meters Electric	57,911,142	2.99%	1,731,543	27,697,336	2.99%	828,150
117	37002	Distr bution AMI Meters Electric	62,503,526	4.88%	3,050,172	28,452,605	4.88%	1,388,487
118	37100	Distr bution Cust Prem Install	14,688,870	4.50%	660,999	4,612,540	4.50%	207,564
119	37101	Distr bution Electric Vehicle Charging Stations	11,847,840	9.84%	1,165,827	5,621,136	9.84%	553,120
120	37300	Distr bution Street Light and Traffic Signal	25,972,782	3.59%	932,423	13,677,163	3.59%	491,010
121		Distr bution-Salvage and removal: Retirements not classified						
122		**TOTAL DISTRIBUTION PLANT**	2,435,184,174		56,597,547	1,078,223,781		25,192,013

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Depreciation Expense - Schedule 5

			TOTAL COMPANY - JURIS BASIS			JURISDICTIONAL DEPRECIATION		
			From Schedule 3	Depr%		From Schedule 3	Depr%	
Line No.	**Account No.**	**Plant Account Description**	**Adjusted Jurisdictional Plt in Svc**	**Depr Rate**	**Depreciation Expense**	**Adjusted Jurisdictional Plt in Svc**	**Depr Rate**	**Depreciation Expense**
123	**GENERAL PLANT**							
124	38900	Land and Land Rights - General Plant	3,475,650	0.00%	-	1,608,225	0.00%	-
125	39000	Structures & Improvements - General Plant	113,538,553	2.39%	2,713,571	52,535,656	2.39%	1,255,602
126	39003	Struct & Imprv - Leasehold (801 Char)	6,454,612	0.00%	-	2,986,627	0.00%	-
127	39005	Struct & Imprv - Leasehold (One KC Place)	29,613,959	0.00%	-	13,702,736	0.00%	-
128	39100	Office Furniture & Equipment - Gen. Plt	10,949,982	5.00%	547,499	5,066,689	5.00%	253,334
129	39101	Office Furniture & Equip - Wolf Creek	12,455,693	5.00%	622,785	5,763,399	5.00%	288,170
130	39102	Office Furniture & Equip - Computer	59,095,955	20.00%	11,819,191	27,344,411	20.00%	5,468,882
131	39110	Office Furn & Equip-Gen-Unrecovered Res-100% KS	-	[redacted]		-	[redacted]	
132	39111	Office Furn & Equip-Wlf Crk-Unrecov Res-100% KS	-	[redacted]		-	[redacted]	
133	39112	Office Furn & Equip-Computer-Unrec Res-100% KS	-	[redacted]		-	[redacted]	
134	39200	Transportation Equipment- Autos	2,489,494	10.57%	263,139	1,151,919	10.57%	121,758
135	39201	Transportation Equipment- Light Trucks	10,422,060	10.26%	1,069,303	4,822,413	10.26%	494,780
136	39202	Transportation Equipment - Heavy Trucks	36,776,601	7.85%	2,886,963	17,016,976	7.85%	1,335,833
137	39203	Transportation Equipment - Tractors	595,866	5.09%	30,330	275,714	5.09%	14,034
138	39204	Transportatiob Equipment - Trailers	2,052,204	2.79%	57,256	949,580	2.79%	26,493
139	39300	Stores Equipment - General Plant	791,559	4.00%	31,662	366,264	4.00%	14,651
140	39310	Stores Equip - Gen - Unrecovered Reserve-100% KS		[redacted]			[redacted]	
141	39400	Tools, Shop, & Garage Equipment-Gen. Plt	8,097,810	5.00%	404,890	3,746,954	5.00%	187,348
142	39410	Tools, Shop, & Gar Equip-Gen-Unrecov Res-100% KS		[redacted]			[redacted]	
143	39500	Laboratory Equipment	7,424,682	5.00%	371,234	3,435,490	5.00%	171,774
144	39510	Laboratory Equipment-Unrecovered Reserve-100% KS		[redacted]			[redacted]	
145	39600	Power Operated Equipment - Gen. Plt	30,192,755	5.46%	1,648,524	13,970,552	5.46%	762,792
146	39700	Communication Equipment - Gen. Plt	125,703,462	6.67%	8,384,421	58,164,507	6.67%	3,879,573
147	39710	Communica Equip-Unrecov Res-100% KS		[redacted]			[redacted]	
148	39701	Communications Equip - Wolf Creek	140,535	6.67%	9,374	65,027	6.67%	4,337
149	39800	Miscellaneous Equipment - Gen. Plt	3,253,883	5.00%	162,694	1,505,611	5.00%	75,281
150	39810	Miscellaneous Equip-Gen-Unrecov Res-100% KS		[redacted]			[redacted]	
151		Gen Plant-Slvg & removal/retirements not classified		[redacted]			[redacted]	
152		**TOTAL GENERAL PLANT**	463,525,313		31,022,838	214,478,748		14,354,641
153		**TOTAL PLANT IN SERVICE**	9,906,396,780		288,124,459	4,586,347,518		133,834,030

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Depreciation Expense - Schedule 5

			TOTAL COMPANY - JURIS BASIS			JURISDICTIONAL DEPRECIATION		
			From Schedule 3	Depr%		From Schedule 3	Depr%	
Line No.	**Account No.**	**Plant Account Description**	**Adjusted Jurisdictional Plt in Svc**	**Depr Rate**	**Depreciation Expense**	**Adjusted Jurisdictional Plt in Svc**	**Depr Rate**	**Depreciation Expense**
154		**LESS: DEPR CHARGED TO CLEARING OR OTHER ACCOUNT**						
155		Unit Trains (312) Charged to Inventory			2,977,562			1,401,416
156		Vehicles(392) Charged to Clearing			4,306,992			1,992,897
157		**TOTAL CHARGED TO CLEARINGS**			7,284,554			3,394,313
158		**TOTAL DEPR EXPENSE NET OF CLEARING**			280,839,906			130,439,716

Line		Projected		Test Year	Adjustment (Total Company)	Account
159	**Depreciation of Unit Trains and Vehicles**					
160	Unit Trains	2,977,562		592,500	2,385,062	501
161	Vehicles	4,306,992	PwrPlt	5,329,239		
162	Percent cleared to O&M	41.80%		41.80%		
		1,800,107		2,227,356	(427,248)	933
					1,957,813	

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Depreciation Rates by Jurisdiction — **Per Depr Study**

ACCT. NO.	DESCRIPTION	KANSAS JURISDICTION
	PRODUCTION PLANT	
	STEAM	
31000	LAND & LAND RIGHTS	0.00%
31100	STRUCTURES & IMPROVEMENTS	4.22%
31102	STRUCTURES & IMPROVEMENTS - H5	0.42%
31104	STRUCTURES & IMPROVEMENTS - IATAN 2	1.88%
31200	BOILER PLANT EQUIPMENT	4.32%
31201	UNIT TRAINS	14.34%
31202	AQC EQUIPMENT	0.00%
31203	BOILER PLANT EQUIPMENT - H5	0.67%
31204	BOILER PLANT EQUIPMENT - IATAN 2	2.24%
31213	Boiler Plt Eq - Iatan 1-KS Juris Disallow	4.32%
31214	Boiler Plt Eq - Iatan 2-KS Juris Disallow	2.24%
31400	TURBOGENERATOR UNITS	3.40%
31404	TURBOGENERATOR UNITS-IATAN 2	2.05%
31500	ACCESSORY ELECTRIC EQUIPMENT	3.71%
31501	ACCESSORY ELECTRIC EQUIPMENT - H5	0.67%
31502	ACC ELEC EQUIP - COMPUTERS	0.00%
31504	ACCESSORY ELECTRIC EQUIPMENT-IATAN 2	2.25%
31600	MISC. POWER PLANT EQUIPMENT	3.96%
31601	MISC. POWER PLANT EQUIPMENT - H5	0.76%
31604	MISC. POWER PLANT EQUIPMENT-IATAN 2	1.59%
	NUCLEAR	
32100	STRUCTURES & IMPROVEMENTS	1.73%
32101	MISSOURI GROSS AFDC	0.00%
32200	REACTOR PLANT EQUIPMENT	2.44%
32201	MISSOURI GROSS AFDC	0.00%
32300	TURBOGENERATOR UNITS	1.72%
32301	MISSOURI GROSS AFDC	0.00%
32400	ACCESSORY ELECT. EQUIPMENT	2.39%
32401	MISSOURI GROSS AFDC	0.00%
32500	MISC POWER PLANT EQUIPMENT	3.06%
32501	MISSOURI GROSS AFDC	0.00%
	REGULATORY DISALLOWANCES	
32801	MPSC DISALLOWANCE	0.00%
32802	MPSC DISALLOW - NOT MO JUIRIS	0.00%
32803	KCC DISALLOWANCE	2.44%
32804	KCC DISALLOW - NOT KS JUIRIS	2.44%
32800	MISSOURI GROSS AFDC	0.00%
	OTHER PRODUCTION PLANT - CT	
34000	LAND - CT	0.00%
34001	LAND RIGHTS - CT	0.00%
34100	STRUCTURES & IMPROVEMENTS - CT	2.66%
34200	FUEL HOLDERS,PRODUCERS AND ACC - CT	2.46%
34400	GENERATORS - CT	2.29%
34401	GENERATORS - SOLAR	5.29%
34500	ACCESSORY ELECTRIC EQUIPMENT - CT	1.92%
34600	OTHER PROD-MISC PWR PLT EQUIP - CT	3.59%

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Depreciation Rates by Jurisdiction **Per Depr Study**

ACCT. NO.	DESCRIPTION	KANSAS JURISDICTION
	OTHER PRODUCTION PLANT - WIND	
34000	LAND - WIND	0.00%
34102	STRUCTURES & IMPROVEMENTS - WIND	5.31%
34402	GENERATORS - WIND	5.34%
34502	ACCESSORY ELECTRIC EQUIPMENT - WIND	6.51%
34602	OTHER PROD-MISC PWR PLT EQUIP - WIND	7.26%
	TRANSMISSION PLANT	
	LAND AND LAND RIGHTS	
35000	LAND	0.00%
35002	LAND RIGHTS-WOLF CREEK	0.00%
35200	STRUCTURES AND IMPROVEMENTS	1.13%
35201	STRUCTURES AND IMPROVEMENTS-WOLF CREEK	1.13%
35202	MO GROSS AFDC	0.00%
35300	STATION EQUIPMENT	1.62%
35301	STATION EQUIPMENT - WOLF CREEK	1.62%
35302	MO GROSS AFDC	0.00%
35303	STATION EQUIP - COMMUN EQUIP	1.44%
35400	TOWERS AND FIXTURES	0.56%
35500	POLES AND FIXTURES	2.33%
35501	POLES AND FIXTURES-WOLF CREEK	2.33%
35502	MO GROSS AFDC	0.00%
35600	OVERHEAD CONDUCTORS AND DEVICES	1.33%
35601	OVERHEAD CONDUCTOR & DEVICES-WOLF CREEK	1.33%
35602	MO GROSS AFDC	0.00%
35700	UNDERGROUND CONDUIT	0.85%
35800	UNDERGROUND CONDUCTORS & DEVICES	0.69%
	DISTRIBUTION PLANT	
	LAND & LAND RIGHTS	
36000	LAND (NON-DEPRECIABLE)	0.00%
36100	STRUCTURES & IMPROVEMENTS	1.47%
36200	STATION EQUIPMENT	1.93%
36203	STATION EQUIP - COMMUN EQUIP	4.76%
36300	ENERGY STORAGE EQUIPMENT	0.00%
36400	POLES,TOWERS, & FIXTURES	2.61%
36500	OVERHEAD CONDUCTORS & DEVICES	2.45%
36600	UNDERGROUND CONDUIT	2.03%
36700	UNDERGROUND CONDUCTORS & DEV.	1.94%
36800	LINE TRANSFORMERS	2.03%
36900	SERVICES	2.69%
37000	METERS	2.99%
37002	AMI METERS	4.88%

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ACCT. NO.	DESCRIPTION	KANSAS JURISDICTION	
37100	INSTALLATION ON CUST.PREMISES	4.50%	
37101	ELECTRIC VEHICLE CHARGING STATIONS	9.84%	
37300	STREET LIGHTS & SIGNAL SYSTEMS	3.59%	
	GENERAL PLANT		
39000	STRUCTURES AND IMPROVEMENTS	2.39%	
39100	OFFICE FURNITURE & EQUIPMENT	5.00%	Gen Plt Amortiz
39101	OFFICE FURNITURE & EQUIPMENT-WOLF CREEK	5.00%	Gen Plt Amortiz
39102	OFFICE FURNITURE & EQUIPMENT - COMPUTERS	20.00%	Gen Plt Amortiz
39200	TRANSPORTATION EQUIP - AUTO'S	10.57%	
39201	TRANSPORTATION EQUIP - LIGHT TRUCKS	10.26%	
39202	TRANSPORTATION EQUIP - HEAVY TRUCKS	7.85%	
39203	TRANSPORTATION EQUIP - TRACTORS	5.09%	
39204	TRANSPORTATION EQUIP - TRAILERS	2.79%	
39300	STORES EQUIPMENT	4.00%	Gen Plt Amortiz
39400	TOOLS, SHOP & GARAGE EQUIPMENT	5.00%	Gen Plt Amortiz
39500	LABORATORY EQUIPMENT	5.00%	Gen Plt Amortiz
39600	POWER OPERATED EQUIPMENT	5.46%	
39700	COMMUNICATIONS EQUIPMENT	6.67%	Gen Plt Amortiz
39701	COMMUNICATIONS EQUIPMENT-WOLF CREEK	6.67%	Gen Plt Amortiz
39702	MO GROSS AFDC	0.00%	
39800	MISCELLANEOUS EQUIPMENT	5.00%	Gen Plt Amortiz
39900	OTHER TANGIBLE PROPERTY	0.00%	

PLANT THAT IS AMORTIZED (Depreciation rate is 0%)

	LAND RIGHTS & LEASEHOLD IMPROVEMENTS		
31101	LEASE HOLD IMPROVEMENTS - P&M BLDG	0.00%	
32000	LAND & LAND RIGHTS - NUCLEAR	0.00%	
32001	MISSOURI GROSS AFDC	0.00%	
34002	LAND RIGHTS - WIND	0.00%	
35001	LAND RIGHTS - TRANSMISSION	0.00%	
36001	LAND RIGHTS - DISTRIBUTION	0.00%	
38900	LAND & LAND RIGHTS - GENERAL	0.00%	
39003	Struct & Imprv - Leashold (801 Charlotte)	0.00%	
39004	Struct & Imprv - Leashold (Marshall)	0.00%	
39005	Struct & Imprv - Leashold (1KC Place)	0.00%	
	INTANGIBLE PLANT (to be Amortized)		
30100	ORGANIZATION	0.00%	
30200	FRANCHISES & CONSENTS	0.00%	
30301	INTANGIBLE SUBSTATION EQUIP (LIKE 353)	0.00%	
30302	5-YR SOFTWARE	0.00%	
30303	10-YR SOFTWARE	0.00%	
30304	INTANGIBLE COMMUNICATION EQUIP (LIKE 397)	0.00%	
30305	5-YR SOFTWARE-WOLF CREEK	0.00%	
303XX	Miscl Intang Plt - 15yr Software	0.00%	

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ACCT. NO.	DESCRIPTION	KANSAS JURISDICTION
30306	INTANGIBLE ACC EQUIP (LIKE 345)	0.00%
30307	Misc Intg Plt-Srct (Like 312)	0.00%
30308	Misc Intang Trans Line (Like 355)	0.00%
30309	Miscl Intang Trans Ln MINT Line	0.00%
30310	Misc Intang-Iatan Hwy & Bridge	0.00%
30311	Misc Intan-LaCygne Road Overpass	0.00%
30312	Misc Intan-Montrose Highway	0.00%
30313	Misc Intan-Radio Frequencies	0.00%

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Summary of Adjustments

Line No.	Adj No.	Description	Witness	Increase (Decrease)			
	A	B		D	E	F	G
				Adjust to 6-30-18 - Update Date			
	JURISDICTIONAL COST OF SERVICE			Total Adjustments	Allocated Adjs	100% MO & Whsl Adjs (2)	100% KS Adjs
				Incr (Decr)	Incr (Decr)	Incr (Decr)	Incr (Decr)
	Depreciation Expense						
	CS-120	Annualize depreciation expense based on jurisdictional depreciation rates applied to jurisdictional plant-in-service at indicated period	Klote	39,384,594	39,384,594		
				39,384,594	39,384,594	0	0
	Amortization Expense						
	CS-121	Annualize plant amortization expense based on jurisdictional amortization rates applied to unamortized jurisdictional plant-in-service at indicated period	Klote	9,709,293	9,709,293		
	CS-130	Amortize Customer Migration	Nunn	95,563			95,563
	CS-131	Amortize La Cygne BUD Plant Reg Liability	Nunn	(992,933)			(992,933)
	CS-132	Amortize La Cygne BUD Deferred Depreciation	Nunn	(5,833)			(5,833)
	CS-133	Amortize Wolf Creek BUD Plant Reg Liability	Nunn	(41,675)			(41,675)
				8,764,415	9,709,293	0	(944,878)

(1) All amounts are total company; if an adjustment is applicable to only KS or MO it is so indicated
(2) These adjustments affect Missouri and Wholesale jurisdic ions and are not discussed in testimony supporting the MIssouri rate case.

SECTION 11
TAXES

Filed in Accordance with K.A.R. 21-1-231(c)(4)(K)(i)

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TY 9/30/17; K&M 6/30/18

12 Month Revenues and O & M Expenses - Schedule 9

Line No.	Account No.	Description	Per Books Test Year	Rate Case Adj	Adjusted Balance	Juris Factor #	Juris Allocator	Electric Juris Adjusted Balance
	A	B	C	D	E	F	G	H
		OTHER OPERATING EXPENSES						
		Taxes Other Than Income Taxes-Allocated						
	408.100	KS Property Tax RIDER	(2,025,122)	2,025,122	0	100% KS	100.0000%	0
	408.103	Other Miscellaneous Taxes	2,808	0	2,808	PTD	46.2712%	1,299
	408.110	KCMO City Earnings Tax-100% MO	592,700	0	592,700	100% MO	0.0000%	0
	408.120	Property Tax	79,415,857	1,448,301	80,864,158	Elec Plt wo WC	46.1235%	37,297,346
	408.121	Property Tax - Wolf Creek	20,434,436	(757,066)	19,677,370	WC Plt	47.0659%	9,261,331
	408.130	Gross Receipts Tax-100% MO	70,188,095	0	70,188,095	100% MO	0.0000%	0
	408.140	Payroll Tax, incl Unemployment	12,165,441	489,200	12,654,641	Sal&Wg	46.4069%	5,872,632
	408.140	ORVIS - KS	41,152	(41,152)	(0)	100% KS	100.0000%	(0)
		TOTAL OTHER OPERATING EXPENSES	**180,815,367**	**3,164,405**	**183,979,772**			**52,432,608**
	409.100	**INCOME TAXES**						
		Current Income Taxes	69,211,672	15,103,075	84,314,747	Sch11		31,705,059
		TOTAL CURRENT INCOME TAXES	**69,211,672**	**15,103,075**	**84,314,747**			**31,705,059**
	410 & 411	**DEFERRED INCOME TAXES**						
		Deferred Income Taxes - Def. Inc. Tax.	52,303,590	(55,528,294)	(3,224,704)	Sch 11		(1,961,053)
		Amortization of Deferred ITC	(962,914)	(124,738)	(1,087,652)	Sch 11		(503,270)
		Amort of Excess Deferred Income Taxes		(2,478,027)	(2,478,027)	Sch 11		(1,146,613)
		Amort of Cost of Removal-ER-2007-0291	0	354,438	354,438	Sch 11		0
		TOTAL DEFERRED INCOME TAXES	**51,340,676**	**(57,776,621)**	**(6,435,945)**			**(3,610,936)**
		TOTAL INCOME TAXES	**120,552,348**	**(42,673,546)**	**77,878,802**			**28,094,123**

Kansas City Power & Light Company
2018 RATE CASE - DIRECT
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Summary of Tax Adjustments

Adj No.	Description	Witness	Increase (Decrease)			
A	B		D	E	F	G
			Adjust to 6-30-18 - Update Date			
JURISDICTIONAL COST OF SERVICE			Total Adjustments	Allocated Adjs	100% MO & Whsl Adjs (2)	100% KS Adjs
			Incr (Decr)	Incr (Decr)	Incr (Decr)	Incr (Decr)
Taxes Other than Income						
CS-53	Annualize FICA payroll tax expense	Klote	746,229	746,229		
CS-126	Adjust property tax expense	Klote	2,716,357	2,716,357		
			3,462,586	3,462,586	0	0
Income Tax Expense						
CS-125	Reflect adjustments to Schedule 9, Allocation of Current and Deferred Income Taxes	Klote	(42,673,546)	(43,027,984)	354,438	
			(42,673,546)	(43,027,984)	354,438	0

(1) All amounts are total company; if an adjustment is applicable to only KS or MO it is so indicated
(2) These adjustments affect Missouri and Wholesale jurisdictions and are not discussed in testimony supporting the MIssouri rate case.

Kansas City Power & Light Company
2018 RATE CASE - DIRECT
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Income Tax - Schedule 11

Line No.	Line Description	Total Company Balance *	Juris Factor #	Juris Allocator *	Tax Rate	(Jurisdictional) Adjusted with 7.384% Return
	A				B	C
1	Net Income Before Taxes (Sch 9)	448,871,405				175,849,606
2	***Add to Net Income Before Taxes:***					
3	Depreciation Exp	280,839,906				130,439,716
4	Plant Amortization Exp	43,414,113				20,088,233
5	Amortiz of Unrecovered Reserve - KS	2,777,263	100% KS	100.0000%		2,777,263
6	Book Nuclear Fuel Amortization	30,725,326				13,393,016
7	Transp & Unit Train Depr-Clearing (a)	4,777,669				2,234,347
8	50% Meals & Entertainment	585,681	Sal&Wg	46.4069%		271,797
9	**Total**	363,119,957				169,204,372
10	***Subtract from Net Income Before Taxes:***					
11	Interest Expense	129,313,161				57,820,208
12	IRS Tax Return Depreciation	269,555,020	PTD	46.2712%		124,726,356
13	IRS Tax Return Plant Amortization	43,732,738	PTD	46.2712%		20,235,665
14	IRS Tax Return Nuclear Amortization	22,659,583	E1	43.5895%		9,877,199
15	Cost of Removal Incurred on Pre-81 Property	9,593,542	PTD	46.2712%		4,439,047
16	Cost of Removal Provided for Pre-81 Property	(1,532,713)	PTD	46.2712%		(709,205)
17	Employee 401k ESOP Deduction	2,310,000	Sal&Wg	46.4069%		1,072,000
18	IRC Section 199 Domestic Production Activities	0	D1	47.0659%		0
19	**Total**	475,631,331				217,461,271
20	**Net Taxable Income**	336 360 032				127 592 708
21	**Provision for Federal Income Tax**					
22	Net Taxable Income	336,360,032				127,592,708
23	Deduct State Income Tax @ 100%	23,545,202			7.00%	8,931,490
24	Deduct City Income Tax	0				0
25	Federal Taxable Income	312,814,830				118,661,218
26	Federal Tax Before Tax Credits	65,691,114			21.00%	24,918,856
27	Less Tax Credits:					
28	Wind	(3,970,080)	E1	43.5895%		(1,730,538)
29	Research and Development	(875,000)	E1	43.5895%		(381,408)
30	Fuels Tax Credit	(76,489)	E1	43.5895%		(33,341)
31	**Total Federal Tax**	60 769 545				22 773 569
32	**Provision for State Income Tax**					
33	Net Taxable Income	336,360,032				127,592,708
34	Deduct Federal Income Tax @ 0%	0				0
35	Deduct City Income Tax	0				0
36	State Jurisdictional Taxable Income	336,360,032				127,592,708
37	**Total State Tax**	23 545 202			7.00%	8 931 490
38	**Provision for City Income Tax**					
39	Net Taxable Income	336,360,032				127,592,708
40	**Total City Tax**	0			0.00%	0
41	**Effective Tax rate before Tax Cr and Earnings Tax**	26.53%				26.53%
42	**Summary of Provision for Income Tax**					
43	Federal Income Tax	60,769,545				22,773,569
44	State Income Tax	23,545,202				8,931,490
45	City Income Tax	0				0
46	**Total Provision for Income Tax**	84,314,747				31,705,059
47	**Deferred Income Taxes**					
48	Deferred Income Taxes - Excess IRS Tax over Book D&A	(3,224,704)	See Computation Below			(1,961,053)
49	Amortization of Deferred ITC	(1,087,652)	PTD	46.2712%		(503,270)
50	Amort of Excess Deferred Income Taxes	(2,478,027)	PTD	46.2712%		(1,146,613)
51	Amortization of Cost of Removal-ER-2007-0291	354,438	100% MO	0.0000%		0
52	**Total Deferred Income Tax Expense**	(6,435,945)				(3,610,936)
53	**Total Income Tax**	77 878 802				28 094 123

Kansas City Power & Light Company
2018 RATE CASE - DIRECT
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Income Tax - Schedule 11

Line No.	Line Description	Total Company Balance *	Juris Factor #	Juris Allocator *	Tax Rate	(Jurisdictional) Adjusted with 7.384% Return
54	(a) Percent of vehicle depr clearing to O&M				41.7950%	

Interest Expense Proof

Total Rate Base (Sch. 2)	2,329,018,289
X Wtd Cost of Debt	2.483%
Interest Exp @ 12/31/07	57,820,208
Less: Interest Expense from Line 7	57,820,208
Difference	0

* As Needed

Note 1 If this cell contains a ref# error, delete the cell contents and re-enter the formula.
If (state tax > 0, state tax, 0)

Computation of Line 48 Above

Deferred Income Taxes - Excess IRS Tax over Book D&A:

Line No.	Line Description	Total Company Balance *	Juris Factor #	Juris Allocator *	Tax Rate	(Jurisdictional) Adjusted with 7.384% Return
55	RS Tax Return Depreciation	269,555,020				124,726,356
56	Less: Book Depreciation	283,617,169				133,216,979
57	Excess IRS Tax Depr over Book Depreciation	(14,062,149)				(8,490,624)
58	RS Tax Return Plant Amortization	43,732,738				20,235,665
59	Less: Book Amortization	43,414,113	PTD	46.2712%		20,088,233
60	Excess IRS Tax Amort over Book Amortization	318,625				147,432
61	RS Tax Return Nuclear Amortization	22,659,583				9,877,199
62	Less: Book Nuclear Amortization	30,725,326	E1	43.5895%		13,393,016
63	Excess IRS Tax Nuclear Amort over Book Nuclear Amort	(8,065,743)				(3,515,817)
64	Total Timing Differences	(21,809,266)				(11,859,009)
65	AFUDC Equity	9,220,127	PTD	46.2712%		4,266,264
66	ITC Coal Basis Adjustment	421,212	PTD	46.2712%		194,900
67	Miscellaneous Flow Through	12,994	PTD	46.2712%		6,012
68	Total Timing Differences after Flow Through	(12,154,933)				(7,391,833)
69	Effective Tax rate	26.53%				26.53%
70	**Deferred Income Taxes - Excess IRS Tax over Tax SL**	(3,224,704)				(1,961,053)

Kansas City Power & Light Company
Section 11 - Deferred Investment Tax Credits - Total Company & Kansas Jurisdictional
Source - FERC Form 1 page 266-267

Debits (Credits)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	Sep-15	12 Mo Ended Prior to Test Year Sep-16	Unadjusted Test Year Sep-17
10% ITC													
Charges	1,386,459	1,386,424	1,386,435	1,369,131	1,300,538	592,993	592,993	592,993	592,993	592,993		592,993	592,993
Adjustments	0	0	0	0	0	0	0	0	0	0		0	0
Credits	0	0	0	0	0	0	0	0	0	0		0	0
Ending Balance	(24,766,947)	(23,380,523)	(21,994,088)	(20,624,957)	(19,324,419)	(18,731,426)	(18,138,433)	(17,545,440)	(16,952,447)	(16,359,454)	(17,693,688)	(17,100,695)	(16,507,702)
15% ITC													
Charges			715,250	81,584	469,330	425,223	425,223	425,223	425,223	425,223		425,223	425,223
Adjustments			4,187,121	0	0	0	0	0	0	0		0	0
Credits	(74,236,945)	(37,237,676)	0	0	0	0	0	0	0	0		0	0
Ending Balance	(74,236,945)	(111,474,621)	(106,572,250)	(106,490,666)	(106,021,336)	(105,596,113)	(105,170,890)	(104,745,667)	(104,320,444)	(103,895,221)	(104,851,972)	(104,426,749)	(104,001,526)
30% ITC													
Charges						0	0	0	0	0		0	0
Adjustments						0	0	0	0	0		0	0
Credits						(211,474)	(65,196)	(20,963)	0	0		0	0
Ending Balance	0	0	0	0	0	(211,474)	(276,670)	(297,633)	(297,633)	(297,633)	(297,633)	(297,633)	(297,633)
Total ITC													
Charges	1,386,459	1,386,424	2,101,685	1,450,715	1,769,868	1,018,216	1,018,216	1,018,216	1,018,216	1,018,216		1,018,216	1,018,216
Adjustments	0	0	4,187,121	0	0	0	0	0	0	0		0	0
Credits	(74,236,945)	(37,237,676)	0	0	0	(211,474)	(65,196)	(20,963)	0	0		0	0
Ending Balance	(99,003,892)	(134,855,144)	(128,566,338)	(127,115,623)	(125,345,755)	(124,539,013)	(123,585,993)	(122,588,740)	(121,570,524)	(120,552,308)	(122,843,293)	(121,825,077)	(120,806,861)
		NonU ility	(794,850)	(764,006)	(733,162)	(787,708)	(756,864)	(1,237,862)	(1,207,018)	(1,176,174)	(1,245,573)	(1,214,729)	(1,183,885)
		Per Trial Balance	(129,361,188)	(127,879,629)	(126,078,917)	(125,326,721)	(124,342,857)	(123,826,602)	(122,777,542)	(121,728,482)	(124,088,866)	(123,039,806)	(121,990,746)

Filed in Accordance with K.A.R. 21-1-231(c)(4)(K)(v)

Kansas Jurisdictional ITC (Test Year and 12 Months Prior to Test Year)

			CS-125	Sch 11			CS-125	Sch 11
	12 Mos ended 9/30/16	**Adj**	**9/30/16 Kansas Basis**	**9/30/16 Kansas Juris**	**12 Mos ended 9/30/17**	**Adj**	**9/30/17 Kansas Basis**	**9/30/17 Kansas Juris**
10% ITC								
Beginning Bal	(17,693,688)	(3,029,956)	(20,723,644)		(17,100,695)	(2,956,509)	(20,057,204)	
Charges	592,993	73,447	666,440	305,363	592,993	73,447	666,440	308,370
Credits	0	0	0		0	0	0	
Ending Balance	(17,100,695)	(2,956,509)	(20,057,204)		(16,507,702)	(2,883,062)	(19,390,764)	
15% ITC								
Beginning Bal	(104,851,972)	14,609	(104,837,363)		(104,426,749)	10,598	(104,416,151)	
Charges	425,223	(4,011)	421,212	193,000	425,223	(4,011)	421,212	194,900
Adjustments	0	0	0		0	0		
Credits	0	0	0		0	0	0	
Ending Balance	(104,426,749)	10,598	(104,416,151)		(104,001,526)	6,587	(103,994,939)	
30% ITC								
Beginning Bal	(297,633)	0	(297,633)		(297,633)	0	(297,633)	
Charges	0	0	0	0	0	0	0	0
Credits	0	0	0		0	0	0	
Ending Balance	(297,633)	0	(297,633)		(297,633)	0	(297,633)	
Total ITC								
Beginning Bal	(122,843,293)	(3,015,347)	(125,858,640)		(121,825,077)	(2,945,911)	(124,473,355)	
Charges	1,018,216	69,436	1,087,652	498,363	1,018,216	69,436	1,087,652	503,270
Adjustments	0	0	0		0	0	0	
Credits	0	0	0		0	0	0	
Ending Balance	(121,825,077)	(2,945,911)	(124,770,988)		(120,806,861)	(2,876,475)	(123,385,703)	

NOTE: ITC coal credit in GL account 255750 is Non-Utility for Missouri purposes only. On the FERC report this credit is also classified as Non-Utility, however, for KS purposes, this credit is Utility related and it is included in the 15% ITC above.

Kansas City Power & Light Company
2018 RATE CASE - DIRECT
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Accumulated Deferred Income Tax Reserves - Schedule 13

LINE NO.	Account No.	Line Description	RB-125 Direct/Update KS ADIT Balance	RB-82 TDC Adjustment	Adjusted Balance	Juris Factor #	Juris Allocator	Juris Adjusted Balance
	A	B	E	E	E	F	G	H
1	190	**ACCT 190 ACCUM DEFERRED TAX**						
2		Misc			0	PTD	46.2712%	0
3		Net Operating Loss	(197,147,669)	8,204,805	(188,942,864)	PTD	46.2712%	(87,426,140)
4		Vacation & Other Salaries & Wages Alloc			0	Sal&Wg	46.4069%	0
5		Advertising			0	100% MO	0.0000%	0
6		Nuclear Fuel			0	E1	43.5895%	0
7		**TOTAL ACCT 190**	(197,147,669)	8,204,805	(188,942,864)			(87,426,140)
8								
9	282	**LIBERALIZED DEPRECIATION**						
10		Method/Life Depreciation - Non Wolf Creek	1,080,378,285	(44,962,708)	1,035,415,577	D1	47.0659%	487,327,660
11		Method/Life Depreciation - Wolf Creek	174,133,006	0	174,133,006	D1	47.0659%	81,957,266
12		Nuclear Fuel	(2,613,792)	0	(2,613,792)	E1	43.5895%	(1,139,339)
13		Other DIT Adj for Post June 2018 Method/Life	12,993,424	(540,755)	12,452,669	D1	47.0659%	5,860,961
14		**TOTAL LIBERALIZED DEPRECIATION**	1,264,890,923	(45,503,463)	1,219,387,460			574,006,548
15								
16		**ACCUM DIT ON BASIS DIFFERENCES**						
17		Gross AFUDC - Wolf Creek Construc ion	6,460,291	0	6,460,291	100% MO	0.0000%	0
18		AFUDC Debt/Cap Int - W/O Fuel & Wolf Creek Constr	(26,213,464)	1,090,940	(25,122,524)	D1	47.0659%	(11,824,142)
19		AFUDC Debt - Nuclear Fuel	213,139	0	213,139	E1	43.5895%	92,906
20		Contributions in Aid of Construction	(33,079,165)	0	(33,079,165)	D1	47.0659%	(15,569,007)
21		Repair Allowance	41,774,499	(1,738,553)	40,035,946	D1	47.0659%	18,843,278
22		Repair Expense - Wolf Creek	67,475,184	0	67,475,184	D1	47.0659%	31,757,803
23		Repair Expense - Produc ion	193,604,696	0	193,604,696	D1	47.0659%	91,121,793
24		Pensions Capitalized - Assigned		0	0	100% KS	100.0000%	0
25		Pensions Capitalized - Allocated		0	0	D1	47.0659%	0
26		Payroll Tax Capitalized - Assigned		0	0	100% KS	100.0000%	0
27		Payroll Tax Capitalized - Allocated		0	0	D1	47.0659%	0
28		Prop Tax Capitalized - Assigned - Wolf Creek		0	0	100% KS	100.0000%	0
29		Prop Tax Capitalized - Assigned - MO	2,118,312	0	2,118,312	100% MO	0.0000%	0
30		Prop Tax Capitalized - Allocated - Wolf Creek			0	D1	47.0659%	0
31		Prop Tax Capitalized - Allocated	2,976	(124)	2,852	D1	47.0659%	1,342
32		Health & Welfare Capitalized	64,679	(2,692)	61,987	D1	47.0659%	29,175
33		Other Miscellaneous	101,925,856	(4,241,905)	97,683,951	D1	47.0659%	45,975,831
34		**TOTAL ACCUM DIT ON BASIS DIFFERENCES**	354,347,003	(4,892,333)	349,454,670			160,428,979
35								
36		**TOTAL ACCT 282**	1,619,237,926	(50,395,796)	1,568,842,130			734,435,527
37								
38	283	**MISC DEFERRED INCOME TAX (RATEBASE ITEMS)**						
39		Prior Years Depr ADJ & Other Total Plant	(7,737,844)	322,030	(7,415,814)	D1	47.0659%	(3,490,320)
40		Refueling Outage & Other items with E1 Allocator	4,015,031	0	4,015,031	E1	43.5895%	1,750,132
41		Postretirement Benefits & Other Salaries & Wages	(28,424,678)	565,842	(27,858,836)	Sal&Wg	46.4069%	(12,928,434)
42		Customer Demand Prog & Other 100% MO	0	0	0	100% MO	0.0000%	0
43		Customer Demand Prog & Other 100% KS	(2,003,092)	0	(2,003,092)	100% KS	100.0000%	(2,003,092)
44		**TOTAL ACCT 283**	(34,150,583)	887,872	(33,262,711)			(16,671,714)
45								
46								
47		**TOTAL ACCUMULATED DEFERRED TAXES**	1,387,939,674	(41,303,120)	1,346,636,554			630,337,674

Filed in Accordance with K A R 21-1-231(c)(4)(K)(vi)

Kansas City Power & Light Company
Section 11 - Analysis of Deferred Income Taxes - Total Company
Source - FERC Form 1 page 234 and 272-277

Debits (Credits)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	Sep-15	12 Mo Ended Prior to Test Year Sep-16	Unadjusted Test Year Sep-17
Account 190 - Current (a)													
Restatement (b)													
Charges	180,337,196	141,398,150	47,883,092	93,089,042	16,699,863	15,526,734	40,379,002	155,210,467	11,447,621	159,642,894		140,637,675	11,579,101
Credits	0	(1,254,126)	(17,824,924)	(71,857,165)	(3,264,312)	(6,521,512)	(1,412,418)	(851,729)	(18,928,500)	(121,522,800)		(16,211,214)	(3,703,844)
Ending Balance	328 810 079	468 954 103	499 012 271	520 244 148	533 679 699	542 684 921	581 651 505	736 010 243	728 529 364	766 649 458	607 453 209	731 879 670	739 754 927
A/C281 - Accel Amort Prop													
Reclass from 282				(32,565,573)									
Charges				0	0	0	0	0	0	30,265,249			
Credits				0	(3,433,996)	(14,795,109)	(14,795,956)	(16,290,973)	(7,884,351)	(7,455,373)		(14,521,222)	(2,406,070)
Ending Balance	0	0	0	(32 565 573)	(35 999 569)	(50 794 678)	(65 590 634)	(81 881 607)	(89 765 958)	(66 956 082)	(78 790 859)	(93 312 081)	(95 718 151)
A/C282 - Other Property													
Reclass to 281				32,565,573									
Charges	0	111,831	19,521,080	339,018	4,534,685	3,331,022	3,512,709	0	5,697,277	548,339,423		0	4,944,696
Credits	(108,207,428)	(94,851,222)	(144,690,499)	(72,776,101)	(83,576,011)	(71,579,532)	(132,014,801)	(240,675,153)	(82,764,309)	(66,638,424)		(277,589,712)	(50,653,385)
Ending Balance	(812 372 937)	(907 112 328)	(1 032 281 747)	(1 072 153 257)	(1 151 194 583)	(1 219 443 093)	(1 347 945 185)	(1 588 620 338)	(1 665 687 370)	(1 183 986 371)	(1 382 549 165)	(1 660 138 877)	(1 705 847 566)
A/C 283 - Other													
Restatement (b)													
Charges	66,693,080	35,468,305	23,710,353	88,506,919	9,215,649	18,300,097	44,386,920	40,747,088	53,560,896	138,004,366		15,034,194	4,751
Credits	(89,309,199)	(52,781,120)	(54,249,658)	(113,391,473)	(1,135,742)	(25,719,616)	(28,088,964)	(59,117,112)	(56,798,935)	(68,282,383)		(8,194,042)	(16,906,941)
Ending Balance	(121 412 299)	(138 725 114)	(169 264 419)	(194 148 973)	(186 069 066)	(193 488 585)	(177 190 629)	(195 560 653)	(198 798 692)	(129 076 709)	(192 355 357)	(185 515 205)	(202 417 395)
												(185,515,205)	(202,417,395)
Total Electric Deferred Income Tax													
Restatement (b)				0	0	0	0	0	0	0		0	0
Charges	247,030,276	176,978,286	91,114,525	181,934,979	30,450,197	37,157,853	88,278,631	195,957,555	70,705,794	876,251,932		155,671,869	16,528,548
Credits	(197,516,627)	(148,886,468)	(216,765,081)	(258,024,739)	(91,410,061)	(118,615,769)	(176,312,139)	(316,934,967)	(166,376,095)	(263,898,980)		(316,516,190)	(73,670,240)
Ending Balance	(604 975 157)	(576 883 339)	(702 533 895)	(778 623 655)	(839 583 519)	(921 041 435)	(1 009 074 943)	(1 130 052 355)	(1 225 722 656)	(613 369 704)	(1 046 242 172)	(1 207 086 493)	(1 264 228 185)
			a/c 253 *	(157,898)	0	0	0	0	0	0	0	0	0
			Per Trial Balance	(778,781,553)	(839,583,519)	(921,041,435)	(1,009,074,943)	(1,130,052,355)	(1,225,722,656)	(613,369,704)	(1,046,242,172)	(1,207,086,493)	(1,264,228,185)

Filed in Accordance with K A R 21-1-231(c)(4)(K)(vi)

Kansas Jurisdictional Deferred Income Taxes (Test Year and 12 Months Prior to Test Year)

*Differences relate to accruals in acct 283300 for uncertain state tax positions that are not related to temporary differences, therefore they are reclassified to acct 253 for FERC reporting.

							Rev Req Mod Test Period	Test Period X adjusted alloc factor
	12 Mos ended 9/30/16	**Adj**	**9/30/16 Kansas Basis**	**9/30/16 Kansas Juris**	**12 Mos ended 9/30/17**	**Adj**	**9/30/17 Kansas Basis**	**9/30/17 Kansas Juris**
A/C 190								
Beginning Bal	607,453,209				731,879,670			
Restatement (b)	0				0			
Charges	140,637,675				11,579,101			
Credits	(16,211,214)				(3,703,844)			
Ending Balance	731,879,670	12,229,352	744,109,022	340,976,683	739,754,927	12,360,944	752,115,871	348,013,077
A/C 281								
Beginning Bal	(78,790,859)				(93,312,081)			
Reclass from 282	0				0			
Charges	0				0			
Credits	(14,521,222)				(2,406,070)			
Ending Balance	(93 312 081)	(1 559 199)	(94 871 280)	(43 576 968)	(95 718 151)	(1 599 404)	(97 317 555)	(45 558 102)
A/C 282								
Beginning Bal	(1,382,549,165)				(1,660,138,877)			
Reclass to 281	0				0			
Charges	0				4,944,696			
Credits	(277,589,712)				(50,653,385)			
Ending Balance	(1 660 138 877)	(27 740 110)	(1 687 878 987)	(775 288 878)	(1 705 847 566)	(28 503 880)	(1 734 351 446)	(811 916 823)
A/C 283								
Beginning Bal	(192,355,357)				(185,515,205)			
Charges	15,034,194				4,751			
Credits	(8,194,042)				(16,906,941)			
Ending Balance	(185 515 205)	(3 099 868)	(188 615 073)	(95 158 867)	(202 417 395)	(3 382 296)	(205 799 691)	(103 149 547)
Total DIT								
Beginning Bal	(1,046,242,172)				(1,207,086,493)			
Charges	155,671,869				16,528,548			
Credits	(316,516,190)				(73,670,240)			
Ending Balance	(1 207 086 493)	(20,169,826)	(1,227,256,319)	(573,048,030)	(1,264,228,185)	(21,124,635)	(1,285,352,820)	(612,611,396)

Notes: Accumulated Deferred Income Taxes, as recorded, include amounts relating to FAS 109.

a) Balances for deferred income tax reserve accounts shown above include reclassifications between reserve accounts for FERC Form 1 presentation only in compliance with FERC Order FA96-19-000. Such reclassifications are not recorded on the financial books.

b) 2006 Deferred Income Tax Reserve beginning balances reflect the restatement of tax accounts related to change in accounting method for Nuclear Refueling Outage.

(1) Deferred taxes on pollution control facilities subject to accelerated amortization were reclassified from account 282 to account 281 on the 2011 FERC Form 1.

SECTION 12

ALLOCATION RATIOS

Kansas City Power & Light Company
2018 RATE CASE - DIRECT
Kansas Jurisdiction
TY 9/30/17; K&M 6/30/18

Rate Case Utility Allocation Factors

		Jurisdictional Allocators			
Jurisdiction Factors		**KS Retail**	**MO Retail**	**Non Juris / Wholesale**	**Total**
100% MO	Missouri Jurisdictional	0.0000 %	100.0000 %	0.0000 %	100.0000 %
100% KS	Kansas Jurisdictional	100.0000 %	0.0000 %	0.0000 %	100.0000 %
NonJur/Wh	Non Jurisdictional/Wholesale	0.0000 %	0.0000 %	100.0000 %	100.0000 %
D1	D1 - Demand (Capacity) Factor	47.0659 %	52.7850 %	0.1491 %	100.0000 %
E1	E1 - Energy Factor with Losses (E1)	43.5895 %	56.2443 %	0.1662 %	100.0000 %
UE1	UE1 - Unused Energy Factor	49.5844 %	n/a	n/a	
C1	C1 - Customer - Elec (Retail only) (C1)	47.3951 %	52.6049 %	0.0000 %	100.0000 %
Blended Factors (See Calculation Below)		**KS**	**MO & Whsl**		
Sal&Wg	Sal & Wg - Salaries & Wages w/o A&G	46.4069 %	53.5931 %		100.0000 %
PTD	PTD - Prod/Trsm/Dist Plant (excl Gen)	46.2712 %	53.7288 %		100.0000 %
Dist Plt	Dist Plt - Weighted Situs Basis	44.3024 %	55.6976 %		100.0000 %
Elec Plt wo WC	Total Plant without Wolf Creek	46.1235 %	53.8765 %		100.0000 %
WC Plt	Wolf Creek Plant	47.0659 %	52.9341 %		100.0000 %
Situs Basis Plant used for Dist Depr Reserve		**KS Retail**	**MO Retail**	**Non Juris / Wholesale**	
360L	360 - Dist Land	49.6091 %	50.3909 %	0.0000 %	100.0000 %
360LR	360 - Dist Land Rights	41.6676 %	58.3324 %	0.0000 %	100.0000 %
361	361 - Dist Structures & Improvements	43.2654 %	56.7346 %	0.0000 %	100.0000 %
362	362 - Distr Station Equipment	37.8780 %	62.1220 %	0.0000 %	100.0000 %
362Com	362 - Distr Station Equip-Communication	44.1679 %	55.8321 %	0.0000 %	100.0000 %
363	363 - Distr Energy Storage Equipment	0.0000 %	100.0000 %	0.0000 %	100.0000 %
364	364 - Dist Poles, Towers & Fixtures	45.2245 %	54.7755 %	0.0000 %	100.0000 %
365	365 - Dist Overhead Conductor	43.3827 %	56.6173 %	0.0000 %	100.0000 %
366	366 - Dist Underground Circuits	42.0307 %	57.9693 %	0.0000 %	100.0000 %
367	367 - Dist Underground Conduct & Devices	47.2175 %	52.7825 %	0.0000 %	100.0000 %
368	368 - Dist Line Transformers	43.2615 %	56.7385 %	0.0000 %	100.0000 %
369	369 - Dist Services	48.3424 %	51.6576 %	0.0000 %	100.0000 %
370	370 - Dist Meters	47.8273 %	52.1727 %	0.0000 %	100.0000 %
370AMI	370 - Dist AMI Meters	45.5216 %	54.4784 %	0.0000 %	100.0000 %
371	371 - Dist Customer Premise Installations	31.4016 %	68.5984 %	0.0000 %	100.0000 %
371CCN	371 - Dist Electric Vehicle Charging Stations	47.4444 %	52.5556 %	0.0000 %	100.0000 %
373	373 - Dist Street Lights & Traffic Signals	52.6596 %	47.3404 %	0.0000 %	100.0000 %

Filed in Accordance with K.A.R. 21-1-231-(c)(4)(L)

Rate Case Utility Allocation Factors

Jurisdictional Allocators

Calc of PTD Allocation Factor	Per Schedule 3 Total Adj Plant	KS Juris
Total Production Plant	6,406,125,353	3,012,068,884
Total Transmission Plant	86,547,296	40,734,264
Total Distr bution Plant	2,435,184,174	1,078,223,781
Total Prod, Transm & Dist Plant	8,927,856,823	4,131,026,929
Total PTD Allocation Factor		46.2712 %

Calc of Elec Plt wo WC and WC Plt Allocation Factors	Per Schedule 3 Total Adj Plant	KS Juris	Juris Alloc
Total Plant	9,906,396,780	4,586,347,518	
Total Nuclear Production Plant	1,822,364,062	857,712,047	47.0659 %
Total Plant without Nuclear Plant	8,084,032,718	3,728,635,471	46.1235 %

Calculation of Salaries and Wages Allocation Factor Elec Oper & Mtce Labor	COSCLAS Test Year Labor	Factor	Juris Allocator	KS Juris
Production - Demand Related	92,048,898	D1	47.0659 %	43,323,642
Production - Energy Related Related	8,531,945	E1	43.5895 %	3,719,032
Transmission	3,452,637	D1	47.0659 %	1,625,015
Distr bution	23,675,245	Dist Plt	44.3024 %	10,488,695
Customer Accounts	9,445,143	C1	47.3951 %	4,476,535
Customer Services	1,267,953	C1	47.3951 %	600,948
Sales	350,924	C1	47.3951 %	166,321
Subtotal Salaries & Wages W/O A&G	138,772,745		46.4069 %	64,400,187
Administrative & General	28,278,686	Sal&Wg	46.4069 %	13,123,273
TOTAL LABOR	167,051,431			77,523,460

Rate Case Utility Allocation Factors

Jurisdictional Allocators

Situs Distribution Allocation Factors

	Total	Sch 3 Distrib Situs Missouri	Sch 3 Distrib Situs Kansas	Juris Allocators Missouri	Juris Allocators Kansas	
36000 - Dist Land	9,267,377	4,669,913	4,597,464	50.3909 %	49.6091 %	
36001 - Dist Land Rights	16,589,694	9,677,160	6,912,534	58.3324 %	41.6676 %	
36100 - Dist Structures & Improvements	14,957,736	8,486,206	6,471,530	56.7346 %	43.2654 %	
36200 - Distr Station Equipment	233,970,661	145,347,343	88,623,318	62.1220 %	37.8780 %	
36203 - Distr Station Equip-Communication	4,682,147	2,614,142	2,068,005	55.8321 %	44.1679 %	
36300 - Distr Energy Storage Equipment	2,413,035	2,413,035		100.0000 %	0.0000 %	
36400 - Dist Poles, Towers & Fixtures	369,264,008	202,266,183	166,997,825	54.7755 %	45.2245 %	
36500 - Dist Overhead Conductor	265,503,686	150,321,020	115,182,666	56.6173 %	43.3827 %	
36600 - Dist Underground Circuits	292,261,273	169,421,960	122,839,313	57.9693 %	42.0307 %	
36700 - Dist Underground Conduc & Devices	540,704,388	285,397,467	255,306,921	52.7825 %	47.2175 %	
36800 - Dist Line Transformers	310,772,276	176,327,483	134,444,793	56.7385 %	43.2615 %	
36900 - Dist Services	149,683,863	77,323,116	72,360,747	51.6576 %	48.3424 %	
37000 - Dist Meters	54,745,052	28,561,957	26,183,096	52.1727 %	47.8273 %	
37001 - Distr AMI Meters	62,056,906	33,807,585	28,249,321	54.4784 %	45.5216 %	
37100 - Dist Customer Premise Installations	14,759,247	10,124,613	4,634,634	68.5984 %	31.4016 %	Removed CCN Sept Bal Rem
37101 - Dist Electric Vehicle Charging Stations	11,847,840	6,226,705	5,621,135	52.5556 %	47.4444 %	Added CCN Sept 17 Bal
37300 - Dist Street Lights & Traffic Signals	25,771,107	12,200,147	13,570,960	47.3404 %	52.6596 %	
Total by Jurisdiction	2,379,250,296	1,325,186,034	1,054,064,262			
Total Dist Plant - Weighted Situs	2,379,250,296	1,325,186,034	1,054,064,262	55.6976 %	44.3024 %	

KANSAS CITY POWER & LIGHT COMPANY
DESCRIPTION OF ALLOCATORS

OVERVIEW

KCPL does not have separate operating systems for its Kansas, Missouri and firm wholesale jurisdictions. It operates a single production and transmission system that is used to provide service to retail customers in Kansas and Missouri as well as the full-requirements firm wholesale customers.

The method of allocation is critical first to ensure that the rates charged to each jurisdiction of customers reflect the full cost of serving those customers but not the cost of serving customers in other jurisdictions. Secondly, the method of allocation must allow the Company the opportunity to recover fully its prudent costs of serving those customers. If the sum of the allocation factors allowed in each jurisdiction is less than 100%, then the Company is unable to recover its prudent cost of service and return on rate base.

The allocators that were utilized can be classified as "input" allocators or "calculated" allocators. The input allocators are based on the weather-normalized demand, energy, and customer information. The calculated allocators are, at their root, based on the Demand, Energy, and Customer allocators. The calculated allocators are, however, calculated within the Revenue Requirement Model. They are often calculated as combinations of amounts that have previously been allocated using one or more of the input allocators.

DESCRIPTION OF INPUT ALLOCATORS

The Demand allocator is a 12-month weather normalized average of the coincident peak demands for the Missouri and Kansas retail jurisdictional customers and the firm wholesale FERC jurisdictional customers.

The Energy allocator is based on the total weather normalized kilowatt-hour usage by the Kansas and Missouri retail customers and the firm wholesale jurisdiction.

The Customer allocator is based on the average number of customers in the Kansas, Missouri, and the firm wholesale jurisdiction.

APPLICATION OF ALLOCATORS
NET ELECTRIC OPERATING INCOME

Revenues
Retail revenues are the revenues received from retail customers in Kansas and Missouri. Retail revenues are not allocated; rather, they are recorded by jurisdiction.

Miscellaneous revenues include forfeited discounts, miscellaneous services, rent from electric property, transmission service for others, and other electric revenues. These miscellaneous revenues are subdivided and, where possible, assigned directly to the jurisdiction where they are recorded. The miscellaneous revenues that are not directly assignable to a jurisdiction are grouped by functional categories and allocated on a basis consistent with that functional category.

Non-firm off-system sales margins are allocated based on an Unused Energy allocator.

Non-firm off-system cost of sales and firm bulk sales revenue are allocated based on the Energy allocator.

Sales for resale revenue is revenue from the full-requirements firm wholesale customers under FERC jurisdiction. This revenue is assigned totally to the FERC jurisdiction.

Fuel & Purchased Power Costs
Fuel & Purchased Power costs are primarily allocated based on the Energy allocator. The exception is that the amortization of SO2 Allowances are assigned directly to the applicable jurisdiction.

Non-Fuel Operations and Maintenance Costs
Production O&M costs are allocated consistent with the allocation of production plant.

Transmission O&M costs associated with company owned transmission plant are allocated consistent with the allocation of transmission plant. Transmission Operation Load expense, Transmission of electricity by others and costs associated with participation in SPP are allocated based upon the Energy allocator.

Distribution O&M costs are allocated consistent with the allocation of distribution plant.

Customer accounts expenses are primarily allocated using the Customer allocator. The exception is that the uncollectible accounts expense and interest on Customer Deposits are assigned directly to the applicable jurisdiction.

Customer services and information expenses are primarily allocated using the Customer allocator. The exception is that the MEEIA and KEEIA expense as well as the amortization of Customer Programs are assigned directly to the applicable jurisdiction.

Sales expenses are primarily allocated using the Customer allocator.

A&G expenses are allocated using a number of methods depending on the cause of the cost. Salaries, employee benefits, and injuries and damages expenses are allocated based on the allocated sum of the labor portion of the production, transmission, distribution, customer accounts, customer services and information, and sales expenses described previously. Regulatory expenses are assigned directly to the applicable jurisdiction, with the exception of the FERC regulatory expense, which is allocated based on the Energy allocator. Amortization of other jurisdictional costs deferred as a result of prior regulatory orders are assigned directly to the applicable jurisdiction. Property insurance and General plant maintenance are allocated based on the composite allocation of production, distribution and transmission plant. Fleet expense is allocated based on the allocation of distribution plant. General advertising expense is allocated using the Customer allocator. The remaining A&G expenses are allocated using the Energy allocator.

Depreciation and Amortization Expenses

Depreciation expense is allocated based on the allocation of the corresponding plant. Amortization expense is allocated based on the composite allocation of production, transmission and distribution plant, with the exception of amortizations resulting from a prior regulatory order. These are assigned directly to the applicable jurisdiction.

Taxes

Non-Wolf Creek property tax is allocated based on Total Plant without Nuclear Plant and Wolf Creek property tax is allocated based on Nuclear plant only. Payroll tax is allocated based on the allocated sum of the labor portion of the production, transmission, distribution, customer accounts, customer services and information, and sales expenses. Other miscellaneous taxes are allocated based on the composite allocation of production, transmission and distribution plant.

Currently payable income tax is not allocated. Instead, currently payable income tax is calculated in the Revenue Requirement Model using the statutory tax rates for the appropriate jurisdiction and applying those rates to jurisdictional taxable income calculated in the Revenue Requirement Model. Deferred tax expense related to depreciation is calculated using the statutory federal and state tax rates for the appropriate jurisdiction and applying a composite tax rate to the jurisdictional difference between tax return depreciation and book depreciation reflected in the Revenue Requirement Model. Other deferred income tax expenses are allocated based on the composite allocation of production, transmission and distribution plant, with the exception of amortizations resulting from a prior regulatory order. These are assigned directly to the applicable jurisdiction.

RATE BASE

Plant-in-Service and Reserve for Depreciation and Amortization
The Demand allocator is used to allocate production plant. The exception is for plant items that have been afforded different jurisdictional accounting treatment through past commission orders. Examples include the Iatan 1 and Iatan 2 plant disallowances. These items are assigned directly to the applicable jurisdiction.

Transmission plant is allocated using the Demand allocator.

Distribution plant is assigned based on physical location.

General plant is allocated based on the composite allocation of production, transmission, and distribution plant.

Intangible plant consisting primarily of capitalized software is allocated based on the allocation factor considered most appropriate for the function of the software. For example, the customer information system is allocated based on the Customer allocation factor, whereas transmission-related software is allocated consistent with the allocation of Transmission plant.

The reserves for accumulated depreciation and amortization are allocated based on the allocation of the plant with which they are associated. The exception is for reserve items that have been afforded different jurisdictional accounting treatment through past commission orders. Examples include Additional Credit Ratio Amortizations which were assigned to specific reserve plant accounts in each jurisdiction differently and therefore are assigned directly to the applicable jurisdiction. In addition, Kansas unrecovered reserve amounts are allocated directly to Kansas.

Working Capital
Cash working capital ("CWC") is not allocated. Instead, the CWC amounts are calculated in the Revenue Requirement Model by taking the net CWC factors and applying these factors to allocated jurisdictional amounts in the Revenue Requirement Model. Fuel inventory is allocated using the Energy allocator. Materials and supplies ("M&S") and prepayments are grouped by function and allocated based on allocations appropriate for the function of the M&S and prepayments.

Regulatory assets and Regulatory Liabilities
Regulatory assets and regulatory liabilities are assigned directly to the applicable jurisdiction. There is one exception, S02 Emission Allowances for EPA auction proceeds, which are allocated based on the Energy Allocator.

Accumulated Reserve for Deferred Taxes

Plant related reserve is primarily allocated based on the allocation of plant with which it is associated. Non-Plant related reserve not directly assignable to a jurisdiction are grouped by functional categories and allocated on a basis consistent with that functional category. Deferred tax reserve amounts that are associated with regulatory assets and liabilities are assigned directly to the applicable jurisdiction.

Customer Advances for Construction and Customer Deposits

Customer advances for construction and customer deposits are assigned directly to the applicable jurisdiction.

SECTION 13

ANNUAL REPORT TO STOCKHOLDERS AND THE U.S. SECURITIES AND EXCHANGE COMMISSION

GREAT PLAINS ENERGY

BRIGHT / OUR ENERGY FUTURE

2016 ANNUAL REPORT

SELECTED FINANCIAL DATA

Year Ended December 31		2016		2015		2014[a]		2013[a]		2012[a]
(Dollars in millions except per share amounts)										
GREAT PLAINS ENERGY										
Operating revenues	**$**	**2,676**	$	2,502	$	2,568	$	2,446	$	2,310
Net income	**$**	**290**	$	213	$	243	$	250	$	200
Basic earnings per common share	**$**	**1.61**	$	1.37	$	1.57	$	1.62	$	1.36
Diluted earnings pe ommon share	**$**	**1.61**	$	1.37	$	1.57	$	1.62	$	1.35
Total assets at year end [a]	**$**	**13,570**	$	10,739	$	10,453	$	9,770	$	9,626
Total rede mable preferred stock, mandatorily rede mable preferred securities and long-t rm debt (cluding current maturities) [a]	**$**	**3,747**	$	3,746	$	3,481	$	3,492	$	2,999
Cash dividends per common share	**$**	**1.0625**	$	0.9975	$	0.935	$	0.8825	$	0.855
SEC ratio of earnings t combined fixed ch ges and preferred dividend requirements		**2.54**		2.58		2.72		2.75		2.31
KCP&L										
Operating revenues	**$**	**1,875**	$	1,714	$	1,731	$	1,671	$	1,580
Net income	**$**	**225**	$	153	$	162	$	169	$	142
Total assets at year end [a]	**$**	**8,058**	$	7,815	$	7,495	$	6,821	$	6,689
Total rede mable preferred stock, mandatorily rede mable preferred securities and long-t rm debt (cluding current maturities) [a]	**$**	**2,565**	$	2,563	$	2,297	$	2,294	$	1,887
SEC ratio of earnings to fixed charges		**3.30**		2.57		2.69		2.76		2.58

[a] Adjusted for ad ption of Accounting Standard Update (ASU) No. 2015-03, S mpl fying the Presentation of Debt Issuance Costs.

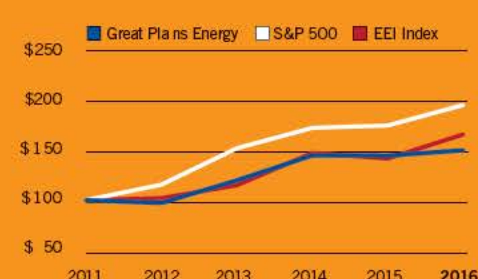
GREAT PLAINS ENERGY OPERATING REVENUES

(Dollars in millions)

STOCK PERFORMANCE GRAPH

(Dollars)

Comparison of Cumulative Total Returns* of Great P ains Energy, S&P 500 Index and EEI Index



**Total Retu n assumes reinvestment of d vidends. Assumes $100, invested on December 3 , 2011, in Great Plains Energy common stock, S&P 500 In ex and EEI Index.*

BY EXECUTING UPON OUR PROVEN STRATEGY OF BEST-IN-CLASS OPERATIONS, ENHANCED CUSTOMER ENGAGEMENT AND GROWTH THROUGH TARGETED INVESTMENTS, GREAT PLAINS ENERGY IS PREPARING FOR THE REGION'S BRIGHT ENERGY FUTURE.

An important part of our culture at Great Plains Energy is our commitment to our communities and the environment.

“OUR INDUSTRY CONTINUES TO SEE A TRANSITION IN BOTH CUSTOMER EXPECTATIONS AND THEIR NEEDS. AS OUR CUSTOMERS HAVE BECOME MORE DEPENDENT ON ELECTRICITY, THEY HAVE ALSO BECOME MORE EFFICIENT IN THEIR USAGE.”

TO OUR SHAREHOLDERS

BRIGHT. THE FUTURE OF OUR COMPANY AND OUR INDUSTRY

2016 was an exciting and busy year for Great Plains Energy, our region and our industry. After completing the last of the rate cases representing a ten-year cycle of generation and environmental construction, our performance in 2016 was confirmation of the strong foundation we worked so hard to establish with customers and shareholders. Although actual demand growth was lower than expected, management of our operating and maintenance expenses, returns on our Missouri Energy Efficiency Investment Act investments and favorable weather all contributed to strong financial performance. Much of this is the result of a strategy to invest in larger, more efficient generating plants and add new renewable and energy efficient opportunities. Going forward, we will continue to work in both Kansas and Missouri to establish mechanisms for timely recovery of investments and expenses.

With this same long-term strategy in mind, we announced on May 29, 2016, the acquisition of Westar, our neighboring utility in Kansas and partner in not only the Wolf Creek nuclear power plant, but also the La Cygne and Jeffery Energy Center generating stations. While we were not convinced that a transaction to increase in size was necessary to be successful, the opportunity to combine with Westar was compelling. Although confident in our stand-alone plan, a combination with Westar presented a very unique opportunity. Like us, Westar is a strong utility having finished a construction cycle similar to ours. After a strategic evaluation, Westar chose Great Plains Energy as presenting the best merger opportunity for their shareholders, customers and employees. Since the announcement, we have spent much time with shareholders, regulators, legislators, our communities and customers discussing the significant opportunities for savings and growth ahead for the most exciting utility combination in our region. The ability to save billions of dollars in costs and maintain a local focus on customers and communities will be unmatched by any other utility. As we work to finalize regulatory approvals we anticipate closing the transaction in the second quarter of 2017.

RESPONSIVE /

We believe in connecting with customers to help them better utilize our products. We are developing innovative solutions to allow us to better interact with our customers and communities. Through our energy efficiency initiatives we are delivering solutions that are beneficial to customers.

INNOVATE - SHAPING OUR INDUSTRY AND OUR REGION

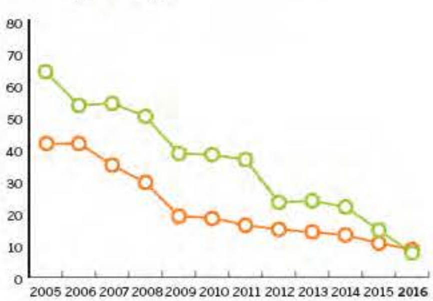
Our industry continues to see a transition in both customer expectations and their needs. As our customers have become more dependent on electricity, they have also become more efficient in their usage. Due to this increased efficiency, demand growth in our industry has flattened dramatically across the country. We see this as an opportunity to distinguish ourselves rather than a negative. During the past several years, we have worked to pass energy efficiency legislation in Missouri and helped create the rules at the Missouri Public Service Commission that allows us to offer energy efficiency products to our customers. In 2015, we worked to pass a similar law in Kansas and expect to expand energy-saving programs to customers through the Kansas Energy Efficiency Investment Act. During the meetings with customers and communities to review the merger process, the desire for economic development and energy efficiency programs was a common theme. We also continued to build out our electric vehicle charging network in both Missouri and Kansas. Our legislative focus, offering of energy efficient products and services and the building of our charging network have been done with an eye toward meeting changing customer needs while providing consistent shareholder returns.

In addition to our state-regulated utility returns, we continue to make advances in the competitive transmission market through Transource Energy, LLC ("Transource"), our partnership with American Electric Power. Transource recently completed the second and larger of its Missouri transmission projects. The new transmission line is expected to deliver power more efficiently to customers and has enabled the addition of 500 megawatts of new wind generation resources. Transource has also participated in numerous competitive transmission planning opportunities and recently won a substantial project in the PJM region. Transource's portfolio of transmission projects now totals more than $600 million and it is well positioned to grow its presence in the growing competitive transmission market.

ENVIRONMENTAL AND SOCIAL RESPONSIVENESS

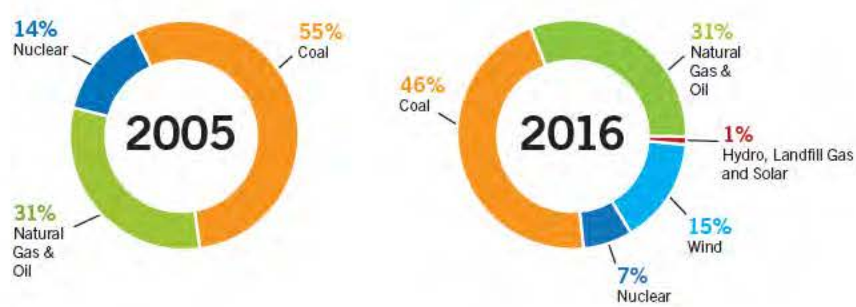
REDUCED AIR EMISSIONS

○ SO_2 ○ NO_x



GENERATION CAPACITY

2005-2016



DEDICATED / Providing safe and top tier customer service and reliability begins with our employees. Our people first culture allows us to draw upon the expertise, practices and experience of our employees to create a more diverse workforce better positioned to adapt to the future needs of our business.

Finally, we continue our strategy of investing outside of our regulated utilities in energy solutions that are complementary to our business. Through GXP Investments, our wholly owned subsidiary, we have sought out and invested in entrepreneurial and emerging growth companies that are working to develop technologies and build businesses vital to our country's energy future. We plan to allocate $20 million annually for five years to this initiative, and already see new opportunities that drive innovation in our business and those of our customers. Although we're still early in the investment cycle, we expect this initiative will provide us strategic value, enhanced energy products and services offerings for our customers, and generate solid financial returns for our shareholders.

ENVIRONMENTAL SUSTAINABILITY AND COMMUITY SUPPORT

An important part of our culture at Great Plains Energy is our commitment to our communities and the environment. Our customers depend on us to be good stewards of our environment and we see this as an opportunity to be part of a solution to environmental issues, both local and global.

Part of this ongoing commitment includes a transition from primarily fossil fuel-based generation to more sustainable renewable and carbon-free generation. Ten years ago, we had our 47 percent ownership in Wolf Creek, a non-carbon emitting generation source, but no renewable investments.

Today, Great Plains Energy has nearly 1,150 megawatts of wind, hydroelectric, and solar capacity and a selection of energy efficiency programs for our customers allowing us to reduce our carbon footprint. Following the merger with Westar, we will have one of the largest wind portfolios in the U.S. and we expect to meet nearly 50 percent of our retail customers' energy needs through non-carbon emitting resources and a balanced, greener, cleaner generation portfolio.

Finally, as we have for decades, Great Plains Energy continues to be one of the cornerstones of the communities we serve. Not only do we provide an essential service, but we strive to be an essential part of the fabric of our communities through

2012-2015

In Missouri, we expanded
ENERGY EFFICIENCY PROGRAMS

Began offering
SOLAR REBATES

Supporting the Clean Air Act,
WE COMPLETED MAJOR PLANT UPGRADES

#9 By end of 2015, we ranked #9 for U.S. Investor-owned utilities with wind capacity (AWEA U.S. Wind Industry Annual Market Report)

2016

CO_2 Ceased burning coal in two older units, reducing carbon dioxide emissions by 18%

Finished deploying more than
1,000 ELECTRIC VEHICLE CHARGING STATIONS

500MW Announced 20-year agreement totaling 500 MW of wind capacity in Missouri

2017 AND BEYOND

Reduce annual carbon dioxide output by
MILLIONS OF TONS

ENERGY-SAVING PROGRAMS
will be expanded to Kansas (pending approval)

KS

With recent wind contracts, we will have about
1,450 MW OF RENEWABLE GENERATION CAPACITY

DIVERSIFIED

We are working to build a more diverse, sustainable fleet by adopting clean power and energy efficiency practices. From electric vehicles to solar and wind energy, we are committed to clean, affordable and reliable energy. In 2016, we completed our first owned solar array. The Greenwood Energy Center's solar panels can produce about 4,700 megawatt-hours annually, enough to serve 440 homes.

DIVIDEND GROWTH CHART

2011–2016 based on fourth quarter declared dividend

targeted donations and investments, as well as employee volunteerism and leadership to organizations across our footprint each year.

We also consider ourselves a catalyst for economic development within our communities by providing competitively priced power, programs, and initiatives that are essential to businesses relocating to or expanding within the region. A healthy business environment is essential for job retention and creation, so we team with local and regional partners to offer tools that help strengthen and expand our communities.

BRIGHT - OUR ENERGY FUTURE

By executing upon our proven strategy of best-in-class operations, enhanced customer engagement and growth through targeted investments, Great Plains Energy is preparing for the region's bright energy future. With strategic investments, we expect to enhance our earnings power and provide further efficiencies and cost savings for customers. Through innovative thought leadership, we are focused on the opportunities before us. Working together as a team, we expect to enhance our total performance and deliver consistent long-term shareholder returns.

TERRY BASSHAM

Chairman of the Board, President and Chief Executive Officer

> **“TODAY, GREAT PLAINS ENERGY HAS NEARLY 1,150 MEGAWATTS OF WIND, HYDROELECTRIC, AND SOLAR CAPACITY AND A SELECTION OF ENERGY EFFICIENCY PROGRAMS FOR OUR CUSTOMERS ALLOWING US TO REDUCE OUR CARBON FOOTPRINT.”**

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, 2016**

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	Exact name of registrant as specified in its charter, state of incorporation, address of principal executive offices and telephone number	I.R.S. Employer Identification Number
001-32206	**GREAT PLAINS ENERGY INCORPORATED** (A Missouri Corporation) 1200 Main Street Kansas City, Missouri 64105 (816) 556-2200	43-1916803
000-51873	**KANSAS CITY POWER & LIGHT COMPANY** (A Missouri Corporation) 1200 Main Street Kansas City, Missouri 64105 (816) 556-2200	44-0308720

Each of the following classes or series of securities registered pursuant to Section 12(b) of the Act is registered on the New York Stock Exchange:

Registrant	Title of each class
Great Plains Energy Incorporated	Common Stock, without par value
	Depositary Shares Each Representing a 1/20th Interest in a Share of 7.00% Series B Mandatory Convertible Preferred Stock

Securities registered pursuant to Section 12(g) of the Act: Kansas City Power & Light Company Common Stock without par value.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Great Plains Energy Incorporated	Yes	X	No	_	Kansas City Power & Light Company	Yes	_	No	X

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Great Plains Energy Incorporated	Yes	_	No	X	Kansas City Power & Light Company	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.

Great Plains Energy Incorporated	Yes	X	No	_	Kansas City Power & Light Company	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 (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Great Plains Energy Incorporated	Yes	X	No	_	Kansas City Power & Light Company	Yes	X	No	_

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to the Form 10-K.

Great Plains Energy Incorporated	X	Kansas City Power & Light Company	X

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.

Great Plains Energy Incorporated	Large accelerated filer	X	Accelerated filer	_
	Non-accelerated filer	_	Smaller reporting company	_
Kansas City Power & Light Company	Large accelerated filer	_	Accelerated filer	_
	Non-accelerated filer	X	Smaller reporting company	_

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Great Plains Energy Incorporated	Yes	_	No	X	Kansas City Power & Light Company	Yes	_	No	X

The aggregate market value of the voting and non-voting common equity held by non-affiliates of Great Plains Energy Incorporated (based on the closing price of its common stock on the New York Stock Exchange on June 30, 2016) was approximately $4,700,571,576. All of the common equity of Kansas City Power & Light Company is held by Great Plains Energy Incorporated, an affiliate of Kansas City Power & Light Company.

On February 21, 2017, Great Plains Energy Incorporated had 215,384,601 shares of common stock outstanding.

On February 21, 2017, Kansas City Power & Light Company had one share of common stock outstanding and held by Great Plains Energy Incorporated.

Kansas City Power & Light Company meets the conditions set forth in General Instruction (I)(1)(a) and (b) of Form 10-K and is therefore filing this Form 10-K with the reduced disclosure format.

Documents Incorporated by Reference

Portions of the 2017 annual meeting proxy statement of Great Plains Energy Incorporated to be filed with the Securities and Exchange Commission are incorporated by reference in Part III of this report.

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This combined annual report on Form 10-K is being filed by Great Plains Energy Incorporated (Great Plains Energy) and Kansas City Power & Light Company (KCP&L). KCP&L is a wholly owned subsidiary of Great Plains Energy and represents a significant portion of its assets, liabilities, revenues, expenses and operations. Thus, all information contained in this report relates to, and where required is filed by, Great Plains Energy. Information that is specifically identified in this report as relating solely to Great Plains Energy, such as its financial statements and all information relating to Great Plains Energy's other operations, businesses and subsidiaries, including KCP&L Greater Missouri Operations Company (GMO), does not relate to, and is not filed by, KCP&L. KCP&L makes no representation as to that information. Neither Great Plains Energy nor its other subsidiaries have any obligation in respect of KCP&L's debt securities and holders of such securities should not consider Great Plains Energy's or its other subsidiaries' financial resources or results of operations in making a decision with respect to KCP&L's debt securities. Similarly, KCP&L has no obligation in respect of securities of Great Plains Energy or its other subsidiaries.

CAUTIONARY STATEMENTS REGARDING CERTAIN FORWARD-LOOKING INFORMATION

Statements made in this report that are not based on historical facts are forward-looking, may involve risks and uncertainties, and are intended to be as of the date when made. Forward-looking statements include, but are not limited to, statements relating to Great Plains Energy's proposed acquisition of Westar Energy, Inc. (Westar), the outcome of regulatory proceedings, cost estimates of capital projects and other matters affecting future operations. In connection with the safe harbor provisions of the Private Securities Litigation Reform Act of 1995, Great Plains Energy and KCP&L are providing a number of important factors that could cause actual results to differ materially from the provided forward-looking information. These important factors include: future economic conditions in regional, national and international markets and their effects on sales, prices and costs; prices and availability of electricity in regional and national wholesale markets; market perception of the energy industry, Great Plains Energy and KCP&L; changes in business strategy, operations or development plans; the outcome of contract negotiations for goods and services; effects of current or proposed state and federal legislative and regulatory actions or developments, including, but not limited to, deregulation, re-regulation and restructuring of the electric utility industry; decisions of regulators regarding rates the Companies can charge for electricity; adverse changes in applicable laws, regulations, rules, principles or practices governing tax, accounting and environmental matters including, but not limited to, air and water quality; financial market conditions and performance including, but not limited to, changes in interest rates and credit spreads and in availability and cost of capital and the effects on derivatives and hedges, nuclear decommissioning trust and pension plan assets and costs; impairments of long-lived assets or goodwill; credit ratings; inflation rates; effectiveness of risk management policies and procedures and the ability of counterparties to satisfy their contractual commitments; impact of terrorist acts, including, but not limited to, cyber terrorism; ability to carry out marketing and sales plans; weather conditions including, but not limited to, weather-related damage and their effects on sales, prices and costs; cost, availability, quality and deliverability of fuel; the inherent uncertainties in estimating the effects of weather, economic conditions and other factors on customer consumption and financial results; ability to achieve generation goals and the occurrence and duration of planned and unplanned generation outages; delays in the anticipated in-service dates and cost increases of generation, transmission, distribution or other projects; Great Plains Energy's ability to successfully manage its transmission joint ventures or to integrate or restructure the transmission joint ventures of Westar; the inherent risks associated with the ownership and operation of a nuclear facility including, but not limited to, environmental, health, safety, regulatory and financial risks; workforce risks, including, but not limited to, increased costs of retirement, health care and other benefits; the ability of Great Plains Energy to obtain the regulatory approvals necessary to complete the anticipated acquisition of Westar and the terms of those approvals; the risk that a condition to the closing of the anticipated acquisition of Westar or the committed debt or equity financing may not be satisfied or that the anticipated acquisition may fail to close; the failure to obtain, or to obtain on favorable terms, any financings necessary to complete or permanently finance the anticipated acquisition of Westar and the costs of such financing; the outcome of any legal proceedings, regulatory proceedings or enforcement matters that may be instituted relating to the anticipated acquisition of Westar; the costs incurred to consummate the anticipated acquisition of Westar; the possibility that the expected value creation from the anticipated acquisition of Westar will not be realized, or will not be realized within the expected time period; the credit ratings of Great Plains Energy following the anticipated acquisition of Westar; disruption from the anticipated acquisition of Westar making it more difficult to maintain relationships with customers, employees, regulators or suppliers and the diversion of management time and attention on the proposed transactions; and other risks and uncertainties.

This list of factors is not all-inclusive because it is not possible to predict all factors. Part I Item 1A Risk Factors included in this report should be carefully read for further understanding of potential risks for each of Great Plains Energy and KCP&L. Other sections of this report and other periodic reports filed by each of Great Plains Energy and KCP&L with the Securities and Exchange Commission (SEC) should also be read for more information regarding risk factors. Each forward-looking statement speaks only as of the date of the particular statement. Great Plains Energy and KCP&L undertake no obligation to publicly update or revise any forward-looking statement, whether as a result of new information, future events or otherwise.

GLOSSARY OF TERMS

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

Abbreviation or Acronym	Definition
AEPTHC	AEP Transmission Holding Company, LLC, a wholly owned subsidiary of American Electric Power Company, Inc.
AFUDC	Allowance for Funds Used During Construction
ARO	Asset Retirement Obligation
ASU	Accounting Standards Update
CCRs	Coal combustion residuals
Clean Air Act	Clean Air Act Amendments of 1990
CO_2	Carbon dioxide
Company	Great Plains Energy Incorporated and its consolidated subsidiaries
Companies	Great Plains Energy Incorporated and its consolidated subsidiaries and KCP&L and its consolidated subsidiaries
DOE	Department of Energy
EBITDA	Earnings before interest, income taxes, depreciation and amortization
ECA	Energy Cost Adjustment
EIRR	Environmental Improvement Revenue Refunding
EPA	Environmental Protection Agency
EPS	Earnings per common share
ERISA	Employee Retirement Income Security Act of 1974, as amended
FASB	Financial Accounting Standards Board
FERC	The Federal Energy Regulatory Commission
FCC	The Federal Communications Commission
FTC	Federal Trade Commission
GAAP	Generally Accepted Accounting Principles
GMO	KCP&L Greater Missouri Operations Company, a wholly owned subsidiary of Great Plains Energy
GPETHC	GPE Transmission Holding Company LLC, a wholly owned subsidiary of Great Plains Energy
Great Plains Energy	Great Plains Energy Incorporated and its consolidated subsidiaries
Great Plains Energy Board	Great Plains Energy Board of Directors
HSR	Hart-Scott-Rodino
KCC	The State Corporation Commission of the State of Kansas
KCP&L	Kansas City Power & Light Company, a wholly owned subsidiary of Great Plains Energy, and its consolidated subsidiaries
KCP&L Receivables Company	Kansas City Power & Light Receivables Company, a wholly owned subsidiary of KCP&L
kWh	Kilowatt hour
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations
MDNR	Missouri Department of Natural Resources
MECG	Midwest Energy Consumers Group
MEEIA	Missouri Energy Efficiency Investment Act

Abbreviation or Acronym	**Definition**
Merger Agreement	Agreement and Plan of Merger dated as of May 29, 2016, by and among Great Plains Energy, Westar and Merger Sub
Merger Sub	GP Star, Inc., a Kansas corporation that will be merged with and into Westar, pursuant to the Merger Agreement
MGP	Manufactured gas plant
MPS Merchant	MPS Merchant Services, Inc., a wholly owned subsidiary of GMO
MPSC	Public Service Commission of the State of Missouri
MW	Megawatt
MWh	Megawatt hour
NAV	Net Asset Value
NERC	North American Electric Reliability Corporation
NEIL	Nuclear Electric Insurance Limited
NOL	Net operating loss
NO_x	Nitrogen oxide
NPNS	Normal purchases and normal sales
NRC	Nuclear Regulatory Commission
OCI	Other Comprehensive Income
OMERS	OCM Credit Portfolio LP
PRB	Powder River Basin
QCA	Quarterly Cost Adjustment
RCRA	Resource Conservation and Recovery Act
RESRAM	Renewable Energy Standard Rate Adjustment Mechanism
RTO	Regional Transmission Organization
SEC	Securities and Exchange Commission
SERP	Supplemental Executive Retirement Plan
SO_2	Sulfur dioxide
SPP	Southwest Power Pool, Inc.
TCR	Transmission Congestion Right
TDC	Transmission Delivery Charge
Transource	Transource Energy, LLC and its subsidiaries, 13.5% owned by GPETHC
WCNOC	Wolf Creek Nuclear Operating Corporation
Westar	Westar Energy, Inc.
Westar Board	Westar Board of Directors
Wolf Creek	Wolf Creek Generating Station

PART I

ITEM 1. BUSINESS

General

Great Plains Energy Incorporated and Kansas City Power & Light Company are separate registrants filing this combined annual report on Form 10-K. The terms "Great Plains Energy," "Company," "KCP&L" and "Companies" are used throughout this report. "Great Plains Energy" and the "Company" refer to Great Plains Energy Incorporated and its consolidated subsidiaries, unless otherwise indicated. "KCP&L" refers to Kansas City Power & Light Company and its consolidated subsidiaries. "Companies" refers to Great Plains Energy Incorporated and its consolidated subsidiaries and KCP&L and its consolidated subsidiaries.

Information in other Items of this report as to which reference is made in this Item 1 is hereby incorporated by reference in this Item 1. The use of terms such as "see" or "refer to" shall be deemed to incorporate into this Item 1 the information to which such reference is made.

GREAT PLAINS ENERGY INCORPORATED

Great Plains Energy, a Missouri corporation incorporated in 2001 and headquartered in Kansas City, Missouri, is a public utility holding company and does not own or operate any significant assets other than the stock of its subsidiaries and cash and cash equivalents and a time deposit to be used to fund a portion of the cash consideration for the anticipated acquisition of Westar Energy, Inc. (Westar). Great Plains Energy's wholly owned direct subsidiaries with significant operations are as follows:

- KCP&L is an integrated, regulated electric utility that provides electricity to customers primarily in the states of Missouri and Kansas. KCP&L has one active wholly owned subsidiary, Kansas City Power & Light Receivables Company (KCP&L Receivables Company).
- GMO is an integrated, regulated electric utility that provides electricity to customers in the state of Missouri. GMO also provides regulated steam service to certain customers in the St. Joseph, Missouri area. GMO has two active wholly owned subsidiaries, GMO Receivables Company and MPS Merchant Services, Inc. (MPS Merchant). MPS Merchant has certain long-term natural gas contracts remaining from its former non-regulated trading operations.

Great Plains Energy also wholly owns GPE Transmission Holding Company, LLC (GPETHC). GPETHC owns 13.5% of Transource Energy, LLC (Transource) with the remaining 86.5% owned by AEP Transmission Holding Company, LLC (AEPTHC), a subsidiary of American Electric Power Company, Inc. GPETHC accounts for its investment in Transource under the equity method. Transource is focused on the development of competitive electric transmission projects.

On May 29, 2016, Great Plains Energy entered into an Agreement and Plan of Merger (Merger Agreement) by and among Great Plains Energy, Westar, and, from and after its accession to the Merger Agreement, GP Star, Inc., a wholly owned subsidiary of Great Plains Energy in the State of Kansas (Merger Sub). Pursuant to the Merger Agreement, subject to the satisfaction or waiver of certain conditions, Merger Sub will merge with and into Westar, with Westar continuing as the surviving corporation. Upon closing, pursuant to the Merger Agreement, Great Plains Energy will acquire Westar for (i) $51.00 in cash and (ii) a number, rounded to the nearest 1/10,000 of a share, of shares of Great Plains Energy common stock, equal to an exchange ratio that may vary between 0.2709 and 0.3148, based upon the volume-weighted average price per share of Great Plains Energy common stock during a 20 consecutive full trading day period ending on (and including) the third trading day immediately prior to the closing date of the merger, for each share of Westar common stock issued and outstanding immediately prior to the effective time of the merger, with Westar becoming a wholly owned subsidiary of Great Plains Energy. See Note 2 to the consolidated financial statements for additional information concerning the anticipated acquisition of Westar.

Great Plains Energy's sole reportable business segment is electric utility. For information regarding the revenues, income and assets attributable to the electric utility business segment, see Note 23 to the consolidated financial statements. Comparative financial information and discussion regarding the electric utility business segment can be found in Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A).

The electric utility segment consists of KCP&L, a regulated utility, GMO's regulated utility operations and GMO Receivables Company. Electric utility serves approximately 855,700 customers located in western Missouri and eastern Kansas. Customers include approximately 753,500 residences, 99,700 commercial firms and 2,500 industrials, municipalities and other electric utilities. Electric utility's retail revenues averaged approximately 91% of its total operating revenues over the last three years. Wholesale firm power, bulk power sales and miscellaneous electric revenues accounted for the remainder of electric utility's revenues. Electric utility is significantly impacted by seasonality with approximately one-third of its retail revenues recorded in the third quarter. Electric utility's total electric revenues were 100% of Great Plains Energy's revenues over the last three years. Electric utility's net income accounted for approximately 101%, 105% and 100% of Great Plains Energy's net income in 2016, 2015 and 2014, respectively.

Regulation
KCP&L and GMO are regulated by the Public Service Commission of the State of Missouri (MPSC) and KCP&L is also regulated by The State Corporation Commission of the State of Kansas (KCC) with respect to retail rates, certain accounting matters, standards of service and, in certain cases, the issuance of securities, certification of facilities and service territories. KCP&L and GMO are also subject to regulation by The Federal Energy Regulatory Commission (FERC) with respect to transmission, wholesale sales and rates, and other matters. KCP&L has a 47% ownership interest in Wolf Creek Generating Station (Wolf Creek), which is subject to regulation by the Nuclear Regulatory Commission (NRC) with respect to licensing, operations and safety-related requirements.

The table below summarizes the rate orders in effect for KCP&L's and GMO's retail rate jurisdictions.

	Regulator	Allowed Return on Equity	Rate-Making Equity Ratio	Rate Base (in billions)	Effective Date
KCP&L Missouri	MPSC	9.5%	50.09%	$2.6	September 2015
KCP&L Kansas	KCC	9.3%	50.48%	$2.1	October 2015
GMO	MPSC	9.5% - 9.75%[a]	(a)	(a)	February 2017

[a] GMO's current rate order reflects a global settlement with an implied return on equity range of 9.5% - 9.75% and does not contain an agreed upon rate-making equity ratio or rate base.

Missouri and Kansas jurisdictional retail revenues averaged approximately 70% and 30%, respectively, of electric utility's total retail revenues over the last three years.

See Item 7 MD&A, Critical Accounting Policies section, and Note 6 to the consolidated financial statements for additional information concerning regulatory matters.

Competition
Missouri and Kansas continue on the fully integrated retail utility model. As a result, electric utility does not compete with others to supply and deliver electricity in its franchised service territory, although other sources of energy can provide alternatives to retail electric utility customers. If Missouri or Kansas were to pass and implement legislation authorizing or mandating retail choice, electric utility may no longer be able to apply regulated utility accounting principles to deregulated portions of its operations and may be required to write off certain regulatory assets and liabilities.

Electric utility competes in the wholesale market to sell power in circumstances when the power it generates is not required for customers in its service territory. This competition primarily occurs within the SPP Integrated Marketplace, in which KCP&L and GMO are participants. Similar to other Regional Transmission Organization (RTO) or Independent System Operator (ISO) markets currently operating, this marketplace determines which generating units among market participants should run, within the operating constraints of a unit, at any given time for maximum cost-effectiveness.

In this regard, electric utility competes with owners of other generating stations and other power suppliers, principally other utilities within the Southwest Power Pool, Inc. (SPP) Integrated Marketplace, on the basis of availability and price. Electric utility's wholesale revenues averaged approximately 7% of its total revenues over the last three years.

Power Supply

Electric utility has approximately 6,500 MWs of owned generating capacity and also purchases power to meet its customers' needs, to satisfy firm power commitments or to meet renewable energy standards. Electric utility's purchased power from others, as a percentage of MWh requirements, averaged approximately 24% over the last three years. Management believes electric utility will be able to obtain enough power to meet its future demands due to the coordination of planning and operations in the SPP region and existing power purchase agreements; however, price and availability of power purchases may be impacted during periods of high demand.

Electric utility's total capacity by fuel type, including both owned generating capacity and power purchase agreements, is detailed in the table below.

Fuel Type	Estimated 2017 MW Capacity	Percent of Total Capacity
Coal	3,474	46 %
Nuclear	549	7
Natural gas and oil	2,352	31
Wind [(a)]	1,089	15
Solar and hydroelectric [(b)]	65	1
Total capacity	7,529	100 %

[(a)] MWs are based on nameplate capacity of the wind facility. Includes owned generating capacity of 149 MWs and long-term power purchase agreements of approximately 940 MWs of wind generation which expire in 2032 through 2037. Power purchase agreements for approximately 300 MWs of wind generation to begin in late 2017 and expire in 2037 are not included in the table above.

[(b)] Includes a long-term power purchase agreement for approximately 60 MWs of hydroelectric generation which expires in 2023.

Electric utility's projected peak summer demand for 2017 is approximately 5,800 MWs. Electric utility expects to meet its projected capacity requirements for the foreseeable future with its generation assets and power and capacity purchases.

KCP&L and GMO are members of the SPP. The SPP is an RTO mandated by FERC to ensure reliable supply of power, adequate transmission infrastructure and competitive wholesale prices of electricity. As members of the SPP, KCP&L and GMO are required to maintain a capacity margin of at least 12%. This net positive supply of capacity and energy is maintained through their generation assets, capacity agreements, power purchase agreements and peak demand reduction programs. The capacity margin is designed to ensure the reliability of electric energy in the SPP region in the event of operational failure of power generating units utilized by the members of the SPP.

Fuel

The principal fuel sources for electric utility's owned generation are coal and nuclear fuel. It is expected, with normal weather, that approximately 97% of 2017 owned generation will come from these sources with the remainder provided by wind, natural gas and oil. The actual 2016 and estimated 2017 fuel mix and delivered cost in cents per net kilowatt hour (kWh) generated are outlined in the following table.

	Fuel Mix [(a)]		Fuel cost in cents per net kWh generated	
Fuel	**Estimated 2017**	**Actual 2016**	**Estimated 2017**	**Actual 2016**
Coal	76 %	79 %	1.79	1.84
Nuclear	21	17	0.64	0.69
Natural gas and oil	<1	2	7.30	13.65
Wind	3	2	—	—
Total owned generation	100 %	100 %	1.45	1.46

(a) Fuel mix based on percent of net MWhs generated.

Coal

During 2017, electric utility's generating units, including jointly owned units, are projected to burn approximately 12 million tons of coal. KCP&L and GMO have entered into coal-purchase contracts with various suppliers in Wyoming's Powder River Basin (PRB), the nation's principal supply region of low-sulfur coal, and with local suppliers. The coal to be provided under these contracts is expected to satisfy approximately 100% of the projected coal requirements for 2017 and approximately 48% for 2018. The remainder of the coal requirements is expected to be fulfilled through additional contracts or spot market purchases. KCP&L and GMO have entered into coal contracts over time at higher average prices affecting coal costs for 2017 and beyond.

KCP&L and GMO have also entered into rail transportation contracts with various railroads to transport coal from the PRB to their generating units. The transportation services to be provided under these contracts are expected to satisfy almost all of the projected transportation requirements for 2017 and approximately 39% for 2018. The contract rates adjust for changes in railroad costs.

Nuclear Fuel

KCP&L owns 47% of Wolf Creek Nuclear Operating Corporation (WCNOC), the operating company for Wolf Creek, which is electric utility's only nuclear generating unit. Wolf Creek purchases uranium and has it processed for use as fuel in its reactor. This process involves conversion of uranium concentrates to uranium hexafluoride, enrichment of uranium hexafluoride and fabrication of nuclear fuel assemblies. The owners of Wolf Creek have on hand or under contract all of the uranium and conversion services needed to operate Wolf Creek through March 2027. The owners also have under contract 97% of the uranium enrichment and all of the fabrication required to operate Wolf Creek through March 2027 and September 2025, respectively.

See Note 5 to the consolidated financial statements for additional information regarding nuclear plant.

Environmental Matters

See Note 15 to the consolidated financial statements for information regarding environmental matters.

KANSAS CITY POWER & LIGHT COMPANY

KCP&L, a Missouri corporation incorporated in 1922 and headquartered in Kansas City, Missouri, is an integrated, regulated electric utility that engages in the generation, transmission, distribution and sale of electricity. KCP&L serves approximately 534,400 customers located in western Missouri and eastern Kansas. Customers include approximately 471,900 residences, 60,500 commercial firms, and 2,000 industrials, municipalities and other electric utilities. KCP&L's retail revenues averaged approximately 90% of its total operating revenues over the last three years. Wholesale firm power, bulk power sales and miscellaneous electric revenues accounted for the remainder of KCP&L's revenues. KCP&L is significantly impacted by seasonality with approximately one-third of its retail revenues recorded in the third quarter. Missouri and Kansas jurisdictional retail revenues averaged approximately 56% and 44%, respectively, of total retail revenues over the last three years.

Great Plains Energy and KCP&L Employees

At December 31, 2016, Great Plains Energy and KCP&L had 2,865 employees, including 1,750 represented by three local unions of the International Brotherhood of Electrical Workers (IBEW). KCP&L has labor agreements with Local 1613, representing clerical employees (expires March 31, 2018), with Local 1464, representing transmission and distribution workers (expires January 31, 2018), and with Local 412, representing power plant workers (expires February 28, 2018).

Executive Officers

All of the individuals in the following table have been officers or employees in the responsible positions with the Company noted below for the past five years unless otherwise indicated in the footnotes. The executive officers were reappointed to the indicated positions by the respective boards of directors, effective January 1, 2017, to hold such positions until their resignation, removal or the appointment of their successors. There are no family relationships between any of the executive officers, nor any arrangement or understanding between any executive officer and any other person involved in officer selection. Each executive officer holds the same position with GMO as he or she does with KCP&L.

Name	Age	Current Position(s)	Year First Assumed an Officer Position
Terry Bassham [(a)]	56	Chairman of the Board, President and Chief Executive Officer - Great Plains Energy and KCP&L	2005
Scott H. Heidtbrink [(b)]	55	Executive Vice President and Chief Operating Officer - KCP&L	2008
Kevin E. Bryant [(c)]	41	Senior Vice President - Finance and Strategy and Chief Financial Officer - Great Plains Energy and KCP&L	2006
Steven P. Busser [(d)]	48	Vice President - Risk Management and Controller - Great Plains Energy and KCP&L	2014
Charles A. Caisley [(e)]	44	Vice President - Marketing and Public Affairs - Great Plains Energy and KCP&L	2011
Ellen E. Fairchild [(f)]	55	Vice President, Chief Compliance Officer and Corporate Secretary - Great Plains Energy and KCP&L	2010
Heather A. Humphrey [(g)]	46	Senior Vice President - Corporate Services and General Counsel - Great Plains Energy and KCP&L	2010
Darrin R. Ives [(h)]	47	Vice President - Regulatory Affairs - KCP&L	2013
Lori A. Wright [(i)]	54	Vice President - Corporate Planning, Investor Relations and Treasurer - Great Plains Energy and KCP&L	2002

(a) Mr. Bassham was appointed Chairman of the Board in May 2013 and has served as Chief Executive Officer of Great Plains Energy, KCP&L and GMO since 2012. He has served as President of each company since 2011. He previously served as President and Chief Operating Officer of Great Plains Energy, KCP&L and GMO (2011-2012) and as Executive Vice President - Utility Operations of KCP&L and GMO (2010-2011). He was Executive Vice President - Finance and Strategic Development and Chief Financial Officer of Great Plains Energy (2005-2010) and of KCP&L and GMO (2009-2010).

(b) Mr. Heidtbrink was appointed Executive Vice President and Chief Operating Officer of KCP&L and GMO in 2012. He previously served as Senior Vice President - Supply of KCP&L and GMO (2009-2012). He was Senior Vice President - Corporate Services of KCP&L and GMO (2008), and Vice President - Power Generation & Energy Resources (2006-2008) of GMO.

[c] Mr. Bryant was appointed Vice President - Finance and Strategy and Chief Financial Officer of Great Plains Energy, KCP&L and GMO in 2015. He previously served as Vice President - Strategic Planning of Great Plains Energy, KCP&L and GMO (2014). He served as Vice President - Investor Relations and Strategic Planning and Treasurer of Great Plains Energy, KCP&L and GMO (2013). He served as Vice President - Investor Relations and Treasurer of Great Plains Energy, KCP&L and GMO (2011-2013). He was Vice President - Strategy and Risk Management of KCP&L and GMO (2011) and Vice President - Energy Solutions (2006-2011) of KCP&L and GMO.

[d] Mr. Busser was appointed Vice President - Risk Management and Controller of Great Plains Energy, KCP&L and GMO in 2016. He previously served as Vice President - Business Planning and Controller of Great Plains Energy, KCP&L and GMO (2014-2016). He served as Vice President - Treasurer of El Paso Electric Company (2011-2014). Prior to that, he served as Vice President - Treasurer and Chief Risk Officer (2006-2011) and Vice President - Regulatory Affairs and Treasurer (2004-2006) of El Paso Electric Company.

[e] Mr. Caisley was appointed Vice President - Marketing and Public Affairs of Great Plains Energy, KCP&L and GMO in 2011. He was Senior Director of Public Affairs (2008-2011) and Director of Governmental Affairs of KCP&L (2007-2008).

[f] Ms. Fairchild was appointed Vice President, Chief Compliance Officer and Corporate Secretary of Great Plains Energy, KCP&L and GMO in 2010. She was Senior Director of Investor Relations and Assistant Secretary (2010) and Director of Investor Relations (2008-2010) of Great Plains Energy, KCP&L and GMO.

[g] Ms. Humphrey was appointed Senior Vice President - Corporate Services and General Counsel of Great Plains Energy, KCP&L and GMO in 2016. She previously served as General Counsel (2010-2016) and Senior Vice President - Human Resources of Great Plains Energy, KCP&L and GMO (2012-2016). She served as Vice President - Human Resources of Great Plains Energy, KCP&L and GMO (2010-2012). She was Senior Director of Human Resources and Interim General Counsel of Great Plains Energy, KCP&L and GMO (2010) and Managing Attorney of KCP&L (2007-2010).

[h] Mr. Ives was appointed Vice President - Regulatory Affairs of KCP&L and GMO in 2013. He previously served as Senior Director - Regulatory Affairs of KCP&L and GMO (2011-2013). He was Assistant Controller of Great Plains Energy, KCP&L and GMO (2008 - 2011).

[i] Ms. Wright was appointed Vice President - Corporate Planning, Investor Relations and Treasurer of Great Plains Energy, KCP&L and GMO in 2016. She previously served as Vice President - Investor Relations and Treasurer of Great Plains Energy, KCP&L and GMO (2014-2016). She served as Vice President - Business Planning and Controller of Great Plains Energy, KCP&L and GMO (2009-2014). She was Controller of Great Plains Energy and KCP&L (2002-2008) and GMO (2008).

Available Information

Great Plains Energy's website is www.greatplainsenergy.com and KCP&L's website is www.kcpl.com. Information contained on these websites is not incorporated herein. The Companies make available, free of charge, on or through their websites, their annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, as soon as reasonably practicable after the companies electronically file such material with, or furnish it to, the SEC. In addition, the Companies make available on or through their websites all other reports, notifications and certifications filed electronically with the SEC.

The public may read and copy any materials that the Companies file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. For information on the operation of the Public Reference Room, please call the SEC at 1-800-SEC-0330. The SEC also maintains an Internet site at http://www.sec.gov that contains reports, proxy statements and other information regarding the Companies.

Investors should note that the Companies announce material financial information in SEC filings, press releases and public conference calls. Based on guidance from the SEC, the Companies may use the Investor Relations section of Great Plains Energy's website (www.greatplainsenergy.com) to communicate with investors about Great Plains Energy and KCP&L. It is possible that the financial and other information posted there could be deemed to be material information. The information on Great Plains Energy's website is not part of this document.

ITEM 1A. RISK FACTORS

Actual results in future periods for Great Plains Energy and KCP&L could differ materially from historical results and the forward-looking statements contained in this report. The Companies' business is influenced by many factors that are difficult to predict, involve uncertainties that may materially affect actual results and are often beyond their control. Additional risks and uncertainties not presently known or that the Companies' management currently believes to be immaterial may also adversely affect the Companies. This information, as well as the other information included in this report and in the other documents filed with the SEC, should be carefully considered before making an investment in the securities of Great Plains Energy or KCP&L. Risk factors of KCP&L are also risk factors of Great Plains Energy.

Risks Relating to the Anticipated Acquisition of Westar:

The ability of Great Plains Energy and Westar to complete the merger is subject to various closing conditions, including the receipt of consents and approvals from governmental authorities, which may impose conditions that could adversely affect Great Plains Energy or cause the merger to be abandoned.
To complete the merger, each of Great Plains Energy and Westar must make certain filings with and obtain certain consents and approvals from various governmental and regulatory authorities.

Great Plains Energy and Westar have not yet obtained all of the regulatory consents and approvals required to complete the merger. Governmental or regulatory agencies could seek to block or challenge the merger or could impose restrictions they deem necessary or desirable in the public interest as a condition to approving the merger. Great Plains Energy and Westar will be unable to complete the merger until the necessary consents and approvals are received from FERC, the NRC, KCC, and the MPSC (collectively referred to as the required governmental approvals). The Merger Agreement may require Great Plains Energy and/or Westar to accept conditions from these regulators that could adversely impact the combined company. If the required governmental approvals are not received, or they are not received on terms that satisfy the conditions set forth in the Merger Agreement, then neither Great Plains Energy nor Westar will be obligated to complete the merger.

In addition, governmental authorities could seek to block or challenge the merger, including after closing, as they deem necessary or desirable in the public interest. In some jurisdictions, a private party could initiate an action under the antitrust laws challenging or seeking to enjoin the merger, before or after it is completed. Great Plains Energy or Westar may not prevail and may incur significant costs in defending or settling any action under the antitrust laws.

FERC Commissioner Norman Bay's resignation, effective February 3, 2017, left FERC with two sitting commissioners and the inability to convene a quorum. Without a quorum, FERC cannot issue certain orders on contested cases, including Great Plains Energy's and Westar's merger application. If a replacement commissioner is not appointed and confirmed in a timely fashion, the closing of the merger could be delayed until such time that a replacement commissioner is approved by the Senate.

The September 2016 special meetings at which the Great Plains Energy shareholders and the Westar shareholders approved the transactions contemplated by the Merger Agreement have taken place before all required approvals have been obtained and, in certain cases, before the terms of any conditions to obtain such required approvals are known. As a result, Great Plains Energy and Westar may make decisions after the special meetings to waive a condition or approve certain actions required to obtain necessary approvals without seeking further shareholder approval. Such actions could have an adverse effect on the combined company.

In addition, the Merger Agreement contains other customary conditions to the closing of the merger, each of which must be satisfied or waived in order to complete the merger.

If Great Plains Energy and Westar are unable to complete the merger, Great Plains Energy would be subject to a number of risks, including the following:

- Great Plains Energy would not realize the anticipated benefits of the merger, including, among other things, increased operating efficiencies and future cost savings;

- the attention of management of Great Plains Energy may have been diverted to the merger rather than to its own operations and the pursuit of other opportunities that could have been beneficial to the Company;

- the potential loss of key personnel during the pendency of the merger as employees may experience uncertainty about their future roles with the combined company; and

- the trading price of Great Plains Energy common stock may decline to the extent that the current market prices reflect a market assumption that the merger will be completed.

Great Plains Energy will be required to pay Westar a termination fee of $380 million if the Merger Agreement is terminated due to a failure to receive the required governmental approvals or a failure to receive them on terms and conditions that would not result in a material adverse effect on Great Plains Energy and its subsidiaries, after giving effect to the merger.

We can provide no assurance that the various closing conditions will be satisfied and that the required governmental approvals will be obtained, or that any required conditions will not materially adversely affect the combined company following the merger. In addition, we can provide no assurance that these conditions will not result in the abandonment or delay of the merger. The occurrence of any of these events individually or in combination could have a material adverse effect on Great Plains Energy's results of operations and the trading price of Great Plains Energy common stock.

The Merger Agreement contains provisions that limit Great Plains Energy's or Westar's ability to pursue alternatives to the merger, could discourage a potential competing acquirer of either Great Plains Energy or Westar from making a favorable alternative transaction proposal and, in certain circumstances, could require Westar or Great Plains Energy to pay a termination fee to the other party.

Under the Merger Agreement, Westar and Great Plains Energy each are restricted from entering into alternative merger or acquisition transactions. Unless and until the Merger Agreement is terminated, subject to specified exceptions, each party is restricted from soliciting, initiating or knowingly encouraging, inducing or facilitating, or participating in any discussions or negotiations with any person regarding, or cooperating in any way with any person with respect to, any alternative proposal or any inquiry or proposal that would reasonably be expected to lead to an alternative proposal. Under certain circumstances either Westar or Great Plains Energy may be required to pay a termination fee to the other if they were to enter into an alternative transaction within twelve months of a termination of the Merger Agreement. These provisions could discourage a third party that may have an interest in acquiring all or a significant part of Westar or Great Plains Energy from considering or proposing that acquisition, including under circumstances in which the Merger Agreement would be terminated on a separate basis, even if such third party were prepared to pay consideration with a higher per share cash or market value than the market value proposed to be received or realized in the merger. As a result of these restrictions, neither Westar nor Great Plains Energy may be able to enter into an agreement with respect to a more favorable alternative transaction without incurring potentially significant liability to the other.

Great Plains Energy and Westar will be subject to various uncertainties while the merger is pending that may cause disruption and may make it more difficult to maintain relationships with employees, suppliers, or customers.

Uncertainty about the effect of the merger on employees, suppliers and customers may have an adverse effect on Great Plains Energy and Westar. Although Great Plains Energy and Westar intend to take steps designed to reduce any adverse effects, these uncertainties may impair the ability of Great Plains Energy or Westar to attract, retain and motivate key personnel until the merger is completed and for a period of time thereafter, and could cause customers, suppliers and others that deal with Great Plains Energy or Westar to seek to change or terminate existing business relationships with Great Plains Energy or Westar or not enter into new relationships or transactions.

Employee retention and recruitment may be particularly challenging prior to the completion of the merger, as employees and prospective employees may experience uncertainty about their future roles with the combined company. If, despite Great Plains Energy's and Westar's retention and recruiting efforts, key employees depart or fail to continue employment with either company because of issues relating to the uncertainty and difficulty of integration or a desire not to remain with the combined company, Great Plains Energy's and/or Westar's financial results could be adversely affected. Furthermore, the combined company's operational and financial performance following the merger could be adversely affected if it is unable to retain key employees and skilled workers of Great Plains Energy and Westar. The loss of the services of key employees and skilled workers and their experience and knowledge regarding Great Plains Energy's and Westar's businesses could adversely affect the combined company's future operating results and the successful ongoing operation of its businesses.

Failure to successfully combine the businesses of Great Plains Energy and Westar in the expected time frame may adversely affect the future results of the combined company, and, consequently, the value of Great Plains Energy common stock.

The success of the merger will depend, in part, on the ability of Great Plains Energy to realize the anticipated benefits and efficiencies from combining the businesses of Great Plains Energy and Westar. To realize these anticipated benefits, the businesses must be successfully combined. If the combined company is not able to achieve these objectives, or is not able to achieve these objectives on a timely basis, the anticipated benefits of the transactions may not be realized fully or at all. In addition, the actual integration may result in additional and unforeseen expenses, which could reduce the anticipated benefits of the merger. These integration difficulties could result in a decline in the market value of Great Plains Energy common stock.

Failure to complete the merger, or significant delays in completing the merger, could negatively affect the trading prices of Great Plains Energy common stock and the future business and financial results of Great Plains Energy.

Completion of the merger is not assured and is subject to risks, including the risk that approval of the merger by governmental agencies is not obtained or that other closing conditions are not satisfied. If the merger is not completed, or if there are significant delays in completing the merger, it could negatively affect the trading price of Great Plains Energy common stock and the future business and financial results of Great Plains Energy. Great Plains Energy also will be subject to several risks, including the following:

- Great Plains Energy may be liable for damages to Westar under the terms and conditions of the Merger Agreement;

- negative reactions from the financial markets, including declines in the price of Great Plains Energy common stock due to the fact that current prices may reflect a market assumption that the merger will be completed;

- having to pay certain significant costs relating to the merger, including, in certain circumstances, a termination fee; and

- the attention of Great Plains Energy will have been diverted to the merger rather than Great Plains Energy's own operations and pursuit of other opportunities that could have been beneficial to Great Plains Energy.

Each of Great Plains Energy and Westar will incur significant transaction and merger-related costs in connection with the merger.

Great Plains Energy and Westar have incurred, and expect to continue to incur, costs associated with combining the operations of the two companies, as well as transaction fees and other costs related to the merger. Additional unanticipated costs may be incurred in the integration of the businesses of Great Plains Energy and Westar. Although Great Plains Energy and Westar expect that the elimination of duplicative costs, as well as the realization of other efficiencies related to the integration of the businesses, may offset incremental transaction, merger-related and restructuring costs over time, any net benefit may not be achieved in the near term, or at all.

Great Plains Energy may be unable to obtain the anticipated combination of financing or the necessary amount of financing to pay the cash portion of the merger consideration.
Great Plains Energy intends to finance the cash portion of the merger consideration with a combination of cash on hand and the proceeds from the issuance of a combination of common stock, mandatory convertible preferred stock and debt securities. In October 2016, Great Plains Energy completed registered public offerings of 60.5 million shares of common stock for total net proceeds of $1.55 billion and 17.3 million depositary shares each representing a 1/20th interest in a share of Great Plains Energy's 7.00% Series B Mandatory Convertible Preferred Stock (Series B Preferred Stock) for total net proceeds of $836.2 million.

To the extent the proceeds from Great Plains Energy's remaining expected securities issuances are not available on or before the closing date of the merger, or are in insufficient amounts, Great Plains Energy may use borrowings under its bridge term loan facility to fund the remaining portion of the cash consideration for the merger. However, the availability of funds under the bridge term loan facility is subject to certain conditions including, among others, the absence of a material adverse effect with respect to Westar and its subsidiaries, taken as a whole, the accuracy of certain representations and warranties and the absence of certain defaults with respect to indebtedness of Great Plains Energy and its subsidiaries.

If Great Plains Energy is required to obtain more debt financing than anticipated, whether through the issuance of debt securities or borrowings under the bridge term loan facility, the required regulatory approvals to complete the merger may be more difficult to obtain and the combined company's credit ratings and ability to service its debt could be adversely affected.

Current Great Plains Energy shareholders will have a reduced ownership and voting interest after the merger and will exercise less influence over management of the combined company.
Great Plains Energy has already issued approximately 60.5 million shares of common stock in order to raise proceeds to fund a portion of the cash consideration for the merger. Furthermore, Great Plains Energy issued in October 2016 and also expects to issue at the time of the merger, shares of mandatorily convertible preferred stock, which shall ultimately convert into common stock. In connection with the completion of the merger, Great Plains Energy will also issue up to approximately 45 million shares of Great Plains Energy common stock to Westar shareholders in connection with the transactions contemplated by the merger agreement.

Great Plains Energy shareholders currently have the right to vote for the Company's board of directors and on other matters affecting Great Plains Energy. When the merger occurs, each Westar shareholder that receives shares of Great Plains Energy common stock will become a shareholder of Great Plains Energy with a percentage ownership of the combined company that is significantly smaller than the shareholder's percentage ownership in Westar. Correspondingly, each Great Plains Energy shareholder will remain a shareholder of Great Plains Energy with a percentage ownership of the combined company that is smaller than the shareholder's percentage ownership of Great Plains Energy prior to the merger.

As a result of these securities issuances and reduced ownership percentages, current Great Plains Energy shareholders will have less influence on the management and policies of the combined company than they now have with respect to Great Plains Energy.

The market price of Great Plains Energy common stock after the merger may be affected by factors different from those affecting the shares of Great Plains Energy or Westar currently.
Upon completion of the merger, the businesses of the combined company will differ from those of Great Plains Energy and Westar prior to the merger in important respects and, accordingly, the results of operations of the combined company and the market price of Great Plains Energy's shares of common stock following the merger may be affected by factors different from those currently affecting the independent results of operations of Great Plains Energy and Westar.

There are risks associated with the mandatory convertible preferred stock Great Plains Energy expects to issue pursuant to its stock purchase agreement with OMERS to finance a portion of the merger consideration.
In connection with the Merger Agreement, Great Plains Energy entered into a stock purchase agreement with OCM Credit Portfolio LP (OMERS) pursuant to which Great Plains Energy will issue and sell to OMERS $750 million of 7.25% Mandatory Convertible Preferred Stock, Series A (Series A Preferred Stock) upon the consummation of the merger. Upon entering into the stock purchase agreement, Great Plains Energy paid OMERS $15 million, which is not refundable in the event the merger is not consummated. The terms of the Series A Preferred Stock will provide that if Great Plains Energy misses two quarterly dividend payments, Great Plains Energy would be required to appoint two representatives designated by OMERS to the Great Plains Energy Board. In addition, OMERS' non-U.S. based ownership could potentially complicate obtaining the required regulatory approvals for the merger.

The combined company's indebtedness following the merger will be greater than Great Plains Energy's existing indebtedness. As a result, it may be more difficult for the combined company to pay or refinance its debts or take other actions, and the combined company may need to divert its cash flow from operations to debt service payments.
In connection with the merger, Great Plains Energy will incur additional debt to pay the cash portion of the merger consideration and transaction expenses and the indebtedness of the combined company will include Westar's outstanding debt. The combined company's debt service obligations with respect to this increased indebtedness could have an adverse impact on its earnings and cash flows, which after the merger would include the earnings and cash flows of Westar, for as long as the indebtedness is outstanding.

The combined company's increased indebtedness could also have important consequences to holders of Great Plains Energy securities. For example, it could:

- make it more difficult for the combined company to pay or refinance its debts as they become due during adverse economic and industry conditions because any decrease in revenues could cause the combined company to not have sufficient cash flows from operations to make its scheduled debt payments;
- limit the combined company's flexibility to pursue other strategic opportunities or react to changes in its business and the industry in which it operates and, consequently, place the combined company at a competitive disadvantage to its competitors with less debt;
- require a substantial portion of the combined company's cash flows from operations to be used for debt service payments, thereby reducing the availability of its cash flow to fund working capital, capital expenditures, acquisitions, dividend payments and other general corporate purposes;
- result in a downgrade in the rating of the combined company's indebtedness, which could limit its ability to borrow additional funds or increase the interest rates applicable to its indebtedness (after the announcement of the merger, Moody's Investors Service placed its long-term ratings of Great Plains Energy on review for downgrade and Standard & Poor's Ratings Services revised the outlook of Great Plains Energy, KCP&L and GMO from stable to negative);
- result in higher interest expense in the event of increases in interest rates since some of Great Plains Energy's borrowings are, and will continue to be, at variable rates of interest; or
- require that additional terms, conditions or covenants be placed on Great Plains Energy.

Based upon current levels of operations, Great Plains Energy expects to be able to generate sufficient cash on a consolidated basis to make all of the principal and interest payments when such payments are due under Great Plains Energy's and its current subsidiaries' existing credit facilities, indentures and other instruments governing their outstanding indebtedness, and under the indebtedness of Westar and its subsidiaries that may remain outstanding after the merger; but there can be no assurance that the combined company will be able to repay or refinance such borrowings and obligations.

Great Plains Energy is committed to maintaining its credit ratings. In order to maintain these credit ratings, Great Plains Energy may consider it appropriate to reduce the amount of indebtedness outstanding following the merger. This may be accomplished in several ways, including issuing additional shares of common stock or securities convertible into shares of common stock, reducing discretionary uses of cash or a combination of these and other measures. Issuances of additional shares of common stock or securities convertible into shares of common stock would have the effect of diluting the ownership percentage that current Great Plains Energy shareholders and former Westar shareholders hold in the combined company and might reduce the reported earnings per share. Any potential issuances could be adversely impacted by movements in the overall equity markets or the utility sector of the market and ultimately impact any offering price. The specific measures that Great Plains Energy may ultimately decide to use to maintain or improve its credit ratings and their timing will depend upon a number of factors, including market conditions and forecasts at the time those decisions are made.

The combined company will record goodwill that could become impaired and adversely affect the combined company's operating results.

The merger will be accounted for as an acquisition by Great Plains Energy in accordance with Generally Accepted Accounting Principles (GAAP). Under the acquisition method of accounting, the assets and liabilities of Westar will be recorded, as of completion, at their respective fair values and added to those of Great Plains Energy. The reported financial condition and results of operations of Great Plains Energy issued after completion of the merger will reflect Westar balances and results after completion of the merger, but will not be restated retroactively to reflect the historical financial position or results of operations of Westar for periods prior to the merger.

Under the acquisition method of accounting, the total purchase price will be allocated to Westar's tangible assets and liabilities and identifiable intangible assets based on their fair values as of the date of completion of the merger. The fair value of Westar's tangible and intangible assets and liabilities subject to the rate setting practices of their regulators approximate their carrying values. The excess of the purchase price over those fair values will be recorded as goodwill. Great Plains Energy expects that the merger will result in the creation of goodwill based upon the application of the acquisition method of accounting. To the extent the value of goodwill or intangibles becomes impaired, the combined company may be required to incur material charges relating to such impairment. Such a potential impairment charge could have a material impact on the combined company's operating results.

The anticipated benefits of combining Great Plains Energy and Westar may not be realized.

Great Plains Energy and Westar entered into the Merger Agreement with the expectation that the merger would result in various benefits, including, among other things, increased operating efficiencies. Although Great Plains Energy and Westar expect to achieve the anticipated benefits of the merger, achieving them is subject to a number of uncertainties, including:

- whether United States federal and state public utility, antitrust and other regulatory authorities whose approval is required to complete the merger impose conditions on the merger, which may have an adverse effect on the combined company, including its ability to achieve the anticipated benefits of the merger;
- the ability of the two companies to combine certain of their operations or take advantage of expected growth opportunities;
- general market and economic conditions;
- general competitive factors in the marketplace; and
- higher than expected costs required to achieve the anticipated benefits of the merger.

No assurance can be given that these benefits will be achieved or, if achieved, the timing of their achievement. Failure to achieve these anticipated benefits could result in increased costs and decreases in the amount of expected revenues or net income of the combined company.

The merger may not be accretive to earnings and may cause dilution to Great Plains Energy's earnings per share, which may negatively affect the market price of Great Plains Energy common stock.
Great Plains Energy currently anticipates that the merger will be neutral to Great Plains Energy's forecasted earnings per share on a stand-alone basis in the first full calendar year after closing increasing to approximately a 10 percent accretion in the third full calendar year after closing. This expectation is based on preliminary estimates, which may materially change. Great Plains Energy may encounter additional transaction and integration-related costs, may fail to realize all of the benefits anticipated in the merger or be subject to other factors that affect preliminary estimates or its ability to realize operational efficiencies. Any of these factors could cause a decrease in Great Plains Energy's earnings per share or decrease or delay the expected accretive effect of the merger and contribute to a decrease in the price of Great Plains Energy's common stock.

The merger will combine two companies that are currently affected by developments in the electric utility industry, including changes in regulation and increased competition. A failure to adapt to the changing regulatory environment after the merger could adversely affect the stability of the combined company's earnings and could result in the erosion of its market positions, revenues and profits.
Because Great Plains Energy, Westar and their respective subsidiaries are regulated in the U.S. at the federal level and in several states, the two companies have been and will continue to be affected by legislative and regulatory developments. After the merger, the combined company and/or its subsidiaries will be subject in the U.S. to extensive federal regulation as well as to state regulation in Missouri and Kansas. Each of these jurisdictions has implemented, is in the process of implementing or possibly will implement changes to the regulatory and legislative framework applicable to the electric utility industry. These changes could have a material adverse effect on the combined company.

The costs and burdens associated with complying with these regulatory jurisdictions may have a material adverse effect on the combined company. Moreover, potential legislative changes, regulatory changes or otherwise may create greater risks to the stability of utility earnings generally. If the combined company is not responsive to these changes, it could suffer erosion in market position, revenues and profits as competitors gain access to the service territories of its utility subsidiaries.

The market value of Great Plains Energy common stock could decline if large amounts of its common stock are sold in anticipation of or following the merger.
Following the merger, shareholders of Great Plains Energy and former shareholders of Westar will own interests in a combined company operating an expanded business with more assets and a different mix of liabilities. Current shareholders of Great Plains Energy and Westar may not wish to continue to invest in the combined company, or may wish to reduce their investment in the combined company, in order to comply with institutional investing guidelines, to increase diversification or to track any rebalancing of stock indices in which Great Plains Energy or Westar common stock is or was included. If, before or following the merger, large amounts of Great Plains Energy common stock are sold, the price of its common stock could decline.

Utility Regulatory Risks:

Complex utility regulation could adversely affect the Companies' results of operations, financial position and cash flows.
The Companies are subject to, or affected by, extensive federal and state utility regulation, including regulation by the MPSC, KCC, FERC, NRC, North American Electric Reliability Corporation (NERC) and SPP. The Companies must address in their business planning and management of operations the effects of existing and proposed laws and regulations and potential changes in the regulatory framework, including initiatives by federal and state legislatures, RTOs, utility regulators and taxing authorities. Failure of the Companies to obtain adequate rates or regulatory approvals in a timely manner, new or changed laws, regulations, standards, interpretations or other legal requirements, deterioration of the Companies' relationship with regulators and increased compliance costs and potential non-compliance consequences may materially affect the Companies' results of operations, financial position and cash flows. Additionally, regulators may impose burdensome restrictions and conditions on the

Companies' transactions and ventures, rendering them less attractive from a financial or operational perspective. Certain of these risks are addressed in greater detail below.

The outcome of retail rate proceedings could have a material impact on the business and is largely outside the Companies' control.

The rates that KCP&L and GMO are allowed to charge their customers significantly influence the Companies' results of operations, financial position and cash flows. These rates are subject to the determination, in large part, of governmental entities outside of the Companies' control, including the MPSC, KCC and FERC.

The utility rate-setting principle generally applicable to KCP&L and GMO is that rates should provide a reasonable opportunity to recover expenses and investments prudently incurred to provide utility service plus a reasonable return on such investments. Various expenses incurred by KCP&L and GMO have been excluded from rates by the MPSC and KCC in past rate cases as not being prudently incurred or not providing utility customer benefit, and there is a risk that certain expenses incurred in the future may not be recovered in rates. Third-parties often intervene in the utilities' rate cases and argue that certain costs have not been prudently incurred or are otherwise not recoverable in rates. The MPSC and KCC also have in the past and may in the future exclude from rates all or a portion of investments in various facilities as not being prudently incurred or not being useful in providing utility service.

As discussed in the "Environmental Risks" and "Financial Risks" sections below, the Companies' capital expenditures are expected to be substantial over the next several years and there is a risk that a portion of the capital costs could be excluded from rates in future rate cases.

The Companies are also exposed to cost-recovery shortfalls due to the inherent "regulatory lag" in the rate-setting process, especially during periods of significant cost inflation or declining retail usage, as KCP&L's and GMO's utility rates are generally based on historical information and are not subject to adjustment between rate cases, other than principally for fuel, purchased power, transmission and property taxes for KCP&L in Kansas; fuel, purchased power, certain transmission costs and demand-side investments for KCP&L in Missouri; and fuel, purchased power, certain transmission costs, demand-side investments and renewable energy (solar rebates) for GMO. These and other factors may result in under-recovery of costs, failure to earn the authorized return on investment, or both.

Failure to timely recover the full investment costs of capital projects, the impact of renewable energy and energy efficiency programs, other utility costs and expenses due to regulatory disallowances, regulatory lag or other factors could lead to lowered credit ratings, reduced access to capital markets, increased financing costs, lower flexibility due to constrained financial resources and increased collateral security requirements, or reductions or delays in planned capital expenditures. In response to competitive, economic, political, legislative, public perception (including, but not limited to, the Companies' environmental reputation) and regulatory pressures, the Companies may be subject to rate moratoriums, rate refunds, limits on rate increases, lower allowed returns on investments or rate reductions, including phase-in plans designed to spread the impact of rate increases over an extended period of time for the benefit of customers.

Regulatory requirements regarding utility operations may increase costs and may expose the Companies to compliance penalties or adverse rate consequences.

The FERC, NERC and SPP have implemented and enforce an extensive set of transmission system reliability, cybersecurity and critical infrastructure protection standards that apply to public utilities, including KCP&L and GMO. The MPSC and KCC have the authority to implement utility operational standards and requirements, such as vegetation management standards, facilities inspection requirements and quality of service standards. In addition, the Companies are also subject to health, safety and other requirements enacted by the Occupational Safety and Health Administration, the Department of Transportation, the Department of Labor and other federal and state agencies. As discussed more fully under "Operational Risks," the NRC extensively regulates nuclear power plants, including Wolf Creek. The costs of existing, new or modified regulations, standards and other requirements could have an adverse effect on the Companies' results of operations, financial position and cash flows as a result of increased operations or maintenance and capital expenditures for new facilities or to repair or improve existing facilities. In addition, failure to meet quality of service, reliability, cybersecurity, critical infrastructure protection, operational or other standards and requirements could expose the Companies to penalties, additional compliance costs, or adverse rate consequences.

Tax Reform Risk:

Changes in federal income tax policy could negatively impact the Companies.
The Companies are impacted by the U.S. federal income tax policy, including corporate income tax laws. Both the new federal administration and the Republicans in the House of Representatives have made public statements in support of comprehensive tax reform, including significant changes in the U.S. corporate income tax laws. These proposed changes include, among other things, a reduction in the corporate income tax rate, the immediate deductibility of 100% of capital expenditures, and the elimination of the interest expense deduction. The Companies are currently unable to predict whether these reform discussions will result in any significant changes to existing tax laws, or if any such changes would have a cumulative positive or negative impact on the Companies. However, it is possible that changes in the U.S. federal income tax laws could have a material adverse effect on the Companies' results of operations, financial position and cash flows.

Environmental Risks:

The Companies are subject to current and potential environmental requirements and the incurrence of environmental liabilities, any or all of which may adversely affect their business and financial results.
The Companies are subject to extensive federal, state and local environmental laws, regulations and permit requirements relating to air and water quality, waste management and disposal, natural resources and health and safety. In addition to imposing continuing compliance obligations and remediation costs for historical and pre-existing conditions, these laws, regulations and permits authorize the imposition of substantial penalties for noncompliance, including fines, injunctive relief and other sanctions. There is also a risk that new environmental laws and regulations, new administrative or judicial interpretations of environmental laws and regulations, or the requirements in new or renewed environmental permits could adversely affect the Companies' operations. In addition, there is also a risk of lawsuits brought by third parties alleging violations of environmental commitments or requirements, claiming creation of a public nuisance or other matters, and seeking injunctions or monetary damages or other damages. Certain federal courts have held that state and local governments and private parties have standing to bring climate change tort suits seeking company-specific emission reductions and damages.

Environmental permits are subject to periodic renewal, which may result in more stringent permit conditions and limits. New facilities, or modifications of existing facilities, may require new environmental permits or amendments to existing permits. Delays in the environmental permitting process, public opposition and challenges, denials of permit applications, limits or conditions imposed in permits and the associated uncertainty may materially adversely affect the cost and timing of projects, and thus materially adversely affect the Companies' results of operations, financial position and cash flows.

KCP&L and GMO periodically seek recovery of capital costs and expenses for environmental compliance and remediation through rate increases; however, there can be no assurance that recovery of these costs would be granted. KCP&L and GMO may be subject to material adverse rate treatment in response to competitive, economic, political, legislative or regulatory pressures and/or public perception of the Companies' environmental reputation. The costs of compliance or noncompliance with environmental requirements, remediation costs, adverse outcomes of lawsuits, or failure to timely recover environmental costs could have a material adverse effect on the Companies' results of operations, financial position and cash flows. Certain of these matters are discussed in more detail below. See Note 15 to the consolidated financial statements for additional information regarding certain significant environmental matters and Great Plains Energy's and KCP&L's current estimates of capital expenditures to comply with environmental regulations.

Air and Climate Change

The Companies' current generation capacity is primarily coal-fired, and is estimated to produce about one ton of carbon dioxide (CO_2) per MWh, or approximately 19 million tons and 15 million tons of CO_2 per year for Great Plains Energy and KCP&L, respectively. Management believes it is possible that additional federal or relevant state or local laws or regulations could be enacted to address global climate change. At the international level, in December 2015 the Paris Agreement was adopted by nearly 200 countries and became effective in November 2016 as the threshold of at least 55 countries representing at least 55% of global greenhouse gas emissions have joined it through ratification. The Paris Agreement does not result in any new, legally binding obligations on the United States to meet a particular greenhouse gas emissions target, but establishes a framework for international cooperation on climate change. Other international agreements legally binding on the United States may be reached in the future. Such new laws, regulations or treaties could mandate new or increased requirements to control or reduce the emission of greenhouse gases, such as CO_2, which are created in the combustion of fossil fuels. These requirements could include, among other things, taxes or fees on fossil fuels or emissions, cap and trade programs, emission limits and clean or renewable energy standards.

The Environmental Protection Agency (EPA) has enacted various regulations regarding the reporting and permitting of greenhouse gases and has proposed other regulations under the existing Clean Air Act. The EPA has established thresholds for greenhouse gas emissions, defining when Clean Air Act permits under the New Source Performance Standards, New Source Review and Title V operating permits programs would be required for new or existing industrial facilities and when the installation of best available control technology would be required. In August 2015, the EPA finalized its Clean Power Plan which sets CO_2 emission performance rates for existing affected fossil fuel-fired electric generating units. Specifically, the EPA translated those performance rates into a state goal measured in mass and rate based on each state's generation mix. The states have the ability to develop their own plans for affected units to achieve either the performance rates directly or the state goals, with guidelines for the development, submittal and implementation of those plans. In February 2016, the U.S. Supreme Court granted a stay of the Clean Power Plan putting the rule on hold pending review in the United States Court of Appeals for the District of Columbia Circuit and any subsequent review by the U.S. Supreme Court if such review is sought. Compliance with the Clean Power Plan has the potential of having significant financial and operational impacts on Great Plains Energy and KCP&L; however, the ultimate financial and operational consequences to Great Plains Energy and KCP&L cannot be determined until the outcome of pending litigation is known and/or the state plans to implement the Clean Power Plan are known. Additional federal and/or state legislation or regulation respecting greenhouse gas emissions may be proposed or enacted in the future. Requirements to reduce greenhouse gas emissions may cause the Companies to incur significant costs relating to their ongoing operations (such as for additional environmental control equipment, retiring and replacing existing generation, re-powering existing plants to utilize alternative fuel or selecting more costly generation alternatives), to procure emission allowance credits, or due to the imposition of taxes, fees or other governmental charges as a result of such emissions.

Water

The Clean Water Act and associated regulations enacted by the EPA form a comprehensive program to restore and preserve water quality. All of the Companies' generating facilities, and certain of their other facilities, are subject to the Clean Water Act.

In May 2014, the EPA finalized regulations regarding protection of aquatic life from being killed or injured by cooling water intake structures. KCP&L's generation facilities with cooling water intake structures are subject to the best technology available standards based on studies completed to comply with such standards. The rule provides flexibility to work with the states to develop the best technology available to minimize aquatic species impacted by being pinned against intake screens or drawn into cooling water systems.

KCP&L holds a permit from the Missouri Department of Natural Resources (MDNR) covering water discharge from its Hawthorn Station. The permit authorizes KCP&L to, among other things, withdraw water from the Missouri River for cooling purposes and return the heated water to the Missouri River. KCP&L has applied for a renewal of this permit and the EPA has submitted an interim objection letter regarding the allowable amount of heat that can be contained in the returned water. Until this matter is resolved, KCP&L continues to operate under its current permit. Future water permit renewals at KCP&L's Iatan Station and at GMO's Sibley and Lake Road Stations could also be impacted by the allowable amount of heat that can be contained in the returned water. Great Plains Energy and KCP&L cannot predict the outcome of these matters; however, while less significant outcomes are possible, these matters may require a reduction in generation, installation of cooling towers or other technology to cool the water, or both, any of which could have a significant impact on Great Plains Energy's and KCP&L's results of operations, financial position and cash flows.

In September 2015, the EPA finalized a revision of the technology-based effluent limitations guidelines and standards regulation to make the existing controls on discharges from steam electric power plants more stringent. The final rule sets the first federal limits on the levels of toxic metals in wastewater that can be discharged from power plants. The new requirements for existing power plants would be phased in between 2018 and 2023.

Further, the possible effects of climate change, including potentially increased temperatures and reduced precipitation, could make it more difficult and costly to comply with the current and final permit requirements.

Solid Waste

Solid and hazardous waste generation, storage, transportation, treatment and disposal are regulated at the federal and state levels under various laws and regulations. In April 2015, the EPA published final regulations to regulate coal combustion residuals (CCRs) under the Resource Conservation and Recovery Act (RCRA) Subtitle D to address the risks from the disposal of CCRs generated from the combustion of coal at electric generating facilities. The Companies principally use coal in generating electricity and dispose of CCRs in both on-site facilities and facilities owned by third parties. Current and future EPA regulations regarding the handling, disposal and remediation of CCRs could have a material adverse effect on the Companies' results of operations, financial position and cash flows.

Remediation

Under current law, the Companies are also generally responsible for any liabilities associated with the environmental condition of their properties and other properties at which the Companies arranged for the disposal or treatment of hazardous substances, including properties that they have previously owned or operated, such as manufactured gas plants (MGP), regardless of whether they were responsible for the contamination or whether the liabilities arose before, during or after the time they owned or operated the properties or arranged for the disposal or treatment of hazardous substances.

Due to all of the above, the Companies' projected capital and other expenditures for environmental compliance are subject to significant uncertainties, including the timing of implementation of any new or modified environmental requirements, the limits imposed by such requirements and the types and costs of the compliance alternatives selected by the Companies. As a result, costs to comply with environmental requirements cannot be estimated with certainty, and actual costs could be significantly higher than projections. New environmental laws and regulations affecting the operations of the Companies may be adopted, and new interpretations of existing laws and regulations could be adopted or become applicable to the Companies or their facilities, any of which may materially adversely affect the Companies' business, adversely affect the Companies' ability to continue operating its power plants as currently done and substantially increase environmental expenditures or liabilities in the future.

Financial Risks:

Financial market disruptions and declines in credit ratings may increase financing costs and/or limit access to the credit markets, which may adversely affect liquidity and results.
The Companies' capital requirements are expected to be substantial over the next several years. The Companies rely on access to short-term money markets, revolving credit facilities provided by financial institutions and long-term capital markets as significant sources of liquidity for capital requirements not satisfied by cash flows from operations. The Companies also rely on bank-provided credit facilities for credit support, such as letters of credit, to support operations. The amount of credit support required for operations varies and is impacted by a number of factors.

Great Plains Energy, KCP&L, GMO and certain of their securities are rated by Moody's Investors Service and Standard & Poor's. Following the announcement of the anticipated acquisition of Westar, Moody's Investors Service placed its long-term ratings on Great Plains Energy on review for downgrade and Standard & Poor's Ratings Services revised the outlook on Great Plains Energy, KCP&L and GMO from stable to negative. These ratings impact the Companies' cost of funds and Great Plains Energy's ability to provide credit support for its subsidiaries. The interest rates on borrowings under the Companies' revolving credit agreements and on a portion of Great Plains Energy's debt are subject to increase as their respective credit ratings decrease. The amount of collateral or other credit support required under power supply and certain other agreements is also dependent on credit ratings.

Conditions in the United States capital and credit markets may deteriorate in the future for a variety of reasons, including, among others: instability in global markets, political uncertainty in the United States or abroad, fluctuations in the price of oil, geopolitical instability or other unforeseen events both in the United States and around the world. Adverse market conditions or decreases in Great Plains Energy's, KCP&L's or GMO's credit ratings could have material adverse effects on the Companies. These effects could include, among others: reduced access to capital and increased cost of funds; dilution resulting from equity issuances at reduced prices; changes in the type and/or increases in the amount of collateral or other credit support obligations required to be posted with contractual counterparties; increased nuclear decommissioning trust and pension and other post-retirement benefit plan funding requirements; rate case disallowance of KCP&L's or GMO's costs of capital; reductions in or delays of capital expenditures; or reductions in Great Plains Energy's ability to provide credit support for its subsidiaries. Any of these results could adversely affect the Companies' results of operations, financial position and cash flows. In addition, market disruption and volatility could have an adverse impact on the Companies' lenders, suppliers and other counterparties or customers, causing them to fail to meet their obligations.

Great Plains Energy has guaranteed some of GMO's long-term and short-term debt and payments under these guarantees may adversely affect Great Plains Energy's liquidity.
Great Plains Energy has issued guarantees covering $96.6 million of GMO's long-term debt. Great Plains Energy also guarantees GMO's commercial paper program. At December 31, 2016, GMO had $201.9 million of commercial paper outstanding. The guarantees obligate Great Plains Energy to pay amounts owed by GMO directly to the holders of the guaranteed debt in the event GMO defaults on its payment obligations. Great Plains Energy may also guarantee debt that GMO may issue in the future. Any guarantee payments could adversely affect Great Plains Energy's liquidity.

The inability of Great Plains Energy's subsidiaries to provide sufficient dividends to Great Plains Energy, or the inability otherwise of Great Plains Energy to pay dividends to its shareholders and meet its financial obligations would have an adverse effect.
Great Plains Energy is a holding company with no significant operations of its own. The primary source of funds for payment of dividends to its shareholders and its other financial obligations is dividends paid to it by its subsidiaries, particularly KCP&L and GMO. The ability of Great Plains Energy's subsidiaries to pay dividends or make other distributions, and accordingly, Great Plains Energy's ability to pay dividends on its common stock and meet its financial obligations principally depends on the actual and projected earnings and cash flow, capital requirements and general financial position of its subsidiaries, as well as regulatory factors, financial covenants, general business conditions and other matters.

In addition, Great Plains Energy, KCP&L and GMO are subject to certain corporate and regulatory restrictions and financial covenants that could affect their ability to pay dividends. Great Plains Energy's articles of incorporation restrict the payment of common stock dividends in the event common equity is 25% or less of total capitalization. In addition, if preferred stock dividends are not declared and paid when scheduled, Great Plains Energy could not declare or pay common stock dividends or purchase any common shares. If the unpaid preferred stock dividends are in arrears for six or more quarters, whether or not consecutive, the preferred shareholders will be entitled to name two directors to the Great Plains Energy Board of Directors. Furthermore, pursuant to settlement agreements with certain intervenors in Missouri that are pending MPSC approval with respect to the merger, Great Plains Energy agreed that in the event that KCP&L's or GMO's credit ratings are downgraded below investment grade as a result of the merger, then KCP&L and GMO would be restricted from paying a dividend to Great Plains Energy unless approved by the MPSC or until their credit ratings are restored to investment grade. Certain conditions in the MPSC and KCC orders authorizing the holding company structure require Great Plains Energy and KCP&L to maintain consolidated common equity of at least 30% and 35%, respectively, of total capitalization (including only the amount of short-term debt in excess of the amount of construction work in progress). Under the Federal Power Act, KCP&L and GMO generally can pay dividends only out of retained earnings. The revolving credit agreements of Great Plains Energy, KCP&L and GMO and the note purchase agreement for GMO's Series A, B and C Senior Notes contain a covenant requiring each company to maintain a consolidated indebtedness to consolidated total capitalization ratio of not more than 0.65 to 1.00, except as the ratio relates to Great Plains Energy, which was amended in June 2016. See Note 11 to the consolidated financial statements for additional information. Great Plains Energy's Board of Directors regularly evaluates the common stock dividend policy and determines an appropriate dividend each quarter, after taking into account such factors as, among other things, earnings, financial condition and cash flows from KCP&L and GMO, as well as general economic conditions. While the corporate and regulatory restrictions and financial covenants discussed above are not expected to affect the Companies' ability to pay dividends at the current level in the foreseeable future, Great Plains Energy cannot assure common shareholders that the dividend will be paid in the future or that, if paid, dividends will be at the same amount or with the same frequency as in the past.

Market performance, increased retirements and retirement plan regulations could significantly impact retirement plan funding requirements and associated cash needs and expenses.
Substantially all of the Companies' and WCNOC's employees participate in defined benefit retirement and other post-retirement plans. Former employees also have accrued benefits in defined benefit retirement and other post-retirement plans. The costs of these plans depend on a number of factors, including the rates of return on plan assets, the level and nature of the provided benefits, discount rates, the interest rates used to measure required minimum funding levels, changes in benefit design, changes in laws or regulations, and the Companies' required or voluntary contributions to the plans. The Companies currently have substantial unfunded liabilities under these plans. Also, if the rate of retirements exceeds planned levels, or if these plans experience adverse market returns on investments, or if interest rates materially fall, the Companies' contributions to the plans could rise substantially over historical levels. In addition, changes in accounting rules and assumptions related to future costs, returns on investments, interest rates and other actuarial assumptions, including projected retirements, could have a significant impact on the Companies' results of operations, financial position and cash flows.

The use of derivative contracts in the normal course of business could result in losses that could negatively impact the Companies' results of operations, financial position and cash flows.
The Companies use derivative instruments, such as swaps, options, futures and forwards, to manage commodity and financial risks. Losses could be recognized as a result of volatility in the market values of these contracts, if a counterparty fails to perform, or if the underlying transactions which the derivative instruments are intended to hedge fail to materialize. In the absence of actively quoted market prices and pricing information from external sources, the valuation of these financial instruments can involve management's judgment or the use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of these contracts.

As a service provider to GMO, KCP&L may have exposure to GMO's financial performance and operations.
GMO has no employees of its own. KCP&L employees operate and manage GMO's properties, and KCP&L charges GMO for the cost of these services. These arrangements may pose risks to KCP&L, including possible

claims arising from actions of KCP&L employees in operating GMO's properties and providing other services to GMO. KCP&L's claims for reimbursement for services provided to GMO are unsecured and rank equally with other unsecured obligations of GMO. KCP&L's ability to be reimbursed for the costs incurred for the benefit of GMO depends on the financial ability of GMO to make such payments.

Customer and Weather-Related Risks:

The results of operations, financial position and cash flows of the Companies can be materially affected by changes in customer electricity consumption.
Changes in customer electricity consumption due to sustained financial market disruptions, downturns or sluggishness in the economy, technological advances, energy efficiency or other factors may adversely affect the Companies' results of operations, financial position and cash flows.

Technological advances, energy efficiency, or other energy conservation measures could reduce customer electricity consumption. KCP&L and GMO generate electricity at central station power plants to achieve economies of scale and produce electricity at a competitive cost. There are distributed generation technologies that produce electricity, including microturbines, wind turbines, fuel cells and solar cells, that have recently become more cost competitive. If this trend continues, the Companies customer electricity consumption could be reduced. Changes in technology could also alter the channels through which the Companies’ customers purchase or use electricity, which could reduce the Companies customer electricity consumption.

Weather is a major driver of the Companies' results of operations, financial position and cash flow.
Weather conditions directly influence the demand for electricity and natural gas and affect the price of energy commodities. Great Plains Energy and KCP&L are significantly impacted by seasonality, with approximately one-third of their retail electric revenues recorded in the third quarter. Unusually mild winter or summer weather can adversely affect sales. In addition, severe weather, including but not limited to tornados, snow, rain, flooding and ice storms can be destructive causing outages and property damage that can potentially result in additional expenses, lower revenues and additional capital restoration costs. KCP&L's and GMO's rates may not always be adjusted timely and adequately to reflect these increased costs. Some of the Companies' generating stations utilize water from the Missouri River for cooling purposes. Low water and flow levels can increase maintenance costs at these stations and, if these levels were to get low enough, could require modifications to plant operations. The possible effects of climate change (such as increased temperatures, increased occurrence of severe weather or reduced precipitation, among other possible results) could potentially increase the volatility of demand and prices for energy commodities, increase the frequency and impact of severe weather, increase the frequency of flooding or decrease water and flow levels. To the extent the frequency of extreme weather events increases, this could increase the Companies' cost in providing service.

Operational Risks:

Operational risks may adversely affect the Companies' results of operations, financial position and cash flows.
The operation of the Companies' electric generation, transmission, distribution and information systems involves many risks, including breakdown or failure of equipment, aging infrastructure, processes and personnel performance; problems that delay or increase the cost of returning facilities to service after outages; limitations that may be imposed by equipment conditions or environmental, safety or other regulatory requirements; fuel supply or fuel transportation reductions or interruptions; labor disputes; difficulties with the implementation or continued operation of information systems; transmission scheduling constraints; and catastrophic events such as fires, floods, droughts, explosions, terrorism, cyber threats, severe weather or other similar occurrences. Furthermore, to the extent that a cyber attack was successful, customer and employee information may be stolen, equipment may be destroyed or damaged and operations may be disrupted. Any such equipment or system outage or constraint can, among other things:

- in the case of generation equipment, affect operating costs, increase capital requirements and costs, increase purchased power volumes and costs and reduce wholesale sales opportunities;

- in the case of transmission equipment, affect operating costs, increase capital requirements and costs, require changes in the source of generation and affect wholesale sales opportunities and the ability to meet regulatory reliability and security requirements;
- in the case of distribution systems, affect revenues and operating costs, increase capital requirements and costs, and affect the ability to meet regulatory service metrics and customer expectations; and
- in the case of information systems, affect the control and operations of generation, transmission, distribution, customer information and other business operations and processes, increase operating costs, increase capital requirements and costs, and affect the ability to meet regulatory reliability and security requirements and customer expectations.

With the exception of Hawthorn No. 5, which was substantially rebuilt in 2001, and Iatan No. 2, which was completed in 2010, all of KCP&L's and GMO's coal-fired generating units and its nuclear generating unit were constructed prior to 1986. The age of these generating units increases the risk of unplanned outages, reduced generation output and higher maintenance expense. Training, preventive maintenance and other programs have been implemented, but there is no assurance that these programs will prevent or minimize future breakdowns or failures of the Companies' generation facilities or increased maintenance expense. Furthermore, aging transmission and distribution facilities are more prone to failure than new facilities, which results in higher maintenance expense and the need to replace these facilities with new infrastructure. The higher maintenance costs and capital expenditures for new replacement infrastructure could cause additional rate volatility for the Companies' customers, resistance by the Companies' regulators to allow customer rate increases and/or regulatory lag.

The Companies currently have general liability and property insurance in place to cover their facilities in amounts that management considers appropriate. These policies, however, do not cover the Companies' transmission or distribution systems, and the cost of repairing damage to these systems may adversely affect the Companies' results of operations, financial position and cash flows. Such policies are subject to certain limits and deductibles and do not include business interruption coverage. Insurance coverage may not be available in the future at reasonable costs or on commercially reasonable terms, and the insurance proceeds received for any loss of, or any damage to, any of the Companies' facilities may not be sufficient to restore the loss or damage.

These and other operating events may reduce the Companies' revenues, increase their costs, or both, and may materially affect their results of operations, financial position and cash flows.

Cyber attacks and other disruptions to facilities could interfere with operations, expose the Companies, customers or employees to a risk of loss and could cause reputational and financial harm.
Electric utilities and other operators of critical energy infrastructure, like KCP&L and GMO, may face a heightened risk of cyber attack. The Companies' facilities could be direct targets or indirect casualties of any such cyber attacks. The Companies' business relies on information technology for the generation, transmission and distribution of electricity, their primary business, as well as in secondary operational functions, including supply chain, and invoicing and collecting payments from customers. In the ordinary course of business, the Companies collect, store and transmit sensitive data including operating information, proprietary business information belonging to the Companies and third parties and personal information belonging to customers and employees. To the extent that a cyber attack was successful, customer and employee information may be stolen, equipment may be destroyed or damaged and operations of the generation fleet and/or reliability of the transmission and distribution system may be disrupted. In such an event, the Companies may experience substantial loss of revenues, material response costs and other financial loss, including the increased cost of insurance coverage. The Companies could also be subject to litigation, increased regulation and reputational damage. Any of the foregoing could have a material adverse impact on the Companies' results of operations, financial position and cash flows.

The Companies are subject to information security risks and risks of unauthorized access to their systems.
In the course of their businesses, the Companies handle a range of system security and sensitive customer information. KCP&L and GMO are subject to laws and rules issued by different agencies concerning safeguarding and maintaining the confidentiality of this information. A security breach of the utilities' information systems such as theft or the inappropriate release of certain types of information, including confidential customer information or

system operating information, could have a material adverse impact on the results of operations, financial position and cash flows of the Companies.

KCP&L and GMO operate in a highly regulated industry that requires the continued operation of sophisticated information technology systems and network infrastructures. Despite implementation of security measures, the technology systems are vulnerable to disability, failures, employee error or malfeasance, or unauthorized access. Such failures or breaches of the systems could impact the reliability of generation, transmission and distribution systems, result in legal claims and proceedings, damage the Companies' reputation and also subject the Companies to financial harm. If the technology systems were to fail or be breached and not recovered in a timely way, critical business functions could be impaired and sensitive confidential data could be compromised, which could have a material adverse impact on the Companies' results of operations, financial position and cash flows.

The cost and schedule of capital projects may materially change and expected performance may not be achieved.
Great Plains Energy's and KCP&L's businesses are capital intensive. The Companies currently have significant capital projects pending and may also have significant capital projects in the future. The risks of any capital project include: that actual costs may exceed estimated costs due to inflation or other factors; risks associated with the incurrence of additional debt or the issuance of additional equity to fund such projects; delays that may occur in obtaining permits and materials; the failure of suppliers and contractors to perform as required under their contracts; inadequate availability or increased cost of equipment, materials or qualified craft labor; delays related to inclement weather; the scope, cost and timing of projects may change due to new or changed environmental requirements, health and safety laws or other factors; and other events beyond the Companies' control may occur that may materially affect the schedule, cost and performance of these projects.

These and other risks could materially increase the estimated costs of capital projects, delay the in-service dates of projects, adversely affect the performance of the projects, and/or require the Companies to purchase additional electricity to supply their respective retail customers until the projects are completed. Thus, these risks may significantly affect the Companies' results of operations, financial position and cash flows.

Failure of one or more generation plant co-owners to pay their share of construction or operations and maintenance costs could increase the Companies' costs and capital requirements.
KCP&L owns 47% of Wolf Creek, 50% of La Cygne Station, 70% of Iatan No. 1 and 55% of Iatan No. 2. GMO owns 18% of both Iatan units and 8% of Jeffrey Energy Center. The remaining portions of these facilities are owned by other utilities that are contractually obligated to pay their proportionate share of capital and other costs.

While the ownership agreements provide that a defaulting co-owner's share of the electricity generated can be sold by the non-defaulting co-owners, there is no assurance that the revenues received will recover the increased costs borne by the non-defaulting co-owners. Occurrence of these or other events could materially increase the Companies' costs and capital requirements.

KCP&L is exposed to risks associated with the ownership and operation of a nuclear generating unit, which could result in an adverse effect on the Companies' business and financial results.
KCP&L owns 47% of Wolf Creek. The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities, including Wolf Creek. In the event of non-compliance, the NRC has the authority to impose fines, shut down the facilities, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. Additionally, the non-compliance of other nuclear facility operators with applicable regulations or the occurrence of a serious nuclear incident anywhere in the world could result in increased regulation of the nuclear industry as a whole. Any revised safety requirements promulgated by the NRC could result in substantial capital expenditures at Wolf Creek.

Wolf Creek has the lowest fuel cost per MWh of any of KCP&L's generating units. An extended outage of Wolf Creek, whether resulting from NRC action, an incident at the plant or otherwise, could have a material adverse effect on KCP&L's results of operations, financial position and cash flows in the event KCP&L incurs higher replacement power and other costs that are not recovered through rates or insurance. If a long-term outage occurred, the state regulatory commissions could reduce rates by excluding the Wolf Creek investment from rate base. Wolf Creek was constructed prior to 1986 and the age of Wolf Creek increases the risk of unplanned outages and results in higher maintenance costs.

Ownership and operation of a nuclear generating unit exposes KCP&L to risks regarding decommissioning costs at the end of the unit's life. KCP&L contributes annually based on estimated decommissioning costs to a tax-qualified trust fund to be used to decommission Wolf Creek. The funding level assumes a projected level of return on trust assets. If the actual return on trust assets is below the projected level or actual decommissioning costs are higher than estimated, KCP&L could be responsible for the balance of funds required and may not be allowed to recover the balance through rates.

KCP&L is also exposed to other risks associated with the ownership and operation of a nuclear generating unit, including, but not limited to, (i) potential liability associated with the potential harmful effects on the environment and human health resulting from the operation of a nuclear generating unit, (ii) the storage, handling, disposal and potential release (by accident, through third-party actions or otherwise) of radioactive materials and (iii) uncertainties with respect to contingencies and assessments if insurance coverage is inadequate. Under the structure for insurance among owners of nuclear generating units, KCP&L is also liable for potential retrospective premium assessments (subject to a cap) per incident at any commercial reactor in the country and losses in excess of insurance coverage.

The structure of the regional power market in which the Companies operate could have an adverse effect on the Companies' results of operations, financial position and cash flows.
In March 2014, the SPP launched its Integrated Marketplace. Similar to other RTO or ISO markets, this marketplace determines which generating units among market participants should run, within the operating constraints of a unit, at any given time for maximum cost-effectiveness. In the event that KCP&L's and GMO's generating units are not among the lowest cost generating units operating within the market, KCP&L and GMO could experience decreased levels of wholesale electricity sales.

A market for Transmission Congestion Rights (TCR) is also included as part of the Integrated Marketplace. TCRs are financial instruments used to hedge transmission congestion charges. Both KCP&L and GMO acquire TCRs for the purpose of hedging against transmission congestion charges. There is a risk that KCP&L and GMO could incorrectly model the amount of TCRs needed, or that the TCRs acquired could be ineffective in hedging against transmission congestion charges which could lead to increased purchased power costs.

The rules governing the various regional power markets may change from time to time and such changes could impact the Companies' costs and revenues. Because the manner in which RTO's or ISO's will evolve is unclear, the Companies are unable to assess fully the impact of these changes.

Litigation Risks:

The outcome of legal proceedings cannot be predicted. An adverse finding could have a material adverse effect on the Companies' results of operations, financial position and cash flows.
The Companies are party to various material litigation and regulatory matters arising out of their business operations. The ultimate outcome of these matters cannot presently be determined, nor, in many cases, can the liability that could potentially result from a negative outcome in each case be reasonably estimated. The liability that the Companies may ultimately incur with respect to any of these cases in the event of a negative outcome may be in excess of amounts currently reserved and insured against with respect to such matters.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Electric Utility Generation Resources

	Unit	Location	Year Completed	Estimated 2017 MW Capacity	Primary Fuel
Base Load	Iatan No. 2	Missouri	2010	482 [a]	Coal
	Wolf Creek	Kansas	1985	549 [a]	Nuclear
	Iatan No. 1	Missouri	1980	490 [a]	Coal
	La Cygne Nos. 1 and 2	Kansas	1973, 1977	699 [a]	Coal
	Hawthorn No. 5 [b]	Missouri	1969	564	Coal
	Montrose Nos. 2 and 3	Missouri	1960, 1964	334	Coal
Peak Load	West Gardner Nos. 1, 2, 3 and 4	Kansas	2003	314	Natural Gas
	Osawatomie	Kansas	2003	76	Natural Gas
	Hawthorn Nos. 6 and 9	Missouri	2000	235	Natural Gas
	Hawthorn No. 8	Missouri	2000	79	Natural Gas
	Hawthorn No. 7	Missouri	2000	78	Natural Gas
	Northeast Black Start Unit	Missouri	1985	2	Oil
	Northeast Nos. 17 and 18	Missouri	1977	105	Oil
	Northeast Nos. 13 and 14	Missouri	1976	95	Oil
	Northeast Nos. 15 and 16	Missouri	1975	106	Oil
	Northeast Nos. 11 and 12	Missouri	1972	93	Oil
Wind	Spearville 2 Wind Energy Facility [c]	Kansas	2010	48	Wind
	Spearville 1 Wind Energy Facility [d]	Kansas	2006	101	Wind
Total KCP&L				4,450	
Base Load	Iatan No. 2	Missouri	2010	159 [a]	Coal
	Iatan No. 1	Missouri	1980	126 [a]	Coal
	Jeffrey Energy Center Nos. 1, 2 and 3	Kansas	1978, 1980, 1983	172 [a]	Coal
	Sibley Nos. 1, 2 and 3	Missouri	1960, 1962, 1969	448	Coal
Peak Load	Lake Road Nos. 2 and 4	Missouri	1957, 1967	115	Natural Gas
	South Harper Nos. 1, 2 and 3	Missouri	2005	303	Natural Gas
	Crossroads Energy Center	Mississippi	2002	292	Natural Gas
	Ralph Green No. 3	Missouri	1981	71	Natural Gas
	Greenwood Nos. 1, 2, 3 and 4	Missouri	1975-1979	242	Natural Gas/Oil
	Lake Road No. 5	Missouri	1974	62	Natural Gas/Oil
	Lake Road Nos. 1 and 3	Missouri	1951, 1962	24	Natural Gas/Oil
	Lake Road Nos. 6 and 7	Missouri	1989, 1990	42	Oil
	Nevada	Missouri	1974	18	Oil
Total GMO				2,074	
Total Great Plains Energy				6,524	

[a] Share of a jointly owned unit.
[b] In 2001, a new boiler, air quality control equipment and an uprated turbine was placed in service at the Hawthorn Generating Station.
[c] Accredited capacity is 14 MW pursuant to SPP reliability standards.
[d] Accredited capacity is 29 MW pursuant to SPP reliability standards.

KCP&L owns 50% of La Cygne Nos. 1 and 2, 70% of Iatan No. 1, 55% of Iatan No. 2 and 47% of Wolf Creek. GMO owns 18% of each of Iatan Nos. 1 and 2 and 8% of Jeffrey Energy Center Nos. 1, 2 and 3.

Electric Utility Transmission and Distribution Resources
Electric utility's electric transmission system interconnects with systems of other utilities for reliability and to permit wholesale transactions with other electricity suppliers. Electric utility has approximately 3,600 circuit miles of transmission lines, 15,600 circuit miles of overhead distribution lines and 7,100 circuit miles of underground distribution lines in Missouri and Kansas. Electric utility has all material franchise rights necessary to sell electricity within its retail service territory. Electric utility's transmission and distribution systems are continuously monitored for adequacy to meet customer needs. Management believes the current systems are adequate to serve customers.

Electric Utility General
Electric utility's generating plants are located on property owned (or co-owned) by KCP&L or GMO, except the Spearville Wind Energy Facilities which are located on easements, and the Crossroads Energy Center and the South Harper Facility which are contractually controlled. Electric utility's service centers, electric substations and a portion of its transmission and distribution systems are located on property owned or leased by electric utility. Electric utility's transmission and distribution systems are for the most part located above or underneath highways, streets, other public places or property owned by others. Electric utility believes that it has satisfactory rights to use those places or properties in the form of permits, grants, easements, licenses or franchise rights; however, it has not necessarily undertaken efforts to examine the underlying title to the land upon which the rights rest. Great Plains Energy's and KCP&L's headquarters are located in leased office space.

Substantially all of the fixed property and franchises of KCP&L, which consist principally of electric generating stations, electric transmission and distribution lines and systems, and buildings (subject to exceptions, reservations and releases), are subject to a General Mortgage Indenture and Deed of Trust dated as of December 1, 1986, as supplemented. Mortgage bonds totaling $510.5 million were outstanding at December 31, 2016.

A portion of the fixed property and franchises of GMO are subject to a General Mortgage Indenture and Deed of Trust dated as of April 1, 1946, as supplemented. Mortgage bonds totaling $5.7 million were outstanding at December 31, 2016.

ITEM 3. LEGAL PROCEEDINGS

Other Proceedings
The Companies are parties to various lawsuits and regulatory proceedings in the ordinary course of their respective businesses. For information regarding material lawsuits and proceedings, see Notes 2, 6, 15 and 16 to the consolidated financial statements. Such information is incorporated herein by reference.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

GREAT PLAINS ENERGY

Great Plains Energy's common stock is listed on the New York Stock Exchange under the symbol "GXP". At February 21, 2017, Great Plains Energy's common stock was held by 14,886 shareholders of record. Information relating to market prices and cash dividends on Great Plains Energy's common stock is set forth in the following table.

	Common Stock Price Range [(a)]				Common Stock Dividends Declared		
	2016		2015				
Quarter	High	Low	High	Low	2017	2016	2015
First	$ 32.26	$ 26.34	$ 30.06	$ 25.80	$ 0.275 [(b)]	$ 0.2625	$ 0.245
Second	32.68	28.35	27.52	24.16		0.2625	0.245
Third	31.22	26.53	27.35	24.21		0.2625	0.245
Fourth	28.60	26.20	28.02	25.74		0.275	0.2625

(a) Based on closing stock prices.
(b) Declared February 14, 2017, and payable March 20, 2017, to shareholders of record as of February 27, 2017.

Dividend Restrictions

For information regarding dividend restrictions, see Note 13 to the consolidated financial statements.

Purchases of Equity Securities

Great Plains Energy had no purchases of its equity securities during the three months ended December 31, 2016.

KCP&L

KCP&L is a wholly owned subsidiary of Great Plains Energy, which holds the one share of issued and outstanding KCP&L common stock.

Dividend Restrictions

For information regarding dividend restrictions, see Note 13 to the consolidated financial statements.

ITEM 6. SELECTED FINANCIAL DATA

Year Ended December 31	2016	2015	2014[a]	2013[a]	2012[a]
Great Plains Energy	(dollars in millions except per share amounts)				
Operating revenues	$ 2,676	$ 2,502	$ 2,568	$ 2,446	$ 2,310
Net income	$ 290	$ 213	$ 243	$ 250	$ 200
Basic earnings per common share	$ 1.61	$ 1.37	$ 1.57	$ 1.62	$ 1.36
Diluted earnings per common share	$ 1.61	$ 1.37	$ 1.57	$ 1.62	$ 1.35
Total assets at year end [a]	$ 13,570	$ 10,739	$ 10,453	$ 9,770	$ 9,626
Total redeemable preferred stock, mandatorily redeemable preferred securities and long-term debt (including current maturities) [a]	$ 3,747	$ 3,746	$ 3,481	$ 3,492	$ 2,999
Cash dividends per common share	$ 1.0625	$ 0.9975	$ 0.935	$ 0.8825	$ 0.855
SEC ratio of earnings to combined fixed charges and preferred dividend requirements	2.54	2.58	2.72	2.75	2.31
KCP&L					
Operating revenues	$ 1,875	$ 1,714	$ 1,731	$ 1,671	$ 1,580
Net income	$ 225	$ 153	$ 162	$ 169	$ 142
Total assets at year end [a]	$ 8,058	$ 7,815	$ 7,495	$ 6,821	$ 6,689
Total redeemable preferred stock, mandatorily redeemable preferred securities and long-term debt (including current maturities) [a]	$ 2,565	$ 2,563	$ 2,297	$ 2,294	$ 1,887
SEC ratio of earnings to fixed charges	3.30	2.57	2.69	2.76	2.58

[a] Adjusted for adoption of Accounting Standards Update (ASU) No. 2015-03, *Simplifying the Presentation of Debt Issuance Costs*.

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

GREAT PLAINS ENERGY INCORPORATED

EXECUTIVE SUMMARY

Description of Business

Great Plains Energy is a public utility holding company and does not own or operate any significant assets other than the stock of its subsidiaries and cash and cash equivalents and a time deposit to be used to fund a portion of the cash consideration for the anticipated acquisition of Westar.

Great Plains Energy's sole reportable business segment is electric utility. Electric utility consists of KCP&L, a regulated utility, GMO's regulated utility operations and GMO Receivables Company. Electric utility has approximately 6,500 MWs of owned generating capacity and engages in the generation, transmission, distribution and sale of electricity to approximately 855,700 customers in the states of Missouri and Kansas. Electric utility's retail electricity rates are comparable to the national average of investor-owned utilities.

Great Plains Energy's corporate and other activities not included in the sole reportable business segment includes GMO activity other than its regulated utility operations, GPETHC and unallocated corporate charges including certain costs to achieve the anticipated acquisition of Westar.

Anticipated Acquisition of Westar Energy, Inc.

On May 29, 2016, Great Plains Energy entered into a Merger Agreement by and among Great Plains Energy, Westar, and, from and after its accession to the Merger Agreement, Merger Sub. Pursuant to the Merger

Agreement, subject to the satisfaction or waiver of certain conditions, Merger Sub will merge with and into Westar, with Westar continuing as the surviving corporation. Upon closing, pursuant to the Merger Agreement, Great Plains Energy will acquire Westar for (i) $51.00 in cash and (ii) a number, rounded to the nearest 1/10,000 of a share, of Great Plains Energy common stock equal to an exchange ratio that may vary between 0.2709 and 0.3148, based upon the volume-weighted average price per share of Great Plains Energy common stock during a 20 consecutive full trading day period ending on (and including) the third trading day immediately prior to the closing date of the merger, for each share of Westar common stock issued and outstanding immediately prior to the effective time of the merger, with Westar becoming a wholly owned subsidiary of Great Plains Energy.

Great Plains Energy's anticipated acquisition of Westar was unanimously approved by the Great Plains Energy Board and the Westar Board, has received the required approvals of each of Great Plains Energy's and Westar's shareholders and The Federal Communications Commission (FCC), and has received early termination of the waiting period under the HSR Act with respect to antitrust review. The anticipated acquisition remains subject to regulatory approvals from KCC, the MPSC, NRC and FERC; as well as other customary conditions.

On October 3, 2016, Great Plains Energy completed registered public offerings of 60.5 million shares of common stock for total net proceeds of $1.55 billion and 17.3 million depositary shares each representing a 1/20th interest in a share of Great Plains Energy's Series B Preferred Stock for total net proceeds of $836.2 million. The proceeds from these offerings will be used to fund a portion of the cash consideration for the anticipated acquisition.

See Note 2 to the consolidated financial statements for more information regarding the acquisition.

Earnings Overview

Great Plains Energy's 2016 earnings available for common shareholders increased to $273.5 million or $1.61 per share from $211.4 million or $1.37 per share in 2015 driven primarily by new retail rates and cost recovery mechanisms; warmer weather; a performance incentive for energy efficiency programs under the Missouri Energy Efficiency Investment Act (MEEIA) and a decrease in interest charges; partially offset by a decrease in weather-normalized retail demand; costs to achieve the anticipated acquisition of Westar; an increase in utility operating and maintenance expense; depreciation and amortization expense and general taxes; higher income tax expense; and increased preferred stock dividend requirements.

In addition, a higher number of average shares outstanding due to Great Plains Energy's registered public offering of 60.5 million shares of common stock in October 2016 diluted 2016 earnings per share by $0.15.

For additional information regarding the change in earnings, refer to the Great Plains Energy Results of Operations and the Electric Utility Results of Operations sections within this Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A).

Adjusted Earnings (Non-GAAP) and Adjusted Earnings Per Share (Non-GAAP)

Great Plains Energy's adjusted earnings (non-GAAP) and adjusted earnings per share (non-GAAP) for 2016 were $286.0 million and $1.85, respectively. For 2015 and 2014, adjusted earnings (non-GAAP) and adjusted earnings per share (non-GAAP) were the same as GAAP earnings and GAAP earnings per share at $211.4 million and $1.37 and $241.2 million and $1.57, respectively. In addition to earnings available for common shareholders and diluted earnings per common share, Great Plains Energy's management uses adjusted earnings (non-GAAP) and adjusted earnings per share (non-GAAP) to evaluate earnings and earnings per share without the impact of the anticipated acquisition of Westar. Adjusted earnings (non-GAAP) and adjusted earnings per share (non-GAAP) excludes certain costs, expenses, gains, losses and the per share dilutive effect of equity issuances resulting from the anticipated acquisition. This information is intended to enhance an investor's overall understanding of results. Adjusted earnings (non-GAAP) and adjusted earnings per share (non-GAAP) are used internally to measure performance against budget and in reports for management and the Great Plains Energy Board. Adjusted earnings (non-GAAP) and adjusted earnings per share (non-GAAP) are financial measures that are not calculated in accordance with GAAP and may not be comparable to other companies' presentations or more useful than the GAAP information provided elsewhere in this report.

The following table provides a reconciliation between earnings available for common shareholders and diluted earnings per common share as determined in accordance with GAAP and adjusted earnings (non-GAAP) and adjusted earnings per share (non-GAAP):

	2016	
Reconciliation of GAAP to Non-GAAP		**Earnings per diluted share**
	(millions, except per share amounts)	
Earnings available for common shareholders	$ 273.5	$ 1.61
Costs to achieve the anticipated acquisition of Westar:		
Operating expense, pre-tax [a]	34.2	0.22
Financing, pre-tax [b]	35.9	0.24
Mark-to-market impacts of interest rate swaps, pre-tax [c]	(79.3)	(0.51)
Interest income, pre-tax [d]	(3.2)	(0.02)
Income tax expense [e]	9.5	0.06
Preferred stock [f]	15.4	0.10
Dilutive impact of October 2016 share issuance [g]	N/A	0.15
Adjusted earnings (non-GAAP)	$ 286.0	$ 1.85
Average Shares Outstanding		
Shares used in calculating diluted earnings per common share	169.8	
Adjustment for October 2016 share issuance [g]	(14.9)	
Shares used in calculating adjusted earnings per share (non-GAAP)	154.9	

[a] Reflects legal, advisory and consulting fees and certain severance expenses and are included in Costs to achieve the anticipated acquisition of Westar on the consolidated statements of comprehensive income.
[b] Reflects fees incurred to finance the anticipated acquisition of Westar, including fees for a bridge term loan facility, and are included in Interest charges on the consolidated statements of comprehensive income.
[c] Reflects the mark-to-market gain on interest rate swaps entered into in connection with financing the anticipated acquisition of Westar and is included in Interest charges on the consolidated statements of comprehensive income.
[d] Reflects interest income earned on the proceeds from Great Plains Energy's October 2016 equity offerings and is included in Non-operating income on the consolidated statements of comprehensive income.
[e] Reflects an income tax effect calculated at a 38.9% statutory rate, with the exception of certain non-deductible legal and financing fees.
[f] Reflects reductions to earnings available for common shareholders related to preferred stock dividend requirements for Great Plains Energy's Series B Preferred Stock issued in October 2016 and the redemption of cumulative preferred stock in August 2016, including the redemption premium, and are included in Preferred stock dividend requirements and redemption premium on the consolidated statements of comprehensive income.
[g] Reflects the average share impact of Great Plains Energy's issuance of 60.5 million shares of common stock in October 2016.

Regulatory Proceedings
See Note 6 to the consolidated financial statements for information regarding regulatory proceedings.

Impact of Recently Issued Accounting Standards
See Note 1 to the consolidated financial statements for information regarding the impact of recently issued accounting standards.

Wolf Creek Refueling Outage
Wolf Creek's latest refueling outage began on September 10, 2016 and ended on November 21, 2016. Wolf Creek's next refueling outage is planned to begin in the first quarter of 2018.

ENVIRONMENTAL MATTERS

See Note 15 to the consolidated financial statements for information regarding environmental matters.

RELATED PARTY TRANSACTIONS

See Note 18 to the consolidated financial statements for information regarding related party transactions.

CRITICAL ACCOUNTING POLICIES

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect reported amounts and related disclosures. Management considers an accounting estimate to be critical if it requires assumptions to be made that were uncertain at the time the estimate was made and changes in the estimate or different estimates that could have been used could have a material impact on Great Plains Energy's results of operations and financial position. Management has identified the following accounting policies as critical to the understanding of Great Plains Energy's results of operations and financial position. Management has discussed the development and selection of these critical accounting policies with the Audit Committee of the Great Plains Energy Board of Directors.

Pensions

Great Plains Energy incurs significant costs in providing non-contributory defined pension benefits. The costs are measured using actuarial valuations that are dependent upon numerous factors derived from actual plan experience and assumptions of future plan experience.

Pension costs are impacted by actual employee demographics (including age, life expectancies, compensation levels and employment periods), earnings on plan assets, the level of contributions made to the plan, and plan amendments. In addition, pension costs are also affected by changes in key actuarial assumptions, including anticipated rates of return on plan assets and the discount rates used in determining the projected benefit obligation and pension costs.

The assumed rate of return on plan assets was developed based on the weighted-average of long-term returns forecast for the expected portfolio mix of investments held by the plan. The assumed discount rate was selected based on the prevailing market rate of fixed income debt instruments with maturities matching the expected timing of the benefit obligation. These assumptions, updated annually at the measurement date, are based on management's best estimates and judgment; however, material changes may occur if these assumptions differ from actual events. See Note 9 to the consolidated financial statements for information regarding the assumptions used to determine benefit obligations and net costs.

The following table reflects the sensitivities associated with a 0.5% increase or a 0.5% decrease in key actuarial assumptions. Each sensitivity reflects the impact of the change based on a change in that assumption only**.**

Actuarial assumption	Change in Assumption	Impact on Projected Benefit Obligation	Impact on 2016 Pension Expense
		(millions)	
Discount rate	0.5% increase	$ (86.1)	$ (5.9)
Rate of return on plan assets	0.5% increase	—	(3.4)
Discount rate	0.5% decrease	96.9	6.1
Rate of return on plan assets	0.5% decrease	—	3.4

Pension expense for KCP&L and GMO is recorded in accordance with rate orders from the MPSC and KCC. The orders allow the difference between pension costs under GAAP and pension costs for ratemaking to be recorded as a regulatory asset or liability with future ratemaking recovery or refunds, as appropriate.

In 2016, Great Plains Energy's pension expense was $98.2 million under GAAP and $93.3 million for ratemaking. The impact on 2016 pension expense in the table above reflects the impact on GAAP pension costs. Under the

Companies' rate agreements, any increase or decrease in GAAP pension expense would be deferred in a regulatory asset or liability for future ratemaking treatment. See Note 9 to the consolidated financial statements for additional information regarding the accounting for pensions.

Market conditions and interest rates significantly affect the future assets and liabilities of the plan. It is difficult to predict future pension costs, changes in pension liability and cash funding requirements due to the inherent uncertainty of market conditions.

Regulatory Assets and Liabilities
The Company has recorded assets and liabilities on its consolidated balance sheets resulting from the effects of the ratemaking process, which would not otherwise be recorded under GAAP. Regulatory assets represent incurred costs that are probable of recovery from future revenues. Regulatory liabilities represent future reductions in revenues or refunds to customers.

Management regularly assesses whether regulatory assets and liabilities are probable of future recovery or refund by considering factors such as decisions by the MPSC, KCC or FERC in electric utility's rate case filings; decisions in other regulatory proceedings, including decisions related to other companies that establish precedent on matters applicable to electric utility; and changes in laws and regulations. If recovery or refund of regulatory assets or liabilities is not approved by regulators or is no longer deemed probable, these regulatory assets or liabilities are recognized in the current period results of operations. Electric utility's continued ability to meet the criteria for recording regulatory assets and liabilities may be affected in the future by restructuring and deregulation in the electric industry or changes in accounting rules. In the event that the criteria no longer applied to all or a portion of electric utility's operations, the related regulatory assets and liabilities would be written off unless an appropriate regulatory recovery mechanism were provided. Additionally, these factors could result in an impairment on utility plant assets. See Note 6 to the consolidated financial statements for additional information.

Impairments of Assets, Intangible Assets and Goodwill
Long-lived assets and intangible assets subject to amortization are required to be reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable as prescribed under GAAP.

Accounting rules require goodwill to be tested for impairment annually and when an event occurs indicating the possibility that an impairment exists. The goodwill impairment test is a two step process. See Note 1 to the consolidated financial statements for additional information regarding the Company's plans to adopt Accounting Standards Update (ASU) No. 2017-04 for its 2017 goodwill impairment test. The first step compares the fair value of a reporting unit to its carrying amount, including goodwill, to identify potential impairment. If the carrying amount exceeds the fair value of the reporting unit, the second step of the test is performed, consisting of assignment of the reporting unit's fair value to its assets and liabilities to determine an implied fair value of goodwill, which is compared to the carrying amount of goodwill to determine the impairment loss, if any, to be recognized in the financial statements. Great Plains Energy's regulated electric utility operations are considered one reporting unit for assessment of impairment, as they are included within the same operating segment and have similar economic characteristics.

The annual impairment test for the $169.0 million of GMO acquisition goodwill was conducted on September 1, 2016. Fair value of the reporting unit substantially exceeded the carrying amount, including goodwill; therefore, there was no impairment of goodwill.

The determination of fair value of the reporting unit consisted of two valuation techniques: an income approach consisting of a discounted cash flow analysis and a market approach consisting of a determination of reporting unit invested capital using market multiples derived from the historical revenue, earnings before interest, income taxes, depreciation and amortization (EBITDA), net utility asset values and market prices of stock of peer companies. The results of the two techniques were evaluated and weighted to determine a point within the range that management considered representative of fair value for the reporting unit, which involves a significant amount of management judgment.

The discounted cash flow analysis is most significantly impacted by two assumptions: estimated future cash flows and the discount rate applied to those cash flows. Management determined the appropriate discount rate to be based on the reporting unit's weighted average cost of capital (WACC). The WACC takes into account both the return on equity authorized by the MPSC and KCC and after-tax cost of debt. Estimated future cash flows are based on Great Plains Energy's internal business plan, which assumes the occurrence of certain events in the future, such as the outcome of future rate filings, future approved rates of return on equity, anticipated earnings/returns related to future capital investments, continued recovery of cost of service and the renewal of certain contracts. Management also makes assumptions regarding the run rate of operations, maintenance and general and administrative costs based on the expected outcome of the aforementioned events. Should the actual outcome of some or all of these assumptions differ significantly from the current assumptions, revisions to current cash flow assumptions could cause the fair value of Great Plains Energy's reporting unit under the income approach to be significantly different in future periods and could result in a future impairment charge to goodwill.

The market approach analysis is most significantly impacted by management's selection of relevant peer companies as well as the determination of an appropriate control premium to be added to the calculated invested capital of the reporting unit, as control premiums associated with a controlling interest are not reflected in the quoted market price of a single share of stock. Management determined an appropriate control premium by using an average of control premiums for recent acquisitions in the industry. Changes in results of peer companies, selection of different peer companies and future acquisitions with significantly different control premiums could result in a significantly different fair value of Great Plains Energy's reporting unit.

Income Taxes

Income taxes are accounted for using the asset/liability approach. Deferred tax assets and liabilities are determined based on the temporary differences between the financial reporting and tax bases of assets and liabilities, applying enacted statutory tax rates in effect for the year in which the differences are expected to reverse. Deferred investment tax credits are amortized ratably over the life of the related property. Deferred tax assets are also recorded for net operating losses, capital losses and tax credit carryforwards. The Company is required to estimate the amount of taxes payable or refundable for the current year and the deferred tax liabilities and assets for future tax consequences of events reflected in the Company's consolidated financial statements or tax returns. Actual results could differ from these estimates for a variety of reasons including changes in income tax laws, enacted tax rates and results of audits by taxing authorities. This process also requires management to make assessments regarding the timing and probability of the ultimate tax impact from which actual results may differ. The Company records valuation allowances on deferred tax assets if it is determined that it is more likely than not that the asset will not be realized. See Note 22 to the consolidated financial statements for additional information.

GREAT PLAINS ENERGY RESULTS OF OPERATIONS

The following table summarizes Great Plains Energy's comparative results of operations.

	2016	2015	2014
		(millions)	
Operating revenues	$ 2,676.0	$ 2,502.2	$ 2,568.2
Fuel and purchased power	(590.1)	(608.7)	(742.5)
Transmission	(84.8)	(89.1)	(74.7)
Other operating expenses	(1,003.2)	(943.9)	(910.5)
Costs to achieve the anticipated acquisition of Westar	(34.2)	—	—
Depreciation and amortization	(344.8)	(330.4)	(306.0)
Operating income	618.9	530.1	534.5
Non-operating income and expenses	2.8	3.7	12.5
Interest charges	(161.5)	(199.3)	(188.5)
Income tax expense	(172.2)	(122.7)	(115.7)
Income from equity investments	2.0	1.2	—
Net income	290.0	213.0	242.8
Preferred dividends and redemption premium	(16.5)	(1.6)	(1.6)
Earnings available for common shareholders	$ 273.5	$ 211.4	$ 241.2
Reconciliation of gross margin to operating revenue:			
Operating revenues	$ 2,676.0	$ 2,502.2	$ 2,568.2
Fuel and purchased power	(590.1)	(608.7)	(742.5)
Transmission	(84.8)	(89.1)	(74.7)
Gross margin [(a)]	$ 2,001.1	$ 1,804.4	$ 1,751.0

(a) Gross margin is a non-GAAP financial measure. See explanation of gross margin below.

2016 Compared to 2015

Electric Utility Segment

Electric utility's net income increased $68.3 million in 2016 compared to 2015 primarily due to:

- a $196.7 million increase in gross margin driven by new retail rates and cost recovery mechanisms, warmer weather and an increase in the recovery of program costs and throughput disincentive as well as a performance incentive for energy efficiency programs under MEEIA, partially offset by a decrease in weather-normalized retail demand;
- a $50.0 million increase in other operating expenses driven by an increase in pension expense, an increase in program costs for energy efficiency programs under MEEIA, an increase in plant operating and maintenance expenses, an increase in injuries and damages expense and an increase in general taxes driven by higher property taxes and higher gross receipts taxes due to an increase in retail revenues;
- $15.9 million of operating expenses for costs to achieve the anticipated acquisition of Westar;
- a $14.4 million increase in depreciation and amortization expense driven by capital additions;
- a $5.2 million increase in interest charges primarily due to an increase in interest expense in 2016 related to KCP&L's issuance of $350 million of 3.65% Senior Notes in August 2015; partially offset by a decrease in interest expense due to KCP&L's purchase in lieu of redemption of its $50.0 million and $21.9 million Environmental Improvement Revenue Refunding (EIRR) Series 2005 bonds in September 2015; and
- a $43.5 million increase in income tax expense driven by an increase in pre-tax income.

Corporate and Other Activities

Great Plains Energy's corporate and other activities loss increased $6.2 million in 2016 compared to 2015 primarily due to:

- $7.5 million of other operating expenses for the settlement of litigation at MPS Merchant in 2016;
- $18.3 million of operating expenses for costs to achieve the anticipated acquisition of Westar;
- $35.9 million of interest charges for fees incurred for a bridge term loan facility entered into in connection with the anticipated acquisition of Westar;
- a $79.3 million mark-to-market gain on interest rate swaps entered into in June 2016 to hedge against interest rate fluctuations on future issuances of long-term debt expected to be issued to finance a portion of the cash consideration for the anticipated acquisition of Westar;
- $3.2 million of interest income earned on the proceeds from Great Plains Energy's October 2016 common stock and depositary share offerings;
- $12.7 million of income tax expense related to these items; and
- $15.4 million of reductions to earnings available for common shareholders consisting of $14.8 million of dividends on Great Plains Energy's Series B Preferred Stock issued in October 2016 and $0.6 million related to the redemption of Great Plains Energy's cumulative preferred stock in August 2016.

2015 Compared to 2014

Electric Utility Segment

Electric utility's net income decreased $19.7 million in 2015 compared to 2014 primarily due to:

- a $53.4 million increase in gross margin driven by new retail rates, an increase in recovery of program costs for energy efficiency programs under MEEIA, an increase in recovery of renewable energy costs under the Renewable Energy Standard Rate Adjustment Mechanism (RESRAM), an increase in weather-normalized retail demand and an increase in other margin items, partially offset by lower wholesale margins, higher transmission expense and weather;
- a $33.8 million increase in other operating expenses primarily driven by an increase in program costs for energy efficiency programs under MEEIA, an increase in amortization of deferred renewable energy costs under RESRAM and an increase in general taxes driven by higher property taxes, partially offset by a decrease in Wolf Creek operating and maintenance expenses;
- a $24.4 million increase in depreciation and amortization expense due to capital additions;
- an $11.8 million decrease in non-operating income and expenses driven by a $13.2 million decrease in the equity component of Allowance for Funds Used During Construction (AFUDC) primarily due to a lower average construction work in progress in 2015 due to environmental upgrades at KCP&L's La Cygne Station being placed into service;
- a $7.9 million increase in interest charges primarily due to a $7.2 million decrease in the debt component of AFUDC; and
- a $4.8 million decrease in income tax expense primarily driven by decreased pre-tax income.

Corporate and Other Activities

Great Plains Energy's corporate and other activities loss increased $10.1 million in 2015 compared to 2014 primarily due to the release of uncertain tax positions related to former GMO non-regulated operations in the third quarter of 2014 which resulted in:

- $2.1 million lower after-tax interest expense in 2014; and
- $6.1 million of income tax benefits in 2014.

Gross Margin
Gross margin is a financial measure that is not calculated in accordance with GAAP. Gross margin, as used by Great Plains Energy and KCP&L, is defined as operating revenues less fuel and purchased power and transmission. Expenses for fuel and purchased power and certain transmission costs, offset by wholesale sales margin, are subject to recovery through cost adjustment mechanisms, except for KCP&L's Missouri retail operations prior to September 29, 2015, when a cost adjustment mechanism was approved. As a result, operating revenues increase or decrease in relation to a significant portion of these expenses. Management believes that gross margin provides a meaningful basis for evaluating electric utility's operations across periods because gross margin excludes the revenue effect of fluctuations in these expenses. Gross margin is used internally to measure performance against budget and in reports for management and the Great Plains Energy Board. The Companies' definition of gross margin may differ from similar terms used by other companies.

ELECTRIC UTILITY RESULTS OF OPERATIONS

The following table summarizes the electric utility segment results of operations.

	2016	2015	2014
		(millions)	
Operating revenues	$ 2,676.0	$ 2,502.2	$ 2,568.2
Fuel and purchased power	(590.1)	(608.7)	(742.5)
Transmission	(84.8)	(89.1)	(74.7)
Other operating expenses	(990.2)	(940.2)	(906.4)
Costs to achieve the anticipated acquisition of Westar	(15.9)	—	—
Depreciation and amortization	(344.8)	(330.4)	(306.0)
Operating income	650.2	533.8	538.6
Non-operating income and expenses	2.3	1.7	13.5
Interest charges	(196.1)	(190.9)	(183.0)
Income tax expense	(164.3)	(120.8)	(125.6)
Net income	$ 292.1	$ 223.8	$ 243.5
Reconciliation of gross margin to operating revenue:			
Operating revenues	$ 2,676.0	$ 2,502.2	$ 2,568.2
Fuel and purchased power	(590.1)	(608.7)	(742.5)
Transmission	(84.8)	(89.1)	(74.7)
Gross margin [(a)]	$ 2,001.1	$ 1,804.4	$ 1,751.0

(a) Gross margin is a non-GAAP financial measure. See explanation of gross margin under Great Plains Energy's Results of Operations.

Electric Utility Gross Margin and MWh Sales

The following tables summarize electric utility's gross margin and MWhs sold.

Gross Margin [a]	2016	% Change[c]	2015	% Change[c]	2014
Retail revenues			(millions)		
Residential	$ 1,092.5	9	$ 1,006.2	(2)	$ 1,025.5
Commercial	1,066.0	6	1,001.0	1	995.2
Industrial	229.6	3	222.3	(1)	225.3
Other retail revenues	20.9	3	20.4	—	20.3
Provision for rate refund	(9.6)	N/M	—	—	—
Energy efficiency (MEEIA)[b]	80.0	55	51.5	81	28.5
Total retail	2,479.4	8	2,301.4	—	2,294.8
Wholesale revenues	142.0	(3)	147.1	(34)	222.6
Other revenues	54.6	2	53.7	6	50.8
Operating revenues	2,676.0	7	2,502.2	(3)	2,568.2
Fuel and purchased power	(590.1)	(3)	(608.7)	(18)	(742.5)
Transmission	(84.8)	(5)	(89.1)	19	(74.7)
Gross margin	$ 2,001.1	11	$ 1,804.4	3	$ 1,751.0

[a] Gross margin is a non-GAAP financial measure. See explanation of gross margin under Great Plains Energy's Results of Operations.
[b] Consists of recovery of program costs of $49.3 million, $42.9 million and $20.7 million for 2016, 2015 and 2014, respectively, that have a direct offset in utility operating and maintenance expenses, recovery of throughput disincentive of $15.1 million, $8.6 million and $7.8 million for 2016, 2015 and 2014, respectively, and a performance incentive of $15.6 million for 2016.
[c] N/M - not meaningful

MWh Sales	2016	% Change	2015	% Change	2014
Retail MWh sales			(thousands)		
Residential	8,774	2	8,585	(4)	8,971
Commercial	10,796	—	10,777	(1)	10,827
Industrial	3,149	(1)	3,191	—	3,200
Other retail MWh sales	115	(1)	116	(1)	117
Total retail	22,834	1	22,669	(2)	23,115
Wholesale MWh sales	7,063	9	6,512	(14)	7,587
Total MWh sales	29,897	3	29,181	(5)	30,702

Electric utility's residential customers' usage is significantly affected by weather. Bulk power sales, the major component of wholesale sales, vary with system requirements, generating unit availability, transmission availability, fuel costs, and requirements of other electric systems. Electric utility's revenues contain certain recovery mechanisms as follows:

- KCP&L's Kansas retail rates contain an Energy Cost Adjustment (ECA) tariff. The ECA tariff reflects the projected annual amounts of fuel, purchased power, emission allowances and asset-based off-system sales margin. These projected amounts are subject to quarterly re-forecasts. Any difference between the ECA revenue collected and the actual ECA amounts for a given year (which may be positive or negative) is recorded either as a reduction of fuel and purchased power expense (for under-recoveries) or a reduction of retail revenues (for over-recoveries) and deferred as a regulatory asset or liability to be recovered from or refunded to Kansas retail customers over twelve months beginning April 1 of the succeeding year.
- KCP&L's Kansas retail rates contain a Transmission Delivery Charge (TDC) rider. The TDC tariff reflects a mixture of historical and projected costs related to transmission service, certain RTO fees, transmission rate base, and transmission operating and maintenance expense. These costs are subject to an annual true-up with a twelve month recovery period. The TDC true-up is recorded either as a reduction of transmission expense (for under-recoveries) or a reduction of retail revenues (for over-recoveries) and deferred as a

regulatory asset or liability to be recovered from or refunded to KCP&L's Kansas electric retail customers. The TDC became effective in conjunction with new retail rates on October 1, 2015.

- KCP&L's Missouri retail rates contain a Fuel Adjustment Clause (FAC) tariff under which 95% of the difference between actual fuel cost, purchased power costs, certain transmission costs and off-system sales margin and the amount provided in base rates for these costs is passed along to KCP&L's customers. The FAC cycle consists of an accumulation period of six months beginning in January and July with FAC rate approval requested every six months for a twelve month recovery period. The FAC is recorded either as a reduction of fuel and purchased power expense (for under-recoveries) or a reduction of retail revenues (for over-recoveries) and deferred as a regulatory asset or liability to be recovered from or refunded to KCP&L's electric retail customers. The FAC became effective in conjunction with new retail rates on September 29, 2015.
- GMO's electric retail rates contain a FAC tariff under which 95% of the difference between actual fuel cost, purchased power costs, certain transmission costs and off-system sales margin and the amount provided in base rates for these costs is passed along to GMO's customers. The FAC cycle consists of an accumulation period of six months beginning in June and December with FAC rate approval requested every six months for a twelve month recovery period. The FAC is recorded either as a reduction of fuel and purchased power expense (for under-recoveries) or a reduction of retail revenues (for over-recoveries) and deferred as a regulatory asset or liability to be recovered from or refunded to GMO's electric retail customers.
- GMO's steam rates contain a Quarterly Cost Adjustment (QCA) under which 85% of the difference between actual fuel costs and base fuel costs is passed along to GMO's steam customers. The QCA is recorded either as a reduction of fuel and purchased power expense (for under-recoveries) or a reduction of retail revenues (for over-recoveries) and deferred as a regulatory asset or liability to be recovered from or refunded to GMO's steam customers.

Both KCP&L and GMO offer energy efficiency and demand side management programs to their Missouri retail customers under MEEIA and recover program costs, throughput disincentive and as applicable, certain performance incentives in retail rates. KCP&L and GMO recover these items through a rider mechanism. For program costs, the difference between the amount collected and actual program costs is recorded either as a reduction to utility operating and maintenance expense (for under-recoveries) or a reduction to retail revenues (for over-recoveries) and is deferred as a regulatory asset or liability to be recovered from or refunded to customers. For throughput disincentive, the difference between the amount collected and the actual throughput disincentive is recorded as an increase to or reduction of retail revenues and is deferred as a regulatory asset or liability to be recovered from or refunded to customers. The performance incentive is recorded as an increase to retail revenues and a receivable to be recovered from customers.

Electric utility's gross margin increased $196.7 million in 2016 compared to 2015 primarily driven by:

- an estimated $111 million increase due to new retail rates and an estimated $37 million increase due to new cost recovery mechanisms for KCP&L in Missouri effective September 29, 2015, and in Kansas effective October 1, 2015;
- an estimated $38 million increase due to warmer weather with a 16% increase in cooling degree days in 2016;
- a $6.4 million increase for recovery of program costs for energy efficiency programs under MEEIA, which have a direct offset in utility operating and maintenance expense;
- a $6.5 million increase in MEEIA throughput disincentive;
- a $15.6 million MEEIA performance incentive recognized in 2016 related to the achievement of certain energy savings levels in the first cycle of KCP&L's and GMO's MEEIA programs; and
- an estimated $9 million decrease due to a decrease in weather-normalized retail demand.

Electric utility's gross margin increased $53.4 million in 2015 compared to 2014 primarily driven by:

- an estimated $36 million increase due to new retail rates for KCP&L in Missouri effective September 29, 2015, and in Kansas effective July 25, 2014 and October 1, 2015;
- a $22.2 million increase for recovery of program costs for energy efficiency programs under MEEIA, which have a direct offset in utility operating and maintenance expense, primarily due to the implementation of KCP&L's MEEIA programs in August 2014;
- a $7.2 million increase for recovery of renewable energy costs under RESRAM, which have a direct offset in utility operating and maintenance expense;
- an estimated $6 million increase from weather-normalized retail demand;
- an estimated $20 million increase in other margin items including a change in customer mix, lower fuel and purchased power expenses that are not included in fuel recovery mechanisms and an increase in transmission costs recovered through the transmission delivery charge rider that began in the fourth quarter of 2015;
- an estimated $19 million decrease due to lower wholesale margins partially offset by an estimated $14 million due to lower fuel and purchased power expense at KCP&L in Missouri, where there was no fuel recovery mechanism prior to September 29, 2015;
- an estimated $9 million decrease due to higher transmission expense; and
- an estimated $24 million decrease due to weather driven by a 19% decrease in heating degree days in 2015 and a 15% decrease in cooling degree days in the second quarter of 2015 partially offset by an 18% increase in cooling degree days in the third quarter of 2015.

The following table provides cooling degree days (CDD) and heating degree days (HDD) for the last three years at the Kansas City International Airport. CDD and HDD are used to reflect the demand for energy to cool or heat homes and buildings.

	2016	% Change	2015	% Change	2014
CDD	1,585	16	1,370	8	1,266
HDD	4,296	(6)	4,578	(19)	5,666

Electric Utility Other Operating Expenses *(including utility operating and maintenance expenses, general taxes and other)*

Electric utility's other operating expenses increased $50.0 million in 2016 compared to 2015 primarily driven by:

- a $4.8 million increase in pension expense corresponding to the resetting of pension expense trackers with the effective date of new retail rates;
- a $6.4 million increase in program costs for energy efficiency programs under MEEIA, which have a direct offset in revenue;
- a $4.9 million increase in plant operating and maintenance expense;
- a $7.9 million increase in injuries and damages expense primarily due to an increase in estimated losses from an unfavorable judgment in ongoing litigation; and
- a $13.7 million increase in general taxes driven by higher property taxes and higher gross receipts taxes due to an increase in retail revenues.

Electric utility's other operating expenses increased $33.8 million in 2015 compared to 2014 primarily driven by:

- a $22.2 million increase in program costs for energy efficiency programs under MEEIA, which have a direct offset in revenue, primarily due to the implementation of KCP&L's MEEIA programs in August 2014;
- a $7.2 million increase in amortization of deferred renewable energy costs under RESRAM, which have a direct offset in revenue;
- an $8.7 million increase in general taxes driven by higher property taxes; and
- a $10.0 million decrease in Wolf Creek operating and maintenance expenses primarily due to decreased refueling outage amortization of $3.6 million and $8.7 million from a planned mid-cycle maintenance outage in 2014.

Electric Utility Costs to Achieve the Anticipated Acquisition of Westar
Electric utility's costs to achieve the anticipated acquisition of Westar of $15.9 million in 2016 reflects consulting fees, certain severance expenses and other transition costs related to the anticipated acquisition of Westar.

Electric Utility Depreciation and Amortization
Electric utility's depreciation and amortization expense increased $14.4 million and $24.4 million in 2016 compared to 2015 and 2015 compared to 2014, respectively, due to capital additions.

Electric Utility Non-Operating Income and Expenses
Electric utility's non-operating income and expenses decreased $11.8 million in 2015 compared to 2014 primarily due to a $13.2 million decrease in the equity component of AFUDC primarily due to a lower average construction work in progress in 2015 due to environmental upgrades at KCP&L's La Cygne Station being placed into service.

Electric Utility Interest Charges
Electric utility's interest charges increased $5.2 million in 2016 compared to 2015 primarily due to a $7.9 million increase in interest expense related to KCP&L's issuance of $350 million of 3.65% Senior Notes in August 2015; partially offset by a $2.2 million decrease in interest expense due to KCP&L's purchase in lieu of redemption of its $50.0 million and $21.9 million EIRR Series 2005 bonds in September 2015.

Electric utility's interest charges increased $7.9 million in 2015 compared to 2014 primarily due to a $7.2 million decrease in in the equity component of AFUDC primarily due to a lower average construction work in progress in 2015 due to environmental upgrades at KCP&L's La Cygne Station being placed into service.

Electric Utility Income Tax Expense
Electric utility's income tax expense increased $43.5 million in 2016 compared to 2015 due to increased pre-tax income. Electric utility's income tax expense decreased $4.8 million in 2015 compared to 2014 primarily due to decreased pre-tax income.

GREAT PLAINS ENERGY SIGNIFICANT BALANCE SHEET CHANGES
(December 31, 2016 compared to December 31, 2015)

- Great Plains Energy's cash and cash equivalents increased $1,281.8 million due to a portion of the proceeds from Great Plains Energy's October 2016 common stock and depositary share offerings.
- Great Plains Energy's time deposit increased $1,000.0 million due to an investment made with a portion of the proceeds from Great Plains Energy's October 2016 common stock and depositary share offerings.
- Great Plains Energy's derivative instruments - current assets increased $80.7 million due to a $79.3 million mark-to-market gain on interest rate swaps entered into in June 2016 to hedge against interest rate fluctuations on future issuances of long-term debt expected to be issued to finance a portion of the cash consideration for the anticipated acquisition of Westar.

- Great Plains Energy's commercial paper increased $110.8 million due to an increase in commercial paper of $158.2 million at GMO due to borrowings for capital expenditures and general corporate purposes partially offset by the repayment of $47.4 million of commercial paper at KCP&L with funds from operations.
- Great Plains Energy's current maturities of long-term debt increased $381.0 million and long-term debt decreased $379.9 million due to the reclassification of KCP&L's $250.0 million of 5.85% Senior Notes and $31.0 million of 1.25% EIRR Series 1992 bonds and Great Plains Energy's $100.0 million of 6.875% Senior Notes from long-term to current.
- Great Plains Energy's deferred income taxes increased $170.9 million primarily due to an increase in temporary differences and changes in the projected utilization of net operating loss carryforwards, primarily driven by bonus depreciation.
- Great Plains Energy's asset retirement obligations increased $40.1 million primarily due to an increase in cost estimates for the closure of ponds and landfills containing coal combustion residuals (CCRs) at KCP&L electric generating facilities.
- Great Plains Energy's common stock increased $1,570.3 million primarily due to $1.55 billion in net proceeds from Great Plains Energy's public offering of 60.5 million shares of common stock in October 2016.
- Great Plains Energy's cumulative preferred stock $100 par value decreased $39.0 million due to the redemption of its 390,000 shares of outstanding cumulative preferred stock in August 2016.
- Great Plains Energy's preference stock without par value increased $836.2 million due to the issuance of Series B Preferred Stock in conjunction with Great Plains Energy's October 2016 depositary share offering. See Note 14 to the consolidated financial statements for additional information.

CAPITAL REQUIREMENTS AND LIQUIDITY

Great Plains Energy operates through its subsidiaries and has no material assets other than the stock of its subsidiaries and cash and cash equivalents and a time deposit to be used to fund a portion of the cash consideration for the anticipated acquisition of Westar. Great Plains Energy's ability to make payments on its debt securities and its ability to pay dividends is dependent on its receipt of dividends or other distributions from its subsidiaries, proceeds from the issuance of its securities and borrowing under its revolving credit facility.

Great Plains Energy's capital requirements are principally comprised of debt maturities and electric utility's construction and other capital expenditures. These items as well as additional cash and capital requirements, including the anticipated acquisition of Westar, are discussed below.

Great Plains Energy's liquid resources at December 31, 2016, consisted of $1.3 billion of cash and cash equivalents on hand, a $1.0 billion time deposit that matures in the first quarter of 2017 and $912.1 million of available borrowing capacity from unused bank lines of credit and receivable sale agreements. The available borrowing capacity consisted of $199.0 million from Great Plains Energy's revolving credit facility, $464.3 million from KCP&L's credit facilities and $248.8 million from GMO's credit facilities. See Notes 4 and 11 to the consolidated financial statements for more information regarding the receivable sale agreements and revolving credit facilities, respectively. Generally, Great Plains Energy uses these liquid resources to meet its day-to-day cash flow requirements, and from time to time issues equity and/or long-term debt to repay short-term debt or increase cash balances. However, the $1.3 billion of cash and cash equivalents on hand and the $1.0 billion time deposit at December 31, 2016, are primarily the result of Great Plains Energy's equity issuances in October 2016, the proceeds of which are to be used to fund a portion of the cash consideration for the anticipated acquisition of Westar.

Great Plains Energy intends to meet day-to-day cash flow requirements including interest payments, retirement of maturing debt, construction requirements, dividends and pension benefit plan funding requirements with a combination of internally generated funds and proceeds from short-term debt. From time to time, Great Plains Energy issues equity and/or long-term debt to repay short-term debt or increase cash balances. Great Plains

Energy's intention to meet a portion of these requirements with internally generated funds may be impacted by the effect of inflation on operating expenses, the level of MWh sales, regulatory actions, compliance with environmental regulations and the availability of generating units. In addition, Great Plains Energy may issue equity, equity-linked securities and/or debt to finance growth.

For a description of Great Plains Energy's financing activities and the remaining portion of its proposed financing plan with respect to the anticipated acquisition of Westar, see Note 2 to the consolidated financial statements.

Great Plains Energy also has a 364-day $5.1 billion senior unsecured bridge term loan facility to support the anticipated acquisition of Westar and provide flexibility for timing of long-term financing. See Note 11 to the consolidated financial statements for additional information.

Cash Flows from Operating Activities

Great Plains Energy generated positive cash flows from operating activities for the periods presented. The $30.9 million increase in cash flows from operating activities for Great Plains Energy in 2016 compared to 2015 was primarily driven by new retail rates for KCP&L and warmer weather. Other changes in working capital are detailed in Note 3 to the consolidated financial statements. The individual components of working capital vary with normal business cycles and operations.

The $54.9 million increase in cash flows from operating activities for Great Plains Energy in 2015 compared to 2014 was primarily due to a $34.2 million increase driven by a decrease in solar rebates paid to customers and an increase in the recovery of costs subject to fuel recovery mechanisms of $76.0 million, partially offset by a decrease in net income of $29.8 million and a decrease driven by deferred refueling outage costs of $23.7 million.

Cash Flows from Investing Activities

Great Plains Energy's cash used for investing activities varies with the timing of utility capital expenditures and purchases of investments and nonutility property. Investing activities are offset by proceeds from the sale of properties and insurance recoveries.

In 2016, Great Plains Energy purchased a time deposit of $1.0 billion with a portion of the proceeds from Great Plains Energy's October 2016 common stock and depositary share offerings.

Great Plains Energy's utility capital expenditures decreased $67.7 million in 2016 compared to 2015 primarily due to a decrease in cash utility capital expenditures related to infrastructure and system improvements.

Great Plains Energy's utility capital expenditures decreased $96.6 million in 2015 compared to 2014 primarily due to a decrease in cash utility capital expenditures related to environmental upgrades at KCP&L's La Cygne Station.

In January 2014, KCP&L and GMO completed the sale of two SPP-approved regional transmission projects, at cost, to Transource Missouri, LLC for cash proceeds of $37.7 million.

Cash Flows from Financing Activities

Great Plains Energy's cash flows from financing activities in 2016 reflect gross proceeds of $1.6 billion from the issuance of 60.5 million shares of common stock at a public offering price of $26.45 per share and gross proceeds of $862.5 million from the issuance of 17.3 million depositary shares each representing a 1/20th interest in a share of Great Plains Energy's Series B Preferred Stock at $50 per depositary share. Great Plains Energy paid $40.1 million for the redemption of its 390,000 shares of cumulative preferred stock and $143.6 million in issuance fees related to common stock and depositary share issuances, establishing Great Plains Energy's bridge term loan facility and a payment to OMERS pursuant to a stock purchase agreement.

Great Plains Energy's cash flows from financing activities in 2015 reflect KCP&L's issuance, at a discount, of $350.0 million of 3.65% Senior Notes that mature in 2025, with the proceeds used to purchase in lieu of redemption $71.9 million of EIRR bonds and repay short-term borrowings.

Great Plains Energy's cash flows from financing activities in 2014 reflect increased short-term borrowings at KCP&L primarily driven by capital expenditures and pension funding contributions.

Impact of Credit Ratings on Liquidity
The ratings of Great Plains Energy's, KCP&L's and GMO's securities by the credit rating agencies impact their liquidity, including the cost of borrowings under their revolving credit agreements and in the capital markets. After the announcement of the anticipated acquisition of Westar, Moody's Investors Service placed its long-term ratings of Great Plains Energy on review for downgrade and Standard & Poors' Ratings Services revised its outlook of Great Plains Energy, KCP&L and GMO from stable to negative. The Companies view maintenance of strong credit ratings as extremely important to their access to and cost of debt financing and to that end maintain an active and ongoing dialogue with the agencies with respect to results of operations, financial position and future prospects. While a decrease in these credit ratings would not cause any acceleration of Great Plains Energy's, KCP&L's or GMO's debt, it could increase interest charges under Great Plains Energy's 6.875% Senior Notes due 2017 or Great Plains Energy's, KCP&L's and GMO's revolving credit agreements. A decrease in credit ratings could also have, among other things, an adverse impact, which could be material, on Great Plains Energy's, KCP&L's and GMO's access to capital, the cost of funds, the ability to recover actual interest costs in state regulatory proceedings, the type and amounts of collateral required under supply agreements and Great Plains Energy's ability to provide credit support for its subsidiaries.

As of February 23, 2017, the major credit rating agencies rated Great Plains Energy's, KCP&L's and GMO's securities as detailed in the following table.

	Moody's Investors Service	Standard & Poor's
Great Plains Energy		
Outlook	Review for downgrade	Negative
Corporate Credit Rating	-	BBB+
Preferred Stock	Ba1	BBB-
Senior Unsecured Debt	Baa2	BBB
KCP&L		
Outlook	Stable	Negative
Senior Secured Debt	A2	A
Senior Unsecured Debt	Baa1	BBB+
Commercial Paper	P-2	A-2
GMO		
Outlook	Stable	Negative
Senior Unsecured Debt	Baa2	BBB+
Commercial Paper	P-2	A-2

A securities rating is not a recommendation to buy, sell or hold securities and may be subject to revision or withdrawal at any time by the assigning rating agency.

Financing Authorization
Under stipulations with MPSC and KCC, Great Plains Energy and KCP&L maintain common equity at not less than 30% and 35%, respectively, of total capitalization (including only the amount of short-term debt in excess of the amount of construction work in progress). KCP&L's long-term financing activities are subject to the authorization of the MPSC. On June 30, 2016, KCP&L's MPSC authorization to issue long-term debt expired. KCP&L will seek new authorization if and when it is deemed necessary.

KCP&L's and GMO's short-term financing activities are subject to the authorization of FERC. In November 2016, FERC authorized KCP&L to have outstanding at any one time up to a total of $1.0 billion in short-term debt instruments through December 2018. At December 31, 2016, there was $867.1 million available under this authorization. In February 2016, FERC authorized GMO to have outstanding at any one time up to a total of $750.0 million in short-term debt instruments through March 2018. At December 31, 2016, there was $548.1 million available under this authorization.

KCP&L and GMO are also authorized by FERC to participate in the Great Plains Energy money pool, an internal financing arrangement in which funds may be lent on a short-term basis to KCP&L and GMO. At December 31, 2016, there were no outstanding payables under the money pool.

Significant Financing Activities

Great Plains Energy

Great Plains Energy has an effective shelf registration statement for the sale of unlimited amounts of securities with the SEC that became effective in March 2015 and expires in March 2018. In September 2016, Great Plains Energy filed a post-effective amendment to its shelf registration statement to register depositary shares and preference stock among the types of securities that Great Plains Energy may offer and sell.

In October 2016, Great Plains Energy completed a registered public offering of 60.5 million shares of common stock, without par value, at a public offering price of $26.45 per share, for total gross proceeds of approximately $1.6 billion (net proceeds of approximately $1.55 billion after issuance costs). Great Plains Energy plans to use proceeds from the offering to fund a portion of the cash consideration for the anticipated acquisition of Westar.

In October 2016, Great Plains Energy also completed a registered public offering of 17.3 million depositary shares, each representing a 1/20th interest in a share of Great Plains Energy's Series B Preferred Stock, without par value, at a public offering price of $50 per depositary share for total gross proceeds of $862.5 million (net proceeds of approximately $836.2 million after issuance costs). Great Plains Energy plans to use proceeds from the offering to fund a portion of the cash consideration for the anticipated acquisition of Westar.

KCP&L

KCP&L has an effective shelf registration statement providing for the sale of unlimited amounts of notes and general mortgage bonds with the SEC that was filed and became effective in March 2015 and expires in March 2018.

In August 2015, KCP&L issued, at a discount, $350.0 million of 3.65% unsecured Senior Notes, maturing in 2025.

Debt Agreements

See Note 11 to the consolidated financial statements for information regarding revolving credit facilities and term loan facility related to the anticipated acquisition of Westar.

Projected Utility Capital Expenditures
Great Plains Energy's cash utility capital expenditures, excluding AFUDC to finance construction, were $609.4 million, $677.1 million and $773.7 million in 2016, 2015 and 2014, respectively. Utility capital expenditures represent a significant portion of Great Plains Energy's capital requirements. Utility capital expenditures projected for the next four years include improvements to generating, distribution and transmission facilities, software upgrades and expenditures for environmental projects at coal-fired power plants. Great Plains Energy intends to meet these capital requirements with a combination of internally generated funds and proceeds from short-term and long-term debt.

Utility capital expenditures projected for the next four years, excluding AFUDC, are detailed in the following table. This utility capital expenditure plan is subject to continual review and change.

	2017	2018	2019	2020
	(millions)			
Generating facilities	$ 180.5	$ 204.3	$ 178.0	$ 192.7
Distribution and transmission facilities	216.5	192.3	216.7	203.5
General facilities	106.2	98.5	56.7	69.4
Nuclear fuel	44.5	25.2	22.9	50.0
Environmental	43.4	36.6	11.5	14.0
Total utility capital expenditures	$ 591.1	$ 556.9	$ 485.8	$ 529.6

Pensions
The Company incurs significant costs in providing defined benefit plans for substantially all active and inactive employees of KCP&L and GMO and its 47% ownership share of WCNOC's defined benefit plans. Funding of the plans follows legal and regulatory requirements with funding equaling or exceeding the minimum requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA).

In 2016 and 2015, the Company contributed $69.8 million and $76.9 million to the pension plans, respectively, and expects to contribute $79.6 million in 2017 to satisfy ERISA funding requirements and the MPSC and KCC rate orders, the majority of which is expected to be paid by KCP&L. Additional contributions to the plans are expected beyond 2017 in amounts at least sufficient to meet the greater of ERISA or regulatory funding requirements; however, these amounts have not yet been determined.

Additionally, the Company provides post-retirement health and life insurance benefits for certain retired employees and expects to make benefit contributions of $4.6 million under the provisions of these plans in 2017, the majority of which is expected to be paid by KCP&L.

Management believes the Company has adequate access to capital resources through cash flows from operations or through existing lines of credit to support these funding requirements.

Supplemental Capital Requirements and Liquidity Information

The information in the following table is provided to summarize Great Plains Energy's cash obligations and commercial commitments.

Payment due by period	2017	2018	2019	2020	2021	After 2021	Total
Long-term debt				(millions)			
Principal	$ 382.1	$ 351.1	$ 401.1	$ 1.1	$ 432.0	$ 2,197.1	$ 3,764.5
Interest	182.5	156.8	131.3	116.9	108.3	945.9	1,641.7
Lease commitments							
Operating leases	12.9	11.0	9.3	9.7	9.7	110.5	163.1
Capital leases	0.4	0.4	0.4	0.4	0.4	3.1	5.1
Pension and other post-retirement plans	84.2	84.2	84.2	84.2	84.2	(a)	421.0
Purchase commitments							
Fuel	259.0	145.8	62.2	53.8	11.2	100.8	632.8
Power	47.3	47.3	47.3	47.3	47.4	462.2	698.8
Other	50.1	32.0	33.3	5.9	6.5	38.7	166.5
Total contractual commitments [a]	$ 1,018.5	$ 828.6	$ 769.1	$ 319.3	$ 699.7	$ 3,858.3	$ 7,493.5

[a] The Company expects to make contributions to the pension and other post-retirement plans beyond 2021 but the amounts are not yet determined. Amounts for years after 2017 are estimates based on information available in determining the amount for 2017. Actual amounts for years after 2017 could be significantly different than the estimated amounts in the table above.

Long-term debt includes current maturities. Long-term debt principal excludes $17.2 million of net discounts on senior notes and debt issuance costs. Variable rate interest obligations are based on rates as of December 31, 2016.

Lease commitments end in 2048. Operating lease commitments include railcars to serve jointly-owned generating units where KCP&L is the managing partner. Of the amounts included in the table above, KCP&L will be reimbursed by the other owners for approximately $1.5 million in 2017, $1.2 million in 2018 and approximately $0.4 million per year from 2019 to 2025, for a total of $5.5 million.

The Company expects to contribute $84.2 million to the pension and other post-retirement plans in 2017, of which the majority is expected to be paid by KCP&L. Additional contributions to the plans are expected beyond 2021 in amounts at least sufficient to meet the greater of ERISA or regulatory funding requirements; however, these amounts have not yet been determined. Amounts for years after 2017 are estimates based on information available in determining the amount for 2017. Actual amounts for years after 2017 could be significantly different than the estimated amounts in the table above.

Fuel commitments consist of commitments for nuclear fuel, coal and coal transportation costs. Power commitments consist of commitments for renewable energy under power purchase agreements. Other represents individual commitments entered into in the ordinary course of business.

Great Plains Energy has other insignificant long-term liabilities recorded on its consolidated balance sheet at December 31, 2016, which do not have a definitive cash payout date and are not included in the table above.

Off-Balance Sheet Arrangements

In the ordinary course of business, Great Plains Energy and certain of its subsidiaries enter into various agreements providing financial or performance assurance to third parties on behalf of certain subsidiaries. Such agreements include, for example, guarantees and letters of credit. These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to a subsidiary on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiary's intended business purposes. The majority of these agreements guarantee the Company's own future performance, so a liability for the fair value of the obligation is not recorded.

At December 31, 2016, Great Plains Energy has provided $135.3 million of credit support for GMO as follows:

- Great Plains Energy direct guarantees to GMO counterparties totaling $38.7 million, which expire in 2017 and 2018 and
- Great Plains Energy guarantees of GMO long-term debt totaling $96.6 million, which includes debt with maturity dates ranging from 2017 to 2023.

Great Plains Energy has also guaranteed GMO's commercial paper program. At December 31, 2016, GMO had $201.9 million commercial paper outstanding. None of the guaranteed obligations are subject to default or prepayment if GMO's credit ratings were downgraded.

At December 31, 2016, KCP&L had issued letters of credit totaling $8.8 million as credit support to certain counterparties that expire in 2017. KCP&L has issued $148.1 million of letters of credit as credit support for its variable rate EIRR Bond Series 2007A and B that expire in 2018.

At December 31, 2016, GMO had issued letters of credit totaling $1.9 million as credit support to certain counterparties that expire in 2017.

KANSAS CITY POWER & LIGHT COMPANY

MANAGEMENT'S NARRATIVE ANALYSIS OF RESULTS OF OPERATIONS

The following table summarizes KCP&L's consolidated comparative results of operations.

	2016	2015
	(millions)	
Operating revenues	$ 1,875.4	$ 1,713.8
Fuel and purchased power	(372.7)	(397.1)
Transmission	(56.4)	(58.4)
Other operating expenses	(705.8)	(658.6)
Costs to achieve the anticipated acquisition of Westar	(10.9)	—
Depreciation and amortization	(247.5)	(235.7)
Operating income	482.1	364.0
Non-operating income and expenses	4.2	1.2
Interest charges	(139.4)	(135.6)
Income tax expense	(121.9)	(76.8)
Net income	$ 225.0	$ 152.8
Reconciliation of gross margin to operating revenue:		
Operating revenues	$ 1,875.4	$ 1,713.8
Fuel and purchased power	(372.7)	(397.1)
Transmission	(56.4)	(58.4)
Gross margin [a]	$ 1,446.3	$ 1,258.3

[a] Gross margin is a non-GAAP financial measure. See explanation of gross margin under Great Plains Energy's Results of Operations.

KCP&L Gross Margin and MWh Sales
The following table summarizes KCP&L's gross margin and MWhs sold.

	Revenues and Costs		%	MWhs Sold		%
	2016	2015	Change[c]	2016	2015	Change
Retail revenues	(millions)			(thousands)		
Residential	$ 713.0	$ 639.9	11	5,330	5,213	2
Commercial	798.5	738.7	8	7,553	7,569	—
Industrial	147.4	137.8	7	1,839	1,833	—
Other retail revenues	13.1	12.5	6	83	83	—
Provision for rate refund	0.8	—	N/M	N/A	N/A	N/A
Energy efficiency (MEEIA)[a]	50.9	27.5	85	N/A	N/A	N/A
Total retail	1,723.7	1,556.4	11	14,805	14,698	1
Wholesale revenues	128.9	134.1	(4)	6,629	6,099	9
Other revenues	22.8	23.3	(2)	N/A	N/A	N/A
Operating revenues	1,875.4	1,713.8	9	21,434	20,797	3
Fuel and purchased power	(372.7)	(397.1)	(6)			
Transmission	(56.4)	(58.4)	(3)			
Gross margin [b]	$ 1,446.3	$ 1,258.3	15			

[a] Consists of recovery of program costs of $31.0 million and $20.5 million for 2016 and 2015, respectively, that have a direct offset in operating and maintenance expenses, recovery of throughput disincentive of $9.5 million and $7.0 million for 2016 and 2015, respectively, and a performance incentive of $10.4 million for 2016.
[b] Gross margin is a non-GAAP financial measure. See explanation of gross margin under Great Plains Energy's Results of Operations.
[c] N/M - not meaningful

KCP&L's gross margin increased $188.0 million in 2016 compared to 2015 primarily driven by:

- an estimated $111 million increase due to new retail rates and an estimated $37 million increase due to new cost recovery mechanisms for KCP&L in Missouri effective September 29, 2015, and in Kansas effective October 1, 2015;
- an estimated $25 million increase due to warmer weather with a 16% increase in cooling degree days in 2016;
- a $10.5 million increase for recovery of program costs for energy efficiency programs under MEEIA, which have a direct offset in operating and maintenance expense;
- a $2.5 million increase in MEEIA throughput disincentive;
- a $10.4 million MEEIA performance incentive recognized in 2016 related to the achievement of certain energy savings levels in the first cycle of KCP&L's MEEIA programs; and
- an estimated $6 million decrease due to a decrease in weather-normalized retail demand.

KCP&L Other Operating Expenses *(including operating and maintenance expenses, general taxes and other)*
KCP&L's other operating expenses increased $47.2 million in 2016 compared to 2015 primarily driven by:

- a $5.6 million increase in pension expense corresponding to the resetting of pension expense trackers with the effective date of new retail rates;
- a $10.5 million increase in program costs for energy efficiency programs under MEEIA, which have a direct offset in revenue;
- a $2.3 million increase in plant operating and maintenance expense;
- a $7.4 million increase in injuries and damages expense primarily due to an increase in estimated losses from an unfavorable judgment in ongoing litigation; and

- a $14.0 million increase in general taxes driven by higher property taxes and higher gross receipts taxes due to an increase in retail revenues.

KCP&L Costs to Achieve the Anticipated Acquisition of Westar
KCP&L's costs to achieve the anticipated acquisition of Westar of $10.9 million in 2016 reflects consulting fees, certain severance expenses and other transition costs related to the anticipated acquisition of Westar.

KCP&L Depreciation and Amortization
KCP&L's depreciation and amortization expense increased $11.8 million in 2016 compared to 2015 due to capital additions.

KCP&L Interest Charges
KCP&L's interest charges increased $3.8 million in 2016 compared to 2015 primarily due to a $7.9 million increase in interest expense related to KCP&L's issuance of $350 million of 3.65% Senior Notes in August 2015; partially offset by a $2.2 million decrease in interest expense due to KCP&L's purchase in lieu of redemption of its $50.0 million and $21.9 million EIRR Series 2005 bonds in September 2015.

KCP&L Income Tax Expense
KCP&L's income tax expense increased $45.1 million in 2016 compared to 2015 due to increased pre-tax income.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

In the ordinary course of business, Great Plains Energy and KCP&L face risks that are either non-financial or non-quantifiable. Such risks principally include business, legal, operational and credit risks and are not represented in the following analysis. See Item 1A Risk Factors and Item 7 MD&A for further discussion of risk factors.

Great Plains Energy and KCP&L are exposed to market risks associated with commodity price and supply, interest rates and equity prices. Management has established risk management policies and strategies to reduce the potentially adverse effects that the volatility of the markets may have on its operating results. During the ordinary course of business, under the direction and control of an internal commodity risk committee, Great Plains Energy's and KCP&L's hedging strategies are reviewed to determine the hedging approach deemed appropriate based upon the circumstances of each situation. Though management believes its risk management practices are effective, it is not possible to identify and eliminate all risk. Great Plains Energy and KCP&L could experience losses, which could have a material adverse effect on their results of operations or financial position, due to many factors, including unexpectedly large or rapid movements or disruptions in the energy markets, from regulatory-driven market rule changes and/or bankruptcy or non-performance of customers or counterparties, and/or failure of underlying transactions that have been hedged to materialize.

Hedging Strategies

Derivative instruments are utilized to execute risk management and hedging strategies. Derivative instruments, such as futures, forward contracts, swaps or options, derive their value from underlying assets, indices, reference rates or a combination of these factors. These derivative instruments include negotiated contracts, which are referred to as over-the-counter derivatives, and instruments listed and traded on an exchange.

Interest Rate Risk

Great Plains Energy and KCP&L manage interest expense and short- and long-term liquidity through a combination of fixed and variable rate debt. Generally, the amount of each type of debt is managed through market issuance, but interest rate swap and cap agreements with highly rated financial institutions may also be used to achieve the desired combination. At December 31, 2016, 4% and 6%, respectively, of Great Plains Energy's and KCP&L's long-term debt was variable rate debt. Interest rates impact the fair value of long-term debt. A change in interest rates would impact Great Plains Energy and KCP&L to the extent they redeemed any of their outstanding long-term debt. Great Plains Energy's and KCP&L's book values of long-term debt were below fair value by 5% at December 31, 2016.

Great Plains Energy and KCP&L had $334.8 million and $132.9 million, respectively, of commercial paper outstanding at December 31, 2016. The principal amount of the commercial paper, which will vary during the year, drives Great Plains Energy's and KCP&L's commercial paper interest expense. Assuming $334.8 million and $132.9 million of commercial paper was outstanding for all of 2017 for Great Plains Energy and KCP&L, respectively, a hypothetical 10% increase in commercial paper rates would result in an increase in interest expense of $0.3 million for Great Plains Energy and $0.1 million for KCP&L in 2017. Assuming $334.8 million and $132.9 million of commercial paper was outstanding for all of 2017 for Great Plains Energy and KCP&L, respectively, a hypothetical 100 basis point increase in commercial paper rates would result in an increase in interest expense of $3.3 million for Great Plains Energy and $1.3 million for KCP&L in 2017.

At December 31, 2016, Great Plains Energy had $4.4 billion of notional amounts of fixed-to-floating interest rate swaps to hedge against interest rate fluctuations on future issuances of long-term debt expected to be issued to finance a portion of the cash consideration for the anticipated acquisition of Westar. Settlement of these swaps is contingent on the consummation of the anticipated acquisition of Westar. Assuming settlement of the swaps, a hypothetical 10% decrease in the interest rates underlying the swaps would have resulted in an approximately $51 million increase in interest expense associated with settlement of the swaps as of December 31, 2016.

Commodity Risk
Great Plains Energy and KCP&L engage in the wholesale and retail marketing of electricity and are exposed to risk associated with the price of electricity. Exposure to these risks is affected by a number of factors including the quantity and availability of fuel used for generation and the quantity of electricity customers consume. Customers' electricity usage could also vary from year to year based on the weather or other factors. Quantities of fossil fuel used for generation vary from year to year based on the availability, price and deliverability of a given fuel type as well as planned and unplanned outages at facilities that use fossil fuels.

KCP&L's wholesale operations include the physical delivery and marketing of power obtained through its generation capacity. KCP&L is required to maintain a capacity margin of at least 12%. This net positive supply of capacity and energy is maintained through KCP&L's generation assets and capacity and power purchase agreements to protect KCP&L from the potential operational failure of one of its power generating units. KCP&L continually evaluates the need for additional risk mitigation measures in order to minimize its financial exposure to, among other things, spikes in wholesale power prices during periods of high demand.

KCP&L's sales include the sale of electricity to its retail customers and bulk power sales of electricity in the wholesale market. KCP&L is a member of SPP Consolidated Balancing Authority (CBA) and Integrated Marketplace (IM), which are largely responsible for the dispatch of member generating facilities and the resulting supply of energy to fulfill member load obligations. KCP&L's Kansas ECA allows for the recovery of increased fuel and purchased power costs from Kansas retail customers. KCP&L's Missouri FAC allows for KCP&L Missouri retail electric rates to be adjusted based on 95% of the difference between actual fuel and purchased power costs and the amount of fuel and purchased power costs provided in base rates. Most of the change in market prices for fuel and purchased power is recovered through the ECA or FAC, which mitigates KCP&L's commodity price exposure.

GMO is also a member of SPP's CBA and IM. GMO has an FAC that allows GMO to adjust retail electric rates based on 95% of the difference between actual fuel and purchased power costs and the amount of fuel and purchased power costs provided in base rates. Most of the change in market prices for fuel and purchased power is recovered through the FAC, which mitigates GMO's commodity price exposure.

Credit Risk - MPS Merchant
MPS Merchant is exposed to credit risk. Credit risk is measured by the loss that would be recorded if counterparties failed to perform pursuant to the terms of the contractual obligations less the value of any collateral held. MPS Merchant's counterparties are not externally rated. Credit exposure to counterparties at December 31, 2016, was $8.7 million.

Investment Risk
KCP&L maintains trust funds, as required by the NRC, to fund its share of decommissioning the Wolf Creek nuclear power plant. As of December 31, 2016, these funds were invested primarily in domestic equity securities and fixed income securities and are reflected at fair value on KCP&L's balance sheets. The mix of securities is designed to provide returns to be used to fund decommissioning and to compensate for inflationary increases in decommissioning costs; however, the equity securities in the trusts are exposed to price fluctuations in equity markets and the value of fixed rate fixed income securities are exposed to changes in interest rates. A hypothetical increase in interest rates resulting in a hypothetical 10% decrease in the value of the fixed income securities would have resulted in a $6.5 million reduction in the value of the decommissioning trust funds at December 31, 2016. A hypothetical 10% decrease in equity prices would have resulted in a $15.2 million reduction in the fair value of the equity securities at December 31, 2016. KCP&L's exposure to investment risk associated with the decommissioning trust funds is in large part mitigated due to the fact that KCP&L is currently allowed to recover its decommissioning costs in its rates. If the actual return on trust assets is below the anticipated level, KCP&L could be responsible for the balance of funds required to decommission Wolf Creek; however, while there can be no assurances, management believes a rate increase would be allowed to recover decommissioning costs over the remaining life of the unit.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
Great Plains Energy Incorporated
Kansas City, Missouri

We have audited the accompanying consolidated balance sheets of Great Plains Energy Incorporated and subsidiaries (the "Company") as of December 31, 2016 and 2015, and the related consolidated statements of comprehensive income, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2016. Our audits also included the financial statement schedules listed in the Index at Item 15. These financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedules based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Great Plains Energy Incorporated and subsidiaries as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2016, based on the criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 23, 2017, expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/DELOITTE & TOUCHE LLP

Kansas City, Missouri
February 23, 2017

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Kansas City Power & Light Company
Kansas City, Missouri

We have audited the accompanying consolidated balance sheets of Kansas City Power & Light Company and subsidiaries (the "Company") as of December 31, 2016 and 2015, and the related consolidated statements of comprehensive income, common shareholder's equity, and cash flows for each of the three years in the period ended December 31, 2016. Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Kansas City Power & Light Company and subsidiaries as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2016, based on the criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 23, 2017, expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/DELOITTE & TOUCHE LLP

Kansas City, Missouri
February 23, 2017

GREAT PLAINS ENERGY INCORPORATED

Consolidated Statements of Comprehensive Income

Year Ended December 31	**2016**	2015	2014
Operating Revenues	(millions, except per share amounts)		
Electric revenues	**$ 2,676.0**	$ 2,502.2	$ 2,568.2
Operating Expenses			
Fuel and purchased power	**590.1**	608.7	742.5
Transmission	**84.8**	89.1	74.7
Utility operating and maintenance expenses	**759.5**	724.8	701.9
Costs to achieve the anticipated acquisition of Westar Energy, Inc.	**34.2**	—	—
Depreciation and amortization	**344.8**	330.4	306.0
General taxes	**226.7**	213.2	204.6
Other	**17.0**	5.9	4.0
Total	**2,057.1**	1,972.1	2,033.7
Operating income	**618.9**	530.1	534.5
Non-operating income	**17.1**	11.7	25.0
Non-operating expenses	**(14.3)**	(8.0)	(12.5)
Interest charges	**(161.5)**	(199.3)	(188.5)
Income before income tax expense and income from equity investments	**460.2**	334.5	358.5
Income tax expense	**(172.2)**	(122.7)	(115.7)
Income from equity investments, net of income taxes	**2.0**	1.2	—
Net income	**290.0**	213.0	242.8
Preferred stock dividend requirements and redemption premium	**16.5**	1.6	1.6
Earnings available for common shareholders	**$ 273.5**	$ 211.4	$ 241.2
Average number of basic common shares outstanding	**169.4**	154.2	153.9
Average number of diluted common shares outstanding	**169.8**	154.8	154.1
Basic and diluted earnings per common share	**$ 1.61**	$ 1.37	$ 1.57
Comprehensive Income			
Net income	**$ 290.0**	$ 213.0	$ 242.8
Other comprehensive income			
Derivative hedging activity			
Reclassification to expenses, net of tax	**5.6**	5.7	8.0
Derivative hedging activity, net of tax	**5.6**	5.7	8.0
Defined benefit pension plans			
Net gain (loss) arising during period	**(1.1)**	1.0	(3.0)
Income tax (expense) benefit	**0.4**	(0.4)	1.2
Net gain (loss) arising during period, net of tax	**(0.7)**	0.6	(1.8)
Amortization of net losses included in net periodic benefit costs, net of tax	**0.5**	0.4	0.4
Change in unrecognized pension expense, net of tax	**(0.2)**	1.0	(1.4)
Total other comprehensive income	**5.4**	6.7	6.6
Comprehensive income	**$ 295.4**	$ 219.7	$ 249.4

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

GREAT PLAINS ENERGY INCORPORATED

Consolidated Balance Sheets

	December 31	
	2016	2015
ASSETS	(millions, except share amounts)	
Current Assets		
Cash and cash equivalents	**$ 1,293.1**	$ 11.3
Time deposit	**1,000.0**	—
Receivables, net	**166.0**	147.7
Accounts receivable pledged as collateral	**172.4**	175.0
Fuel inventories, at average cost	**108.8**	118.4
Materials and supplies, at average cost	**162.2**	155.7
Deferred refueling outage costs	**22.3**	19.2
Refundable income taxes	**—**	3.8
Derivative instruments	**81.5**	0.8
Prepaid expenses and other assets	**53.2**	32.3
Total	**3,059.5**	664.2
Utility Plant, at Original Cost		
Electric	**13,597.7**	13,189.9
Less - accumulated depreciation	**5,106.9**	4,943.7
Net utility plant in service	**8,490.8**	8,246.2
Construction work in progress	**403.9**	347.9
Nuclear fuel, net of amortization of $172.1 and $192.5	**62.0**	68.3
Total	**8,956.7**	8,662.4
Investments and Other Assets		
Nuclear decommissioning trust fund	**222.9**	200.7
Regulatory assets	**1,048.0**	979.1
Goodwill	**169.0**	169.0
Other	**113.9**	63.2
Total	**1,553.8**	1,412.0
Total	**$ 13,570.0**	$ 10,738.6

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

GREAT PLAINS ENERGY INCORPORATED

Consolidated Balance Sheets

	December 31 2016	December 31 2015
LIABILITIES AND CAPITALIZATION	(millions, except share amounts)	
Current Liabilities		
Notes payable	**$ —**	$ 10.0
Collateralized note payable	**172.4**	175.0
Commercial paper	**334.8**	224.0
Current maturities of long-term debt	**382.1**	1.1
Accounts payable	**323.7**	352.9
Accrued taxes	**33.3**	31.6
Accrued interest	**50.8**	44.7
Accrued compensation and benefits	**52.1**	41.4
Pension and post-retirement liability	**3.0**	3.4
Other	**32.6**	31.6
Total	**1,384.8**	915.7
Deferred Credits and Other Liabilities		
Deferred income taxes	**1,329.7**	1,158.8
Deferred tax credits	**126.2**	125.1
Asset retirement obligations	**316.0**	275.9
Pension and post-retirement liability	**488.3**	455.2
Regulatory liabilities	**309.9**	284.4
Other	**87.9**	82.9
Total	**2,658.0**	2,382.3
Capitalization		
Great Plains Energy shareholders' equity		
Common stock - 600,000,000 and 250,000,000 shares authorized without par value 215,479,105 and 154,504,900 shares issued, stated value	**4,217.0**	2,646.7
Cumulative preferred stock - 390,000 shares authorized, $100 par value 0 and 390,000 shares issued and outstanding	**—**	39.0
Preference stock - 11,000,000 shares authorized without par value 7.00% Series B Mandatory Convertible Preferred Stock $1,000 per share liquidation preference, 862,500 and 0 shares issued and outstanding	**836.2**	—
Retained earnings	**1,119.2**	1,024.4
Treasury stock - 128,087 and 101,229 shares, at cost	**(3.8)**	(2.6)
Accumulated other comprehensive loss	**(6.6)**	(12.0)
Total shareholders' equity	**6,162.0**	3,695.5
Long-term debt (Note 12)	**3,365.2**	3,745.1
Total	**9,527.2**	7,440.6
Commitments and Contingencies (Note 15)		
Total	**$ 13,570.0**	$ 10,738.6

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

GREAT PLAINS ENERGY INCORPORATED

Consolidated Statements of Cash Flows

Year Ended December 31	2016	2015	2014
Cash Flows from Operating Activities		(millions)	
Net income	**$ 290.0**	$ 213.0	$ 242.8
Adjustments to reconcile income to net cash from operating activities:			
Depreciation and amortization	**344.8**	330.4	306.0
Amortization of:			
Nuclear fuel	**26.6**	26.8	26.1
Other	**77.5**	47.7	46.1
Deferred income taxes, net	**170.1**	124.9	125.8
Investment tax credit amortization	**(1.4)**	(1.4)	(1.4)
Income from equity investments, net of income taxes	**(2.0)**	(1.2)	—
Fair value impacts of interest rate swaps	**(79.3)**	—	—
Other operating activities (Note 3)	**(42.3)**	12.9	(47.2)
Net cash from operating activities	**784.0**	753.1	698.2
Cash Flows from Investing Activities			
Utility capital expenditures	**(609.4)**	(677.1)	(773.7)
Allowance for borrowed funds used during construction	**(6.8)**	(5.8)	(13.0)
Purchases of nuclear decommissioning trust investments	**(31.9)**	(50.9)	(27.5)
Proceeds from nuclear decommissioning trust investments	**28.6**	47.6	24.2
Purchase of time deposit	**(1,000.0)**	—	—
Proceeds from sale of transmission assets	**—**	—	37.7
Other investing activities	**(64.0)**	(48.2)	(27.5)
Net cash from investing activities	**(1,683.5)**	(734.4)	(779.8)
Cash Flows from Financing Activities			
Issuance of common stock	**1,603.7**	3.0	4.8
Issuance of preference stock	**862.5**	—	—
Issuance of long-term debt	**—**	348.8	—
Issuance of long-term debt from remarketing	**—**	146.5	—
Repayment of long-term debt from remarketing	**—**	(146.5)	—
Issuance fees	**(143.6)**	(3.0)	(0.9)
Repayment of long-term debt	**(1.1)**	(87.0)	(13.4)
Net change in short-term borrowings	**100.8**	(128.3)	245.1
Net change in collateralized short-term borrowings	**(2.6)**	4.0	(4.0)
Dividends paid	**(194.0)**	(155.5)	(145.6)
Redemption of cumulative preferred stock	**(40.1)**	—	—
Purchase of treasury stock	**(5.0)**	(1.6)	(2.5)
Other financing activities	**0.7**	(0.8)	0.5
Net cash from financing activities	**2,181.3**	(20.4)	84.0
Net Change in Cash and Cash Equivalents	**1,281.8**	(1.7)	2.4
Cash and Cash Equivalents at Beginning of Year	**11.3**	13.0	10.6
Cash and Cash Equivalents at End of Year	**$ 1,293.1**	$ 11.3	$ 13.0

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

GREAT PLAINS ENERGY INCORPORATED

Consolidated Statements of Shareholders' Equity

Year Ended December 31	**2016**		2015		2014	
	Shares	**Amount**	Shares	Amount	Shares	Amount
Common Stock			(millions, except share amounts)			
Beginning balance	**154,504,900**	**$ 2,646.7**	154,254,037	$ 2,639.3	153,995,621	$ 2,631.1
Issuance of common stock	**60,974,205**	**1,565.3**	250,863	6.6	258,416	6.7
Equity compensation expense, net of forfeitures		**4.3**		1.9		0.5
Unearned Compensation						
Issuance of restricted common stock		**(2.8)**		(2.4)		(2.1)
Forfeiture of restricted common stock		**—**		0.5		—
Compensation expense recognized		**2.7**		1.8		2.0
Other		**0.8**		(1.0)		1.1
Ending balance	**215,479,105**	**4,217.0**	154,504,900	2,646.7	154,254,037	2,639.3
Cumulative Preferred Stock						
Beginning balance	**390,000**	**39.0**	390,000	39.0	390,000	39.0
Redemption of cumulative preferred stock	**(390,000)**	**(39.0)**	—	—	—	—
Ending balance	**—**	**—**	390,000	39.0	390,000	39.0
Preference Stock						
Beginning balance	**—**	**—**	—	—	—	—
Issuance of Series B Mandatory Convertible Preferred Stock	**862,500**	**836.2**	—	—	—	—
Ending balance	**862,500**	**836.2**	—	—	—	—
Retained Earnings						
Beginning balance		**1,024.4**		967.8		871.4
Net income		**290.0**		213.0		242.8
Redemption premium on cumulative preferred stock		**(0.6)**		—		—
Dividends:						
Common stock ($1.0625, $0.9975 and $0.935 per share)		**(181.0)**		(153.9)		(144.0)
Preferred stock - at required rates		**(13.0)**		(1.6)		(1.6)
Performance shares		**(0.6)**		(0.9)		(0.8)
Ending balance		**1,119.2**		1,024.4		967.8
Treasury Stock						
Beginning balance	**(101,229)**	**(2.6)**	(91,281)	(2.3)	(129,290)	(2.8)
Treasury shares acquired	**(138,021)**	**(4.1)**	(76,468)	(2.0)	(85,744)	(2.2)
Treasury shares reissued	**111,163**	**2.9**	66,520	1.7	123,753	2.7
Ending balance	**(128,087)**	**(3.8)**	(101,229)	(2.6)	(91,281)	(2.3)
Accumulated Other Comprehensive Income (Loss)						
Beginning balance		**(12.0)**		(18.7)		(25.3)
Derivative hedging activity, net of tax		**5.6**		5.7		8.0
Change in unrecognized pension expense, net of tax		**(0.2)**		1.0		(1.4)
Ending balance		**(6.6)**		(12.0)		(18.7)
Total Great Plains Energy Shareholders' Equity		**$ 6,162.0**		$ 3,695.5		$ 3,625.1

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

KANSAS CITY POWER & LIGHT COMPANY

Consolidated Statements of Comprehensive Income

Year Ended December 31	2016	2015	2014
Operating Revenues		(millions)	
Electric revenues	**$ 1,875.4**	$ 1,713.8	$ 1,730.8
Operating Expenses			
Fuel and purchased power	**372.7**	397.1	472.7
Transmission	**56.4**	58.4	47.2
Operating and maintenance expenses	**525.8**	494.2	489.1
Costs to achieve the anticipated acquisition of Westar Energy, Inc.	**10.9**	—	—
Depreciation and amortization	**247.5**	235.7	213.9
General taxes	**177.5**	163.5	159.1
Other	**2.5**	0.9	(1.3)
Total	**1,393.3**	1,349.8	1,380.7
Operating income	**482.1**	364.0	350.1
Non-operating income	**11.8**	8.4	20.4
Non-operating expenses	**(7.6)**	(7.2)	(8.3)
Interest charges	**(139.4)**	(135.6)	(124.1)
Income before income tax expense	**346.9**	229.6	238.1
Income tax expense	**(121.9)**	(76.8)	(75.7)
Net income	**$ 225.0**	$ 152.8	$ 162.4
Comprehensive Income			
Net income	**$ 225.0**	$ 152.8	$ 162.4
Other comprehensive income			
Derivative hedging activity			
Reclassification to expenses, net of tax	**5.4**	5.3	5.3
Derivative hedging activity, net of tax	**5.4**	5.3	5.3
Total other comprehensive income	**5.4**	5.3	5.3
Comprehensive income	**$ 230.4**	$ 158.1	$ 167.7

The disclosures regarding KCP&L included in the accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

KANSAS CITY POWER & LIGHT COMPANY

Consolidated Balance Sheets

	December 31	
	2016	2015
ASSETS	(millions, except share amounts)	
Current Assets		
Cash and cash equivalents	**$ 4.5**	$ 2.3
Receivables, net	**139.1**	129.2
Related party receivables	**67.2**	65.8
Accounts receivable pledged as collateral	**110.0**	110.0
Fuel inventories, at average cost	**72.9**	83.5
Materials and supplies, at average cost	**118.9**	114.6
Deferred refueling outage costs	**22.3**	19.2
Refundable income taxes	**12.7**	79.0
Prepaid expenses and other assets	**27.9**	27.6
Total	**575.5**	631.2
Utility Plant, at Original Cost		
Electric	**9,925.1**	9,640.4
Less - accumulated depreciation	**3,858.4**	3,722.6
Net utility plant in service	**6,066.7**	5,917.8
Construction work in progress	**300.4**	246.6
Nuclear fuel, net of amortization of $172.1 and $192.5	**62.0**	68.3
Total	**6,429.1**	6,232.7
Investments and Other Assets		
Nuclear decommissioning trust fund	**222.9**	200.7
Regulatory assets	**801.8**	732.4
Other	**29.1**	17.6
Total	**1,053.8**	950.7
Total	**$ 8,058.4**	$ 7,814.6

The disclosures regarding KCP&L included in the accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

KANSAS CITY POWER & LIGHT COMPANY

Consolidated Balance Sheets

	December 31	
	2016	2015
LIABILITIES AND CAPITALIZATION	(millions, except share amounts)	
Current Liabilities		
Collateralized note payable	**$ 110.0**	$ 110.0
Commercial paper	**132.9**	180.3
Current maturities of long-term debt	**281.0**	—
Accounts payable	**231.6**	258.8
Accrued taxes	**27.0**	25.6
Accrued interest	**32.4**	32.4
Accrued compensation and benefits	**52.1**	41.4
Pension and post-retirement liability	**1.6**	2.0
Other	**11.4**	12.6
Total	**880.0**	663.1
Deferred Credits and Other Liabilities		
Deferred income taxes	**1,228.3**	1,132.6
Deferred tax credits	**122.8**	123.8
Asset retirement obligations	**278.0**	239.3
Pension and post-retirement liability	**465.8**	433.4
Regulatory liabilities	**187.4**	164.6
Other	**70.6**	61.6
Total	**2,352.9**	2,155.3
Capitalization		
Common shareholder's equity		
Common stock - 1,000 shares authorized without par value		
1 share issued, stated value	**1,563.1**	1,563.1
Retained earnings	**982.6**	879.6
Accumulated other comprehensive loss	**(4.2)**	(9.6)
Total	**2,541.5**	2,433.1
Long-term debt (Note 12)	**2,284.0**	2,563.1
Total	**4,825.5**	4,996.2
Commitments and Contingencies (Note 15)		
Total	**$ 8,058.4**	$ 7,814.6

The disclosures regarding KCP&L included in the accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

KANSAS CITY POWER & LIGHT COMPANY

Consolidated Statements of Cash Flows

Year Ended December 31	**2016**	2015	2014
Cash Flows from Operating Activities		(millions)	
Net income	**$ 225.0**	$ 152.8	$ 162.4
Adjustments to reconcile income to net cash from operating activities:			
Depreciation and amortization	**247.5**	235.7	213.9
Amortization of:			
Nuclear fuel	**26.6**	26.8	26.1
Other	**33.9**	29.1	29.3
Deferred income taxes, net	**93.4**	99.4	88.4
Investment tax credit amortization	**(1.0)**	(1.0)	(1.0)
Other operating activities (Note 3)	**(2.1)**	(61.5)	(64.7)
Net cash from operating activities	**623.3**	481.3	454.4
Cash Flows from Investing Activities			
Utility capital expenditures	**(418.8)**	(518.3)	(635.9)
Allowance for borrowed funds used during construction	**(5.6)**	(3.9)	(11.1)
Purchases of nuclear decommissioning trust investments	**(31.9)**	(50.9)	(27.5)
Proceeds from nuclear decommissioning trust investments	**28.6**	47.6	24.2
Net money pool lending	**—**	—	4.7
Other investing activities	**(23.8)**	(25.5)	(15.2)
Net cash from investing activities	**(451.5)**	(551.0)	(660.8)
Cash Flows from Financing Activities			
Issuance of long-term debt	**—**	348.8	—
Issuance fees	**(0.2)**	(3.0)	(0.4)
Issuance of long-term debt from remarketing	**—**	146.5	—
Repayment of long-term debt from remarketing	**—**	(146.5)	—
Repayment of long-term debt	**—**	(85.9)	—
Net change in short-term borrowings	**(47.4)**	(178.0)	265.1
Net money pool borrowings	**—**	(12.6)	12.4
Dividends paid to Great Plains Energy	**(122.0)**	—	(72.0)
Net cash from financing activities	**(169.6)**	69.3	205.1
Net Change in Cash and Cash Equivalents	**2.2**	(0.4)	(1.3)
Cash and Cash Equivalents at Beginning of Year	**2.3**	2.7	4.0
Cash and Cash Equivalents at End of Year	**$ 4.5**	$ 2.3	$ 2.7

The disclosures regarding KCP&L included in the accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

KANSAS CITY POWER & LIGHT COMPANY

Consolidated Statements of Common Shareholder's Equity

Year Ended December 31	**2016**		2015		2014	
	Shares	**Amount**	Shares	Amount	Shares	Amount
			(millions, except share amounts)			
Common Stock	**1**	**$ 1,563.1**	1	$ 1,563.1	1	$ 1,563.1
Retained Earnings						
Beginning balance		**879.6**		726.8		636.4
Net income		**225.0**		152.8		162.4
Dividends:						
Common stock held by Great Plains Energy		**(122.0)**		—		(72.0)
Ending balance		**982.6**		879.6		726.8
Accumulated Other Comprehensive Income (Loss)						
Beginning balance		**(9.6)**		(14.9)		(20.2)
Derivative hedging activity, net of tax		**5.4**		5.3		5.3
Ending balance		**(4.2)**		(9.6)		(14.9)
Total Common Shareholder's Equity		**$ 2,541.5**		$ 2,433.1		$ 2,275.0

The disclosures regarding KCP&L included in the accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

Notes to Consolidated Financial Statements

The notes to consolidated financial statements that follow are a combined presentation for Great Plains Energy Incorporated and Kansas City Power & Light Company, both registrants under this filing. The terms "Great Plains Energy," "Company," "KCP&L" and "Companies" are used throughout this report. "Great Plains Energy" and the "Company" refer to Great Plains Energy Incorporated and its consolidated subsidiaries, unless otherwise indicated. "KCP&L" refers to Kansas City Power & Light Company and its consolidated subsidiaries. "Companies" refers to Great Plains Energy Incorporated and its consolidated subsidiaries and KCP&L and its consolidated subsidiaries.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization
Great Plains Energy, a Missouri corporation incorporated in 2001, is a public utility holding company and does not own or operate any significant assets other than the stock of its subsidiaries and cash and cash equivalents and a time deposit to be used to fund a portion of the cash consideration for the anticipated acquisition of Westar Energy, Inc. (Westar). Great Plains Energy's wholly owned direct subsidiaries with significant operations are as follows:

- KCP&L is an integrated, regulated electric utility that provides electricity to customers primarily in the states of Missouri and Kansas. KCP&L has one active wholly owned subsidiary, Kansas City Power & Light Receivables Company (KCP&L Receivables Company).
- KCP&L Greater Missouri Operations Company (GMO) is an integrated, regulated electric utility that provides electricity to customers in the state of Missouri. GMO also provides regulated steam service to certain customers in the St. Joseph, Missouri area. GMO has two active wholly owned subsidiaries, GMO Receivables Company and MPS Merchant Services, Inc. (MPS Merchant). MPS Merchant has certain long-term natural gas contracts remaining from its former non-regulated trading operations.

Great Plains Energy also wholly owns GPE Transmission Holding Company, LLC (GPETHC). GPETHC owns 13.5% of Transource Energy, LLC (Transource) with the remaining 86.5% owned by AEP Transmission Holding Company, LLC (AEPTHC), a subsidiary of American Electric Power Company, Inc. GPETHC accounts for its investment in Transource under the equity method. Transource is focused on the development of competitive electric transmission projects.

Each of Great Plains Energy's and KCP&L's consolidated financial statements includes the accounts of their subsidiaries. Intercompany transactions have been eliminated.

Great Plains Energy's sole reportable business segment is electric utility. See Note 23 for additional information.

Use of Estimates
The process of preparing financial statements in conformity with Generally Accepted Accounting Principles (GAAP) requires the use of estimates and assumptions that affect the reported amounts of certain types of assets, liabilities, revenues and expenses. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements. Accordingly, upon settlement, actual results may differ from estimated amounts.

Cash and Cash Equivalents
Cash equivalents consist of highly liquid investments with original maturities of three months or less at acquisition.

Time Deposit
Consists of a non-negotiable fixed rate investment in a time deposit with an original maturity of greater than three months and is recorded on the balance sheet at cost. The time deposit matures in the first quarter of 2017 and the proceeds from this investment are expected to be used to fund a portion of the cash consideration for the anticipated acquisition of Westar. The Company estimates the fair value of the time deposit, which approximates its carrying

value, using Level 2 inputs based on current interest rates for similar investments with comparable credit risk and time to maturity.

Fair Value of Financial Instruments
The following methods and assumptions were used to estimate the fair value of each class of financial instrument for which it is practicable to estimate that value.

Nuclear decommissioning trust fund - KCP&L's nuclear decommissioning trust fund assets are recorded at fair value based on quoted market prices of the investments held by the fund and/or valuation models.

Derivative instruments - The fair value of commodity derivative instruments is estimated using market quotes, over-the-counter forward price and volatility curves and correlation among fuel prices, net of estimated credit risk. The fair value of interest rate derivative instruments is determined by calculating the net present value of expected payments and receipts under interest rate swaps using observable market inputs including interest rates and LIBOR swap rates. Management also discounts the value by a contingency factor that it believes is representative of what a market participant would use in valuing these instruments in order to account for the contingent nature of the settlement of these instruments.

Pension plans - For financial reporting purposes, the market value of plan assets is the fair value. For regulatory reporting purposes, a five-year smoothing of assets is used to determine fair value.

Derivative Instruments
The Company records derivative instruments on the balance sheet at fair value in accordance with GAAP. Great Plains Energy and KCP&L enter into derivative contracts to manage exposure to commodity price and interest rate fluctuations. Derivative instruments are used solely for hedging purposes and are not issued or held for speculative reasons.

The Company considers various qualitative factors, such as contract and market place attributes, in designating derivative instruments at inception. Great Plains Energy and KCP&L may elect the normal purchases and normal sales (NPNS) exception, which requires the effects of the derivative to be recorded when the underlying contract settles. Great Plains Energy and KCP&L account for derivative instruments that are not designated as NPNS as non-hedging derivatives, which are recorded as assets or liabilities on the consolidated balance sheets at fair value. See Note 19 for additional information regarding derivative financial instruments and hedging activities.

Great Plains Energy and KCP&L offset fair value amounts recognized for derivative instruments under master netting arrangements, which include rights to reclaim cash collateral (a receivable), or the obligation to return cash collateral (a payable).

Utility Plant
Great Plains Energy's and KCP&L's utility plant is stated at historical cost. These costs include taxes, an allowance for the cost of borrowed and equity funds used to finance construction and payroll-related costs, including pensions and other fringe benefits. Replacements, improvements and additions to units of property are capitalized. Repairs of property and replacements of items not considered to be units of property are expensed as incurred (except as discussed under Deferred Refueling Outage Costs). When property units are retired or otherwise disposed, the original cost, net of salvage, is charged to accumulated depreciation. Substantially all of KCP&L's utility plant is pledged as collateral for KCP&L's mortgage bonds under the General Mortgage Indenture and Deed of Trust dated December 1, 1986, as supplemented. A portion of GMO's utility plant is pledged as collateral for GMO's mortgage bonds under the General Mortgage Indenture and Deed of Trust dated April 1, 1946, as supplemented.

As prescribed by The Federal Energy Regulatory Commission (FERC), Allowance for Funds Used During Construction (AFUDC) is charged to the cost of the plant during construction. AFUDC equity funds are included as a non-cash item in non-operating income and AFUDC borrowed funds are a reduction of interest charges. The rates used to compute gross AFUDC are compounded semi-annually. The rates used to compute gross AFUDC for

KCP&L averaged 5.7% in 2016, 3.0% in 2015 and 5.7% in 2014. The rates used to compute gross AFUDC for GMO averaged 1.6% in 2016, 4.2% in 2015 and 6.1% in 2014.

Great Plains Energy's and KCP&L's balances of utility plant, at original cost, with a range of estimated useful lives are listed in the following tables.

Great Plains Energy

December 31	**2016**	**2015**
Utility plant, at original cost	(millions)	
Generation (20 - 60 years)	$ 8,106.4	$ 7,923.8
Transmission (15 - 70 years)	886.3	848.8
Distribution (8 - 66 years)	3,629.1	3,498.6
General (5 - 50 years)	975.9	918.7
Total [(a)]	$ 13,597.7	$ 13,189.9

[(a)] Includes $261.2 million and $214.0 million at December 31, 2016 and 2015, respectively, of land and other assets that are not depreciated.

KCP&L

December 31	**2016**	**2015**
Utility plant, at original cost	(millions)	
Generation (20 - 60 years)	$ 6,350.7	$ 6,222.5
Transmission (15 - 70 years)	484.1	465.3
Distribution (8 - 55 years)	2,298.4	2,215.2
General (5 - 50 years)	791.9	737.4
Total [(a)]	$ 9,925.1	$ 9,640.4

[(a)] Includes $178.0 million and $136.5 million at December 31, 2016 and 2015, respectively, of land and other assets that are not depreciated.

Depreciation and Amortization

Depreciation and amortization of utility plant other than nuclear fuel is computed using the straight-line method over the estimated lives of depreciable property based on rates approved by state regulatory authorities. Annual depreciation rates average approximately 3%. Nuclear fuel is amortized to fuel expense based on the quantity of heat produced during the generation of electricity.

Great Plains Energy's depreciation expense was $308.8 million, $299.4 million and $277.9 million for 2016, 2015 and 2014, respectively. KCP&L's depreciation expense was $215.4 million, $208.5 million and $189.7 million for 2016, 2015 and 2014, respectively.

Nuclear Plant Decommissioning Costs

Nuclear plant decommissioning cost estimates are based on the immediate dismantlement method and include the costs of decontamination, dismantlement and site restoration. Based on these cost estimates, KCP&L contributes to a tax-qualified trust fund to be used to decommission Wolf Creek Generating Station (Wolf Creek). Related liabilities for decommissioning are included on Great Plains Energy's and KCP&L's balance sheets in Asset Retirement Obligations (AROs).

As a result of the authorized regulatory treatment and related regulatory accounting, differences between the decommissioning trust fund asset and the related ARO are recorded as a regulatory asset or liability. See Note 8 for discussion of AROs including those associated with nuclear plant decommissioning costs.

Deferred Refueling Outage Costs

KCP&L uses the deferral method to account for operations and maintenance expenses incurred in support of Wolf Creek's scheduled refueling outages and amortizes them evenly (monthly) over the unit's operating cycle, which is approximately 18 months, until the next scheduled outage. Replacement power costs during an outage are expensed as incurred.

Regulatory Matters
KCP&L and GMO defer items on the balance sheet resulting from the effects of the ratemaking process, which would not be recorded if KCP&L and GMO were not regulated. See Note 6 for additional information concerning regulatory matters.

Revenue Recognition
Great Plains Energy and KCP&L recognize revenues on sales of electricity when the service is provided. Revenues recorded include electric services provided but not yet billed by KCP&L and GMO. Unbilled revenues are recorded for kWh usage in the period following the customers' billing cycle to the end of the month. KCP&L's and GMO's estimate is based on net system kWh usage less actual billed kWhs. KCP&L's and GMO's estimated unbilled kWhs are allocated and priced by regulatory jurisdiction across the rate classes based on actual billing rates.

KCP&L and GMO collect from customers gross receipts taxes levied by state and local governments. These taxes from KCP&L's Missouri customers are recorded gross in operating revenues and general taxes on Great Plains Energy's and KCP&L's statements of comprehensive income. KCP&L's gross receipts taxes collected from Missouri customers were $70.3 million, $62.0 million and $60.4 million in 2016, 2015 and 2014, respectively. These taxes from KCP&L's Kansas customers and GMO's customers are recorded net in operating revenues on Great Plains Energy's and KCP&L's statements of comprehensive income.

Great Plains Energy and KCP&L collect sales taxes from customers and remit to state and local governments. These taxes are presented on a net basis on Great Plains Energy's and KCP&L's statements of comprehensive income.

Great Plains Energy and KCP&L record sale and purchase activity on a net basis in wholesale revenue or purchased power when transacting with Regional Transmission Organization (RTO)/Independent System Operator (ISO) markets.

Allowance for Doubtful Accounts
This reserve represents estimated uncollectible accounts receivable and is based on management's judgment considering historical loss experience and the characteristics of existing accounts. Provisions for losses on receivables are expensed to maintain the allowance at a level considered adequate to cover expected losses. Receivables are charged off against the reserve when they are deemed uncollectible.

Property Gains and Losses
Net gains and losses from the sale of assets and businesses and from asset impairments are recorded in operating expenses.

Asset Impairments
Long-lived assets and finite-lived intangible assets subject to amortization are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If the sum of the undiscounted expected future cash flows from an asset to be held and used is less than the carrying value of the asset, an asset impairment must be recognized in the financial statements. The amount of impairment recognized is the excess of the carrying value of the asset over its fair value.

Goodwill and indefinite lived intangible assets are tested for impairment annually and when an event occurs indicating the possibility that an impairment exists. The annual test must be performed at the same time each year. If the fair value of a reporting unit is less than its carrying value including goodwill, an impairment charge for goodwill must be recognized in the financial statements. To measure the amount of the impairment loss to recognize, the implied fair value of the reporting unit goodwill is compared with its carrying value.

Income Taxes
Income taxes are accounted for using the asset/liability approach. Deferred tax assets and liabilities are determined based on the temporary differences between the financial reporting and tax bases of assets and liabilities, applying enacted statutory tax rates in effect for the year in which the differences are expected to reverse. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion of the deferred tax assets will not be realized.

Great Plains Energy and KCP&L recognize tax benefits based on a "more-likely-than-not" recognition threshold. In addition, Great Plains Energy and KCP&L recognize interest accrued related to unrecognized tax benefits in interest expense and penalties in non-operating expenses.

Great Plains Energy files a consolidated federal income tax return as well as unitary and combined income tax returns in several state jurisdictions with Kansas and Missouri being the most significant. Income taxes for consolidated or combined subsidiaries are allocated to the subsidiaries based on separate company computations of income or loss. KCP&L's income tax provision includes taxes allocated based on its separate company income or loss.

Great Plains Energy and KCP&L have established a net regulatory asset for the additional future revenues to be collected from customers for deferred income taxes. Tax credits are recognized in the year generated except for certain KCP&L and GMO investment tax credits that have been deferred and amortized over the remaining service lives of the related properties.

Environmental Matters
Environmental costs are accrued when it is probable a liability has been incurred and the amount of the liability can be reasonably estimated.

Basic and Diluted Earnings per Common Share Calculation
To determine basic earnings per common share (EPS), preferred stock dividend requirements and redemption premium are deducted from net income before dividing by the average number of common shares outstanding. To determine diluted EPS, preferred stock dividend requirements are added to earnings available for common shareholders for the periods in which the assumed conversion of Great Plains Energy's 7.00% Series B Mandatory Convertible Preferred Stock (Series B Preferred Stock) has a dilutive effect before dividing by the diluted average number of common shares outstanding. The effect of dilutive securities assumes the issuance of common shares applicable to performance shares and restricted stock calculated using the treasury stock method and the number of common shares that would be issued under an assumed conversion of Series B Preferred Stock using the if-converted method.

The following table reconciles Great Plains Energy's basic and diluted EPS.

	2016	2015	2014
	(millions, except per share amounts)		
Income			
Net income	$ 290.0	$ 213.0	$ 242.8
Less: preferred stock dividend requirements and redemption premium	16.5	1.6	1.6
Earnings available for common shareholders	$ 273.5	$ 211.4	$ 241.2
Common Shares Outstanding			
Average number of common shares outstanding	169.4	154.2	153.9
Add: effect of dilutive securities	0.4	0.6	0.2
Diluted average number of common shares outstanding	169.8	154.8	154.1
Basic and Diluted EPS	$ 1.61	$ 1.37	$ 1.57

Anti-dilutive shares excluded from the computation of diluted EPS are detailed in the following table.

	2016	2015	2014
Assumed conversion of Series B Preferred Stock	7,805,460	—	—
Performance shares	—	—	482,987
Restricted stock shares	—	900	3,287

Dividends Declared
In February 2017, Great Plains Energy's Board of Directors (Board) declared a quarterly dividend of $0.275 per share on Great Plains Energy's common stock. The common dividend is payable March 20, 2017, to shareholders of record as of February 27, 2017.

The Board also declared a regular quarterly dividend on Great Plains Energy's Series B Preferred Stock. The dividend will be payable March 15, 2017, to shareholders of record as of March 1, 2017.

In February 2017, KCP&L's Board of Directors declared a cash dividend payable to Great Plains Energy of $57 million payable on March 17, 2017.

New Accounting Standards
In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2014-09, *Revenue from Contracts with Customers*, which requires an entity to recognize the amount of revenue to which it expects to be entitled for the transfer of promised goods or services to customers. The ASU will replace most existing revenue recognition guidance in GAAP when it becomes effective. In August 2015, the FASB issued ASU No. 2015-14, deferring the effective date of ASU No. 2014-09 one year, from January 1, 2017, to January 1, 2018. The Companies plan to adopt ASU No. 2014-09 on January 1, 2018. The standard permits the use of either the retrospective or cumulative effect transition method. The Companies have completed a review of the majority of their revenue arrangements and do not expect the standard to have a material impact on their consolidated financial statements. However, the Companies are still evaluating the impacts on revenue recognition of their remaining revenue arrangements and contracts where collectability is uncertain, as well as the accounting for contributions in aid of construction. The Companies are in the process of determining their method of adoption, which depends in part on completing the evaluation of the remaining items noted above.

In February 2016, the FASB issued ASU No. 2016-02, *Leases*, which requires an entity that is a lessee to record a right-of-use asset and a lease liability for lease payments on the balance sheet for all leases with terms longer than 12 months. Leases will be classified as either finance or operating, with classification affecting the pattern of expense recognition in the income statement. The new guidance is effective for interim and annual periods beginning after December 15, 2018, and is required to be applied using a modified retrospective approach. The Companies are evaluating the effect that ASU No. 2016-02 will have on their consolidated financial statements and related disclosures and have not yet determined the effect of the standard on their ongoing financial reporting.

In March 2016, the FASB issued ASU No. 2016-09, *Compensation-Stock Compensation*, which is intended to simplify several areas of accounting for share-based compensation arrangements, including the income tax impact, classification on the statement of cash flows and forfeitures. The new guidance is effective for interim and annual periods beginning after December 15, 2016, and early adoption is permitted. This guidance will be applied either prospectively, retrospectively or using a modified retrospective transition method, depending on the area covered in this update. The Companies adopted ASU No. 2016-09 effective January 1, 2017 and it will not have a significant impact on their ongoing financial reporting.

In January 2017, the FASB issued ASU No. 2017-04, *Simplifying the Test for Goodwill Impairment,* which eliminates Step 2 of the goodwill impairment test. Step 2 measures a goodwill impairment loss by computing the implied fair value of a reporting unit's goodwill and comparing it with the carrying amount of that goodwill in the event that the reporting unit does not pass Step 1 of the goodwill impairment test. Under the amendments in this ASU, a goodwill impairment loss would be measured by the amount the carrying value of the reporting unit exceeds its fair value as calculated in Step 1 of the goodwill impairment test. The new guidance is effective for annual or any interim goodwill impairment tests in fiscal years beginning after December 15, 2019, with early adoption permitted for tests performed after January 1, 2017. Great Plains Energy anticipates early adopting ASU No. 2017-04 for its 2017 goodwill impairment test and does not anticipate that it will have a significant impact on its ongoing financial reporting.

2. ANTICIPATED ACQUISITION OF WESTAR ENERGY, INC.

On May 29, 2016, Great Plains Energy entered into an Agreement and Plan of Merger (Merger Agreement) by and among Great Plains Energy, Westar, and, from and after its accession to the Merger Agreement, GP Star, Inc., a wholly owned subsidiary of Great Plains Energy in the State of Kansas (Merger Sub). Pursuant to the Merger Agreement, subject to the satisfaction or waiver of certain conditions, Merger Sub will merge with and into Westar, with Westar continuing as the surviving corporation. Upon closing, pursuant to the Merger Agreement, Great Plains Energy will acquire Westar for (i) $51.00 in cash and (ii) a number, rounded to the nearest 1/10,000 of a share, of shares of Great Plains Energy common stock, equal to the Exchange Ratio (as described below) for each share of Westar common stock issued and outstanding immediately prior to the effective time of the merger, with Westar becoming a wholly owned subsidiary of Great Plains Energy.

The Exchange Ratio is calculated as follows:

If the volume-weighted average share price of Great Plains Energy common stock on the New York Stock Exchange for the twenty consecutive full trading days ending on (and including) the third trading day immediately prior to the closing date of the merger (the Great Plains Energy Average Stock Price) is:

(a) greater than $33.2283, the Exchange Ratio will be 0.2709;

(b) greater than or equal to $28.5918 but less than or equal to $33.2283, the Exchange Ratio will be an amount equal to the quotient obtained by dividing (x) $9.00 by (y) the Great Plains Energy Average Stock Price; or

(c) less than $28.5918, the Exchange Ratio will be 0.3148.

Financing

Great Plains Energy plans to finance the cash portion of the merger consideration with equity and debt financing, including (i) $750 million of mandatory convertible preferred equity pursuant to a stock purchase agreement with OCM Credit Portfolio LP (OMERS), (ii) approximately $2.35 billion of equity comprised of a combination of Great Plains Energy common stock and additional mandatory convertible preferred stock, which, as discussed below, was completed in October 2016, and (iii) approximately $4.4 billion in debt.

On May 29, 2016, in connection with the Merger Agreement, Great Plains Energy entered into a commitment letter for a 364-day senior unsecured bridge term loan facility in an aggregate principal amount of $8.017 billion (which has subsequently been reduced to $5.1 billion) to support the anticipated transaction and provide flexibility for the timing of long-term financing. See Note 11 for additional information.

On May 29, 2016, Great Plains Energy entered into a stock purchase agreement with OMERS, pursuant to which Great Plains Energy will issue and sell to OMERS 750,000 shares of preferred stock of Great Plains Energy designated as 7.25% Mandatory Convertible Preferred Stock, Series A (Series A Preferred Stock), without par value, for an aggregate purchase price equal to $750 million at the closing of the merger. See Note 14 for additional information.

On October 3, 2016, Great Plains Energy completed a registered public offering of 60.5 million shares of common stock, without par value, at a public offering price of $26.45 per share, for total gross proceeds of approximately $1.6 billion (net proceeds of approximately $1.55 billion after issuance costs). Concurrent with this offering, Great Plains Energy also completed a registered public offering of 17.3 million depositary shares, each representing a 1/20th interest in a share of Great Plains Energy's Series B Preferred Stock, without par value, at a public offering price of $50 per depositary share for total gross proceeds of $862.5 million (net proceeds of approximately $836.2 million after issuance costs). See Note 14 for additional information on the Series B Preferred Stock.

Regulatory and Shareholder Approvals
Great Plains Energy's anticipated acquisition of Westar was unanimously approved by the Great Plains Energy Board and Westar's Board of Directors (Westar Board). In September 2016, shareholders of Great Plains Energy and Westar approved all proposals necessary for Great Plains Energy's acquisition of Westar at each company's respective shareholder meeting. The anticipated acquisition remains subject to regulatory approvals from The State Corporation Commission of the State of Kansas (KCC), the Public Service Commission of the State of Missouri (MPSC), the Nuclear Regulatory Commission (NRC) and FERC; as well as other customary conditions.

KCC Approval
In June 2016, Great Plains Energy, KCP&L and Westar filed a joint application with KCC for approval of the anticipated acquisition of Westar by Great Plains Energy. Under applicable Kansas regulations, KCC has 300 days following the filing to rule on the transaction. In December 2016, KCC staff filed its testimony and recommended that the KCC not approve the anticipated acquisition, citing concerns with the size of the acquisition premium, the amount of anticipated cost synergies and potential impacts to the quality of service provided to Kansas customers. In January 2017, Great Plains Energy, KCP&L and Westar filed rebuttal testimony responding to KCC staff's concerns. An evidentiary hearing was held in the case from January 30, 2017 through February 7, 2017 and a final order on the joint application is expected by April 24, 2017.

MPSC Approval
On February 22, 2017, the MPSC issued an order directing Great Plains Energy to file an application with the MPSC for approval of the anticipated acquisition of Westar. The order requires Great Plains Energy to file the application within ten days from the date of the order. An evidentiary hearing in the case is expected to occur in early April 2017. While there is not a statutory deadline for an MPSC ruling on the merger application, the MPSC has indicated that they intend to work towards a ruling on a timeline that is consistent with the joint application filed by Great Plains Energy, KCP&L and Westar with KCC, where a final order is expected by April 24, 2017.

Prior to receiving the MPSC order to file an application for approval of the anticipated acquisition of Westar, Great Plains Energy had reached separate stipulations and agreements with the MPSC staff and the Office of the Public Counsel (OPC) in which the MPSC staff and OPC agreed that they would not file complaints alleging that MPSC approval was necessary in order for Great Plains Energy to acquire Westar. The stipulations and agreements impose certain conditions on Great Plains Energy, KCP&L and GMO in the areas of financing, ratemaking, customer service, corporate social responsibility and also include other general provisions. The stipulation and agreement with the MPSC staff, among other things, provides that retail rates for KCP&L Missouri and GMO customers will not increase as a result of the acquisition and that in the event KCP&L's or GMO's credit ratings are downgraded below investment grade as a result of the acquisition, KCP&L and GMO will be restricted from paying a dividend to Great Plains Energy unless approved by the MPSC or until their credit ratings are restored to investment grade. The stipulations and agreements must still be approved by the MPSC and it is expected that they will be considered as part of Great Plains Energy's application for approval of the anticipated acquisition of Westar.

Other Approvals
In July 2016, Great Plains Energy and Westar filed applications with FERC and NRC for approval of the merger. In August 2016, the Securities and Exchange Commission (SEC) declared effective a registration statement including a joint proxy statement with Westar (the Proxy Statement Prospectus) used in connection with the Great Plains Energy and Westar special shareholder meetings that occurred in September 2016. In September 2016, shareholders of Great Plains Energy and Westar approved all proposals necessary for Great Plains Energy's acquisition of Westar at each company's respective shareholder meeting. In September 2016, Great Plains Energy and Westar filed their respective Pre-Merger Notification and Report forms with the Federal Trade Commission (FTC) and the Department of Justice (DOJ) under the Hart-Scott-Rodino (HSR) Act. In October 2016, the FTC granted Great Plains Energy's request for early termination of the waiting period under the HSR Act with respect to the anticipated acquisition, and the DOJ also notified Great Plains Energy that it has closed its investigation of the

antitrust aspects of the anticipated acquisition. In January 2017, The Federal Communications Commission (FCC) consented to the Transfer of Control application filed by Great Plains Energy and Westar relating to the anticipated acquisition.

Termination Fees

The Merger Agreement provides that in connection with the termination of the Merger Agreement under specified circumstances relating to a failure to obtain required regulatory approvals prior to May 31, 2017 (which date may be extended to November 30, 2017 under certain circumstances (the End Date)), a final and nonappealable order enjoining the consummation of the merger in connection with regulatory approvals or failure by Great Plains Energy to consummate the merger once all of the conditions have been satisfied, Great Plains Energy will be required to pay Westar a termination fee of $380 million. In addition, in the event that the Merger Agreement is terminated by (a) either party because the closing has not occurred by the End Date or (b) Westar, as a result of Great Plains Energy's uncured breach of the Merger Agreement, and prior to such termination, an acquisition proposal for Great Plains Energy is publicly disclosed or made to Great Plains Energy, if Great Plains Energy enters into an agreement or consummates a transaction with respect to an acquisition proposal within twelve months following such termination, then Great Plains Energy may be required to pay Westar a termination fee of $180 million. Similarly, in the event that the Merger Agreement is terminated by (x) either party because the closing has not occurred by the End Date or (y) Great Plains Energy, as a result of Westar's uncured breach of the Merger Agreement, and prior to such termination, an acquisition proposal for Westar is publicly disclosed or made to Westar, if Westar enters into an agreement or consummates a transaction with respect to an acquisition proposal within twelve months following such termination, then Westar may be required to pay Great Plains Energy a termination fee of $280 million.

3. SUPPLEMENTAL CASH FLOW INFORMATION

Great Plains Energy Other Operating Activities

Year Ended December 31	**2016**	**2015**	**2014**
Cash flows affected by changes in:		(millions)	
Receivables	$ (18.3)	$ 12.5	$ 3.0
Accounts receivable pledged as collateral	2.6	(4.0)	4.0
Fuel inventories	9.6	(28.3)	(13.7)
Materials and supplies	(6.5)	(3.0)	(0.4)
Accounts payable	(25.4)	(11.4)	15.2
Accrued taxes	8.1	1.1	8.3
Accrued interest	6.1	3.4	(4.1)
Deferred refueling outage costs	(3.1)	(6.7)	17.0
Pension and post-retirement benefit obligations	27.4	18.5	25.5
Allowance for equity funds used during construction	(6.6)	(4.8)	(18.0)
Fuel recovery mechanisms	(46.9)	47.5	(28.5)
Solar rebates paid	(4.5)	(9.0)	(43.2)
Other	15.2	(2.9)	(12.3)
Total other operating activities	$ (42.3)	$ 12.9	$ (47.2)
Cash paid during the period:			
Interest	$ 191.2	$ 182.2	$ 174.8
Income taxes	$ 0.1	$ 0.1	$ —
Non-cash investing activities:			
Liabilities accrued for capital expenditures	$ 32.4	$ 35.7	$ 57.4

KCP&L Other Operating Activities

Year Ended December 31	**2016**	**2015**	**2014**
Cash flows affected by changes in:		(millions)	
Receivables	$ (12.4)	$ 2.6	$ (18.1)
Fuel inventories	10.6	(24.7)	(8.5)
Materials and supplies	(4.3)	(4.5)	(1.1)
Accounts payable	(30.5)	(18.0)	20.4
Accrued taxes	67.9	(19.0)	(42.5)
Accrued interest	—	3.4	(0.1)
Deferred refueling outage costs	(3.1)	(6.7)	17.0
Pension and post-retirement benefit obligations	28.6	18.4	26.9
Allowance for equity funds used during construction	(6.6)	(3.8)	(16.0)
Fuel recovery mechanisms	(53.7)	3.5	(2.2)
Solar rebates paid	(3.1)	(7.2)	(17.3)
Other	4.5	(5.5)	(23.2)
Total other operating activities	$ (2.1)	$ (61.5)	$ (64.7)
Cash paid during the period:			
Interest	$ 127.0	$ 120.2	$ 112.1
Income taxes	$ —	$ —	$ 30.2
Non-cash investing activities:			
Liabilities accrued for capital expenditures	$ 27.2	$ 23.9	$ 48.8

4. RECEIVABLES

Great Plains Energy's and KCP&L's receivables are detailed in the following table.

	December 31	
	2016	**2015**
Great Plains Energy	(millions)	
Customer accounts receivable - billed	$ 26.2	$ 3.4
Customer accounts receivable - unbilled	79.1	71.6
Allowance for doubtful accounts - customer accounts receivable	(4.0)	(3.8)
Other receivables	64.7	76.5
Total	$ 166.0	$ 147.7
KCP&L		
Customer accounts receivable - billed	$ 25.5	$ 2.8
Customer accounts receivable - unbilled	63.7	58.8
Allowance for doubtful accounts - customer accounts receivable	(1.8)	(1.8)
Other receivables	51.7	69.4
Total	$ 139.1	$ 129.2

Great Plains Energy's and KCP&L's other receivables at December 31, 2016 and 2015, consisted primarily of receivables from partners in jointly owned electric utility plants and wholesale sales receivables.

Sale of Accounts Receivable – KCP&L and GMO

KCP&L and GMO sell all of their retail electric accounts receivable to their wholly owned subsidiaries, KCP&L Receivables Company and GMO Receivables Company, respectively, which in turn sell an undivided percentage ownership interest in the accounts receivable to Victory Receivables Corporation, an independent outside investor. Each of KCP&L Receivables Company's and GMO Receivables Company's sale of the undivided percentage ownership interest in accounts receivable to Victory Receivables Corporation is accounted for as a secured borrowing with accounts receivable pledged as collateral and a corresponding short-term collateralized note payable recognized on the balance sheets. At December 31, 2016 and 2015, Great Plains Energy's accounts receivable pledged as collateral and the corresponding short-term collateralized note payable were $172.4 million and $175.0 million, respectively. At December 31, 2016 and 2015, KCP&L's accounts receivable pledged as collateral and the corresponding short-term collateralized note payable were $110.0 million. KCP&L's agreement expires in September 2017 and allows for $110 million in aggregate outstanding principal amount of borrowings at any time. GMO's agreement expires in September 2017 and allows for $65 million in aggregate outstanding principal of borrowings from mid-November through mid-June and then increases to $80 million from mid-June through mid-November.

5. NUCLEAR PLANT

KCP&L owns 47% of Wolf Creek Generating Station (Wolf Creek), its only nuclear generating unit. Wolf Creek is located in Coffey County, Kansas, just northeast of Burlington, Kansas. Wolf Creek's operating license expires in 2045. Wolf Creek is regulated by the NRC with respect to licensing, operations and safety-related requirements.

Spent Nuclear Fuel and High-Level Radioactive Waste

Under the Nuclear Waste Policy Act of 1982, the Department of Energy (DOE) is responsible for the permanent disposal of spent nuclear fuel. Wolf Creek historically paid the DOE a quarterly fee of one-tenth of a cent for each kWh of net nuclear generation delivered and sold for the future disposal of spent nuclear fuel. In May 2014, this fee was set to zero.

In 2010, the DOE filed a motion with the NRC to withdraw its then pending application to the NRC 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. In 2011, the NRC announced that it was evenly divided on whether to take affirmative action to overturn or uphold the board's decision and ordered the licensing board, consistent with budgetary limitations, to close out its work on the DOE's application. In August 2013, a federal court of appeals ruled that the NRC must resume its review of the DOE's application to the extent of appropriated funds. With the available funds, the NRC was able to complete its technical review of the Yucca Mountain application but was not able to resume the licensing hearing.

Wolf Creek is currently evaluating alternatives for expanding its existing on-site spent nuclear fuel storage to provide additional capacity prior to 2025. Management 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.

Low-Level Radioactive Waste

Wolf Creek disposes of most of its low-level radioactive waste (Class A waste) at an existing third-party repository in Utah. Management expects that the site located in Utah will remain available to Wolf Creek for disposal of its Class A waste. Wolf Creek has contracted with a waste processor that will process, take title and dispose in another state most of the remainder of Wolf Creek's low-level radioactive waste (Classes B and C waste, which is higher in radioactivity but much lower in volume). Should on-site waste storage be needed in the future, Wolf Creek has current storage capacity on site for about four years' generation of Classes B and C waste and believes it will be able to expand that storage capacity as needed if it becomes necessary to do so.

Nuclear Plant Decommissioning Costs

The MPSC and KCC require KCP&L and the other owners of Wolf Creek to submit an updated decommissioning cost study every three years and to propose funding levels. The most recent study was submitted to the MPSC and KCC in August 2014 and is the basis for the current cost of decommissioning estimates in the following table. Funding levels included in KCP&L retail rates have not changed.

	KCC	MPSC
	(millions)	
Current cost of decommissioning (in 2014 dollars)		
Total Station	$ 765.1	$ 765.1
KCP&L's 47% Share	359.6	359.6
Future cost of decommissioning (in 2045-2053 dollars) [(a)]		
Total Station	$ 2,201.5	$ 2,253.1
KCP&L's 47% Share	1,034.7	1,059.0
Annual escalation factor	3.15%	3.22%
Annual return on trust assets [(b)]	6.29%	5.81%

[(a)] Total future cost over an eight year decommissioning period

[(b)] The 6.29% and 5.81% rate of return for KCC and MPSC, respectively, is through 2025. The rates then systematically decrease through 2053 to 0.72% and 2.22% for KCC and MPSC, respectively, based on the assumption that the fund's investment mix will become increasingly conservative as the decommissioning period approaches.

Nuclear Decommissioning Trust Fund

In 2016 and 2015, KCP&L contributed approximately $3.3 million to a tax-qualified trust fund to be used to decommission Wolf Creek. Amounts funded are charged to other operating expense and recovered in customers' rates. The funding level assumes a projected level of return on trust assets. If the actual return on trust assets is below the projected level or actual decommissioning costs are higher than estimated, KCP&L could be responsible for the balance of funds required; however, while there can be no assurances, management believes a rate increase would be allowed to recover decommissioning costs over the remaining life of the unit.

The following table summarizes the change in Great Plains Energy's and KCP&L's nuclear decommissioning trust fund.

	2016	2015
Decommissioning Trust	(millions)	
Beginning balance January 1	$ 200.7	$ 199.0
Contributions	3.3	3.3
Earned income, net of fees	4.1	3.4
Net realized gains	0.3	0.7
Net unrealized gains (losses)	14.5	(5.7)
Ending balance December 31	$ 222.9	$ 200.7

The nuclear decommissioning trust is reported at fair value on the balance sheets and is invested in assets as detailed in the following table.

	December 31							
	2016				2015			
	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
	(millions)							
Equity securities	$ 93.3	$ 62.1	$ (1.5)	$ 153.9	$ 89.6	$ 47.9	$ (2.1)	$ 135.4
Debt securities	63.4	2.3	(0.5)	65.2	59.6	2.6	(0.5)	61.7
Other	3.8	—	—	3.8	3.6	—	—	3.6
Total	$ 160.5	$ 64.4	$ (2.0)	$ 222.9	$ 152.8	$ 50.5	$ (2.6)	$ 200.7

The weighted average maturity of debt securities held by the trust at December 31, 2016, was approximately 8 years. The costs of securities sold are determined on the basis of specific identification. The following table summarizes the realized gains and losses from the sale of securities in the nuclear decommissioning trust fund.

	2016	2015	2014
	(millions)		
Realized gains	$ 1.6	$ 5.3	$ 1.4
Realized losses	(1.3)	(4.6)	(1.0)

Nuclear Insurance

The owners of Wolf Creek (Owners) maintain nuclear insurance for Wolf Creek for nuclear liability, nuclear property and accidental outage. These policies contain certain industry standard exclusions, including, but not limited to, ordinary wear and tear, and war. The nuclear property insurance programs subscribed to by members of the nuclear power generating industry include industry aggregate limits for acts of terrorism and related losses, including replacement power costs. There is no industry aggregate limit for liability claims related to terrorism, regardless of the number of acts of terrorism affecting Wolf Creek or any other nuclear energy liability policy or the number of policies in place. An industry aggregate limit of $3.2 billion plus any reinsurance recoverable by Nuclear Electric Insurance Limited (NEIL), the Owners' insurance provider, exists for property claims related to nuclear acts of terrorism, including accidental outage power costs for nuclear acts of terrorism affecting Wolf Creek or any other nuclear energy facility property policy within twelve months from the date of the first act. An industry aggregate limit of $1.8 billion exists for property claims related to non-nuclear acts of terrorism. These limits plus any recoverable reinsurance are the maximum amount to be paid to members who sustain losses or damages from these types of terrorist acts. In addition, industry-wide retrospective assessment programs (discussed below) can apply once these insurance programs have been exhausted.

In the event of a catastrophic loss at Wolf Creek, the insurance coverage may not be adequate to cover property damage and extra expenses incurred. Uninsured losses, to the extent not recovered through rates, would be assumed by KCP&L and the other owners and could have a material effect on Great Plains Energy's and KCP&L's results of operations, financial position and cash flows.

Nuclear Liability Insurance

Pursuant to the Price-Anderson Act, which was reauthorized through December 31, 2025, by the Energy Policy Act of 2005, the Owners are required to insure against public liability claims resulting from nuclear incidents to the full limit of public liability, which is currently $13.4 billion. This limit of liability consists of the maximum available commercial insurance of $0.4 billion and the remaining $13.0 billion is provided through an industry-wide retrospective assessment program mandated by law, known as the Secondary Financial Protection (SFP) program. Under the SFP program, the Owners can be assessed up to $127.3 million ($59.8 million, KCP&L's 47% share) per incident at any commercial reactor in the country, payable at no more than $19.0 million ($8.9 million, KCP&L's 47% share) per incident per year. This assessment is subject to an inflation adjustment based on the Consumer

Price Index and applicable premium taxes. In addition, the U.S. Congress could impose additional revenue-raising measures to pay claims.

Nuclear Property Insurance
The Owners carry decontamination liability, premature decommissioning liability and property damage insurance from NEIL for Wolf Creek totaling approximately $2.8 billion ($1.3 billion, KCP&L's 47% share). In the event of an accident, insurance proceeds must first be used for reactor stabilization and site decontamination in accordance with a plan mandated by the NRC. KCP&L's share of any remaining proceeds can be used for further decontamination, property damage restoration and premature decommissioning costs. Premature decommissioning coverage applies only if an accident at Wolf Creek exceeds $500 million in property damage and decontamination expenses, and only after trust funds have been exhausted.

Accidental Nuclear Outage Insurance
The Owners also carry additional insurance from NEIL to cover costs of replacement power and other extra expenses incurred in the event of a prolonged outage resulting from accidental property damage at Wolf Creek.

Under all NEIL policies, the Owners are subject to retrospective assessments if NEIL losses, for each policy year, exceed the accumulated funds available to the insurer under that policy. The estimated maximum amount of retrospective assessments under the current policies could total approximately $37.5 million ($17.6 million, KCP&L's 47% share) per policy year.

6. REGULATORY MATTERS

KCP&L Kansas 2016 Abbreviated Rate Case Proceedings
In November 2016, KCP&L filed an abbreviated application with the KCC to request a decrease to its retail revenues of $2.8 million, reflecting the true-up to actuals of construction and environmental upgrade costs at the La Cygne station and Wolf Creek capital addition costs and the removal of certain regulatory asset and liability amortizations. The previously approved return on equity and rate-making ratio for KCP&L will not be addressed in this case. Testimony from KCC staff and other parties regarding the case is expected in April 2017, with an evidentiary hearing to occur in May 2017. The decrease to retail revenues is anticipated to be effective in July 2017.

KCP&L Missouri 2016 Rate Case Proceedings
In July 2016, KCP&L filed an application with the MPSC to request an increase to its retail revenues of $62.9 million, with a return on equity of 9.9% and a rate-making equity ratio of 49.88%. The request reflects increases in infrastructure investment costs, costs for regional transmission lines, property tax costs and costs to comply with environmental and cybersecurity mandates. KCP&L also requested an additional $27.2 million increase associated with rebasing fuel and purchased power expense. In November 2016, MPSC staff filed testimony regarding the case stating that they did not have sufficient information to support a change in rates but in the event that new rates were approved, recommended a return on equity of 8.65%, which is on the upper end of their range of 7.9% to 8.75%.

In February 2017, KCP&L, MPSC staff and other parties to the case filed a non-unanimous stipulation and agreement resolving certain issues in the case. The stipulation and agreement is pending MPSC approval. An evidentiary hearing also occurred in February 2017. An order on the remaining issues in the case is anticipated to be received to accommodate new rates to be effective in May 2017.

GMO Missouri 2016 Rate Case Proceedings
In February 2016, GMO filed an application with the MPSC to request an increase to its retail revenues of $59.3 million, with a return on equity of 9.9% and a rate-making equity ratio of 54.83%. The request included recovery of increased transmission and property tax expenses as well as costs for infrastructure and system improvements to continue to provide reliable electric service.

In September 2016, GMO, the MPSC staff and certain intervenors reached several non-unanimous stipulations and agreements resolving all issues in the case. In September 2016, the MPSC issued an order for GMO approving the non-unanimous stipulations and agreements and authorizing an increase in annual revenues of $3.0 million and a return on equity of 9.5% to 9.75%. The rates established by the order took effect on February 22, 2017.

Regulatory Assets and Liabilities

Great Plains Energy and KCP&L have recorded assets and liabilities on their consolidated balance sheets resulting from the effects of the ratemaking process, which would not otherwise be recorded if the Companies were not regulated. Regulatory assets represent incurred costs that are probable of recovery from future revenues. Regulatory liabilities represent future reductions in revenues or refunds to customers.

Management regularly assesses whether regulatory assets and liabilities are probable of future recovery or refund by considering factors such as decisions by the MPSC, KCC or FERC in KCP&L's and GMO's rate case filings; decisions in other regulatory proceedings, including decisions related to other companies that establish precedent on matters applicable to the Companies; and changes in laws and regulations. If recovery or refund of regulatory assets or liabilities is not approved by regulators or is no longer deemed probable, these regulatory assets or liabilities are recognized in the current period results of operations. The Companies' continued ability to meet the criteria for recording regulatory assets and liabilities may be affected in the future by restructuring and deregulation in the electric industry or changes in accounting rules. In the event that the criteria no longer applied to any or all of the Companies' operations, the related regulatory assets and liabilities would be written off unless an appropriate regulatory recovery mechanism were provided. Additionally, these factors could result in an impairment on utility plant assets.

Great Plains Energy's and KCP&L's regulatory assets and liabilities are detailed in the following table.

	December 31					
	2016			2015		
	KCP&L	GMO	Great Plains Energy	KCP&L	GMO	Great Plains Energy
Regulatory Assets	(millions)					
Taxes recoverable through future rates	$ 123.9	$ 24.8	$ 148.7	$ 125.0	$ 26.4	$ 151.4
Loss on reacquired debt	10.0 [a]	1.7 [a]	11.7	11.3	2.2	13.5
Cost of removal	28.6	—	28.6	12.9	—	12.9
Asset retirement obligations	69.6	24.9	94.5	57.9	19.5	77.4
Pension and post-retirement costs	367.9 [b]	104.7 [b]	472.6	358.5	98.9	457.4
Deferred customer programs	45.9 [c]	27.4 [d]	73.3	50.3	20.8	71.1
Fuel recovery mechanism	69.9 [e]	—	69.9	16.3	0.1	16.4
Derivative instruments	—	—	—	0.5	6.3	6.8
Iatan No. 1 and common facilities depreciation and carrying costs	13.6 [f]	5.0 [f]	18.6	14.1	5.2	19.3
Iatan No. 2 construction accounting costs	26.9 [g]	16.1 [g]	43.0	28.7	16.0	44.7
Kansas property tax surcharge	3.6 [e]	—	3.6	6.8	—	6.8
Solar rebates	29.2 [e]	41.6 [e]	70.8	33.6	49.0	82.6
Transmission delivery charge	3.1 [e]	—	3.1	1.7	—	1.7
La Cygne deferred depreciation	2.8 [h]	—	2.8	2.9	—	2.9
Other	6.8 [e]	—	6.8	11.9	2.3	14.2
Total	$ 801.8	$ 246.2	$ 1,048.0	$ 732.4	$ 246.7	$ 979.1
Regulatory Liabilities						
Emission allowances	$ 62.1	$ —	$ 62.1	$ 66.1	$ —	$ 66.1
Asset retirement obligations	99.7	—	99.7	86.5	—	86.5
Cost of removal	—	65.1 [i]	65.1	—	68.2	68.2
Fuel recovery mechanism	—	11.6	11.6	—	5.0	5.0
Pension and post-retirement costs	15.3	7.4	22.7	4.8	3.7	8.5
Other	10.3	38.4	48.7	7.2	42.9	50.1
Total	$ 187.4	$ 122.5	$ 309.9	$ 164.6	$ 119.8	$ 284.4

[a] Amortized over the life of the related new debt issuances or the remaining lives of the old debt issuances if no new debt was issued.

[b] Represents unrecognized gains and losses, prior service and transition costs that will be recognized in future net periodic pension and post-retirement costs, pension settlements amortized over various periods and financial and regulatory accounting method differences that will be eliminated over the life of the pension plans. Of these amounts, $360.7 million and $65.1 million for KCP&L and GMO, respectively, are not included in rate base and are amortized over various periods.

[c] $13.2 million not included in rate base and amortized over various periods.

[d] $15.4 million not included in rate base and amortized over various periods.

[e] Not included in rate base and amortized over various periods.

[f] Included in rate base and amortized through 2038.

[g] Included in rate base and amortized through 2058.

[h] Included in rate base and amortized through 2040.

[i] Estimated cumulative net provision for future removal costs.

7. GOODWILL AND INTANGIBLE ASSETS

Accounting rules require goodwill to be tested for impairment annually and when an event occurs indicating the possibility that an impairment exists. The annual impairment test for the $169.0 million of GMO acquisition goodwill was conducted on September 1, 2016. The goodwill impairment test is a two step process. See Note 1 for additional information regarding the Company's plans to adopt ASU No. 2017-04 for its 2017 goodwill impairment test. The first step compares the fair value of a reporting unit to its carrying amount, including goodwill, to identify potential impairment. If the carrying amount exceeds the fair value of the reporting unit, the second step of the test is performed, consisting of assignment of the reporting unit's fair value to its assets and liabilities to determine an implied fair value of goodwill, which is compared to the carrying amount of goodwill to determine the impairment loss, if any, to be recognized in the financial statements. Great Plains Energy's regulated electric utility operations are considered one reporting unit for assessment of impairment, as they are included within the same operating segment and have similar economic characteristics. The determination of fair value of the reporting unit consisted of two valuation techniques: an income approach consisting of a discounted cash flow analysis and a market approach consisting of a determination of reporting unit invested capital using market multiples derived from the historical revenue, earnings before interest, income taxes, depreciation and amortization (EBITDA), net utility asset values and market prices of stock of peer companies. The results of the two techniques were evaluated and weighted to determine a point within the range that management considered representative of fair value for the reporting unit. Fair value of the reporting unit exceeded the carrying amount, including goodwill; therefore, there was no impairment of goodwill.

Great Plains Energy's and KCP&L's intangible assets are included in electric utility plant on the consolidated balance sheets and are detailed in the following table.

	December 31, 2016		December 31, 2015	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Great Plains Energy	(millions)			
Computer software	$ 355.2	$ (219.1)	$ 333.0	$ (191.8)
Asset improvements	28.8	(6.7)	28.3	(6.1)
KCP&L				
Computer software	$ 338.3	$ (203.1)	$ 315.5	$ (177.7)
Asset improvements	13.6	(1.8)	13.1	(1.5)

Great Plains Energy's and KCP&L's amortization expense related to intangible assets is detailed in the following table.

	2016	2015
	(millions)	
Great Plains Energy	$ 29.1	$ 28.6
KCP&L	25.7	24.7

The following table provides the estimated amortization expense related to Great Plains Energy's and KCP&L's intangible assets for 2017 through 2021 for the intangible assets included in the consolidated balance sheets at December 31, 2016.

	2017	2018	2019	2020	2021
			(millions)		
Great Plains Energy	$ 26.1	$ 23.7	$ 21.5	$ 18.0	$ 14.3
KCP&L	24.9	23.2	21.0	17.6	13.9

8. ASSET RETIREMENT OBLIGATIONS

AROs associated with tangible long-lived assets are legal obligations that exist under enacted laws, statutes and written or oral contracts, including obligations arising under the doctrine of promissory estoppel. These liabilities are recognized at estimated fair value as incurred with a corresponding amount capitalized as part of the cost of the related long-lived assets and depreciated over their useful lives. Accretion of the liabilities due to the passage of time is recorded to a regulatory asset and/or liability. Changes in the estimated fair values of the liabilities are recognized when known.

KCP&L has AROs related to decommissioning Wolf Creek, site remediation of its Spearville Wind Energy Facilities, asbestos abatement, removal of storage tanks and closure and post-closure of ponds and landfills containing coal combustion residuals (CCRs). GMO has AROs related to asbestos abatement, removal of storage tanks and closure and post-closure of ponds and landfills containing CCRs.

Additionally, certain wiring used in Great Plains Energy's and KCP&L's generating stations include asbestos insulation, which would require special handling if disturbed. Due to the inability to reasonably estimate the quantities or the amount of disturbance that will be necessary during dismantlement at the end of the life of a plant, the fair value of this ARO cannot be reasonably estimated at this time. Management will continue to monitor the obligation and will recognize a liability in the period in which sufficient information becomes available to reasonably estimate its fair value.

On April 17, 2015, the Environmental Protection Agency (EPA) published new regulations to regulate the disposal of CCRs at electric generation facilities. The CCR rule represents legal obligations of Great Plains Energy and KCP&L as to the closure and post-closure of its ponds and landfills containing CCRs. In 2016, Great Plains Energy and KCP&L revised their AROs by $42.1 million and $40.1 million, respectively, due to an increase in cost estimates for the closure of ponds and landfills containing CCRs at KCP&L's electric generating facilities. As a result of the CCR rule being published, Great Plains Energy and KCP&L increased their AROs $69.5 million and $51.3 million, respectively, in the second quarter of 2015.

The following table summarizes the change in Great Plains Energy's and KCP&L's AROs.

	Great Plains Energy		KCP&L	
	2016	2015	2016	2015
	(millions)			
Beginning balance	$ 275.9	$ 195.9	$ 239.3	$ 177.7
Additions	1.6	54.5	1.3	34.6
Revision in timing and/or estimates	42.1	20.5	40.1	22.2
Settlements	(17.4)	(7.8)	(15.0)	(6.7)
Accretion	13.8	12.8	12.3	11.5
Ending balance	$ 316.0	$ 275.9	$ 278.0	$ 239.3

ARO settlement activity in 2016 and 2015 primarily consists of the remediation of AROs for the closure of ponds and landfills containing CCRs at KCP&L and GMO.

9. PENSION PLANS AND OTHER EMPLOYEE BENEFITS

Great Plains Energy maintains defined benefit pension plans for the majority of KCP&L's and GMO's active and inactive employees, including officers, and its 47% ownership share of Wolf Creek Nuclear Operating Corporation (WCNOC) defined benefit plans. For the majority of employees, pension benefits under these plans reflect the employees' compensation, years of service and age at retirement. Effective in 2014, Great Plains Energy's non-union plan was closed to future employees. Great Plains Energy also provides certain post-retirement health care and life insurance benefits for substantially all retired employees of KCP&L, GMO and its 47% ownership share of WCNOC.

KCP&L and GMO record pension and post-retirement expense in accordance with rate orders from the MPSC and KCC that allow the difference between pension and post-retirement costs under GAAP and costs for ratemaking to be recognized as a regulatory asset or liability. This difference between financial and regulatory accounting methods is due to timing and will be eliminated over the life of the plans.

In 2014, Great Plains Energy incurred pension settlement charges of $8.5 million as a result of accelerated pension distributions.

The following pension benefits tables provide information relating to the funded status of all defined benefit pension plans on an aggregate basis as well as the components of net periodic benefit costs. For financial reporting purposes, the market value of plan assets is the fair value. For regulatory reporting purposes, a five-year smoothing of assets is used to determine fair value. Net periodic benefit costs reflect total plan benefit costs prior to the effects of capitalization and sharing with joint owners of power plants.

	Pension Benefits		Other Benefits	
	2016	2015	2016	2015
Change in projected benefit obligation (PBO)		(millions)		
PBO at January 1	$ 1,154.8	$ 1,186.8	$ 137.5	$ 165.2
Service cost	42.0	45.3	2.6	3.3
Interest cost	52.9	50.3	6.1	6.8
Contribution by participants	—	—	5.3	6.9
Amendments	—	—	(10.1)	(7.1)
Actuarial (gain) loss	65.5	(59.4)	0.6	(23.6)
Benefits paid	(70.6)	(68.2)	(11.9)	(14.0)
PBO at December 31	$ 1,244.6	$ 1,154.8	$ 130.1	$ 137.5
Change in plan assets				
Fair value of plan assets at January 1	$ 723.9	$ 730.0	$ 114.3	$ 110.6
Actual return on plan assets	51.1	(16.3)	2.6	(0.1)
Contributions by employer and participants	69.8	76.9	10.2	17.6
Benefits paid	(68.0)	(66.7)	(11.5)	(13.8)
Fair value of plan assets at December 31	$ 776.8	$ 723.9	$ 115.6	$ 114.3
Funded status at December 31	$ (467.8)	$ (430.9)	$ (14.5)	$ (23.2)
Amounts recognized in the consolidated balance sheets				
Non-current asset	$ —	$ —	$ 9.0	$ 4.5
Current pension and other post-retirement liability	(2.2)	(2.6)	(0.8)	(0.8)
Noncurrent pension liability and other post-retirement liability	(465.6)	(428.3)	(22.7)	(26.9)
Net amount recognized before regulatory treatment	(467.8)	(430.9)	(14.5)	(23.2)
Accumulated OCI or regulatory asset/liability	476.9	461.2	(23.6)	(9.4)
Net amount recognized at December 31	$ 9.1	$ 30.3	$ (38.1)	$ (32.6)
Amounts in accumulated OCI or regulatory asset/liability not yet recognized as a component of net periodic benefit cost:				
Actuarial (gain) loss	$ 242.5	$ 230.7	$ (0.7)	$ (3.3)
Prior service cost	3.2	3.9	(8.0)	3.4
Other	231.2	226.6	(14.9)	(9.5)
Net amount recognized at December 31	$ 476.9	$ 461.2	$ (23.6)	$ (9.4)

	Pension Benefits			Other Benefits		
	2016	2015	2014	2016	2015	2014
Components of net periodic benefit costs			(millions)			
Service cost	$ 42.0	$ 45.3	$ 36.7	$ 2.6	$ 3.3	$ 3.7
Interest cost	52.9	50.3	50.1	6.1	6.8	7.9
Expected return on plan assets	(49.2)	(51.7)	(50.2)	(3.1)	(2.9)	(2.6)
Prior service cost	0.7	0.8	0.9	1.2	3.1	3.1
Recognized net actuarial (gain) loss	51.8	51.4	50.0	(1.5)	0.2	(0.1)
Transition obligation	—	—	—	—	0.2	0.2
Settlement charges	—	—	8.5	—	—	—
Net periodic benefit costs before regulatory adjustment	98.2	96.1	96.0	5.3	10.7	12.2
Regulatory adjustment	(4.9)	(9.8)	(11.3)	6.0	4.4	4.3
Net periodic benefit costs	93.3	86.3	84.7	11.3	15.1	16.5
Other changes in plan assets and benefit obligations recognized in OCI or regulatory assets/liabilities						
Current year net (gain) loss	63.6	8.6	175.8	1.1	(20.6)	(1.8)
Amortization of gain (loss)	(51.8)	(51.4)	(50.0)	1.5	(0.2)	0.1
Prior service cost	—	—	—	(10.2)	(7.0)	—
Amortization of prior service cost	(0.7)	(0.8)	(0.9)	(1.2)	(3.1)	(3.1)
Amortization of transition obligation	—	—	—	—	(0.2)	(0.2)
Other regulatory activity	4.6	4.3	7.3	(5.4)	(4.4)	(4.2)
Total recognized in OCI or regulatory asset/ liability	15.7	(39.3)	132.2	(14.2)	(35.5)	(9.2)
Total recognized in net periodic benefit costs and OCI or regulatory asset/liability	$ 109.0	$ 47.0	$ 216.9	$ (2.9)	$ (20.4)	$ 7.3

For financial reporting purposes, the estimated prior service cost and net loss for the defined benefit plans that will be amortized from accumulated other comprehensive income (OCI) or a regulatory asset into net periodic benefit cost in 2017 are $0.7 million and $49.7 million, respectively. For financial reporting purposes, net actuarial gains and losses are recognized on a rolling five-year average basis. For regulatory reporting purposes, net actuarial gains and losses are amortized over ten years. The estimated net gain for the other post-retirement benefit plans that will be amortized from accumulated OCI or a regulatory asset into net periodic benefit cost in 2017 is $0.5 million.

The accumulated benefit obligation (ABO) for all defined benefit pension plans was $1,090.2 million and $1,017.6 million at December 31, 2016, and 2015, respectively. Pension and other post-retirement benefit plans with the PBO, ABO or accumulated other post-retirement benefit obligation (APBO) in excess of the fair value of plan assets at year-end are detailed in the following table.

	2016	2015
Pension plans with the PBO in excess of plan assets	(millions)	
Projected benefit obligation	$ 1,244.6	$ 1,154.8
Fair value of plan assets	776.8	723.9
Pension plans with the ABO in excess of plan assets		
Accumulated benefit obligation	$ 1,090.2	$ 1,017.6
Fair value of plan assets	776.8	723.9
Other post-retirement benefit plans with the APBO in excess of plan assets		
Accumulated other post-retirement benefit obligation	$ 61.7	$ 108.5
Fair value of plan assets	38.3	80.8

The GMO Supplemental Executive Retirement Plan (SERP) is reflected as an unfunded ABO of $23.6 million. Great Plains Energy has approximately $15.8 million of assets in a non-qualified trust for this plan as of December 31, 2016, and expects to fund future benefit payments from these assets.

The expected long-term rate of return on plan assets represents Great Plains Energy's estimate of the long-term return on plan assets and is based on historical and projected rates of return for current and planned asset classes in the plans' investment portfolios. Assumed projected rates of return for each asset class were selected after analyzing historical experience and future expectations of the returns of various asset classes. Based on the target asset allocation for each asset class, the overall expected rate of return for the portfolios was developed and adjusted for the effect of projected benefits paid from plan assets and future plan contributions. The following tables provide the weighted-average assumptions used to determine benefit obligations and net costs.

Weighted-average assumptions used to determine the benefit obligation at December 31	Pension Benefits		Other Benefits	
	2016	2015	2016	2015
Discount rate	4.31%	4.54%	4.20%	4.47%
Rate of compensation increase	3.62%	3.62%	3.50%	3.50%

Weighted-average assumptions used to determine net costs for years ended December 31	Pension Benefits		Other Benefits	
	2016	2015	2016	2015
Discount rate	4.54%	4.22%	4.47%	4.14%
Expected long-term return on plan assets	7.14%	7.14%	2.54% *	2.81% *
Rate of compensation increase	3.62%	3.62%	3.50%	3.50%

*after tax

Great Plains Energy expects to contribute $79.6 million to the pension plans in 2017 to meet ERISA funding requirements and regulatory orders, the majority of which is expected to be paid by KCP&L. Great Plains Energy's funding policy is to contribute amounts sufficient to meet the ERISA funding requirements and MPSC and KCC rate orders plus additional amounts as considered appropriate; therefore, actual contributions may differ from expected contributions. Great Plains Energy also expects to contribute $4.6 million to other post-retirement benefit plans in 2017, the majority of which is expected to be paid by KCP&L.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid through 2026.

	Pension Benefits	Other Benefits
	(millions)	
2017	$ 84.9	$ 8.9
2018	81.0	9.4
2019	84.1	10.0
2020	85.9	10.3
2021	87.7	10.7
2022-2026	448.5	58.7

Pension plan assets are managed in accordance with prudent investor guidelines contained in the ERISA requirements. The investment strategy supports the objective of the fund, which is to earn the highest possible return on plan assets within a reasonable and prudent level of risk. The portfolios are invested, and periodically rebalanced, to achieve targeted allocations of approximately 34% U.S. large cap and small cap equity securities, 21% international equity securities, 36% fixed income securities, 6% real estate, 1% commodities and 2% hedge funds. Fixed income securities include domestic and foreign corporate bonds, collateralized mortgage obligations and asset-backed securities, U.S. government agency, state and local obligations, U.S. Treasury notes and money market funds.

The fair values of Great Plains Energy's pension plan assets at December 31, 2016 and 2015, by asset category are in the following tables.

		Fair Value Measurements Using			
Description	**December 31 2016**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Assets measured at NAV**
			(millions)		
Pension Plans					
Equity securities					
U.S. [a]	$ 247.6	$ 213.0	$ —	$ —	$ 34.6
International [b]	163.7	120.4	—	—	43.3
Real estate [c]	42.7	12.4	—	—	30.3
Commodities [d]	14.1	—	—	—	14.1
Fixed income securities					
Fixed income funds [e]	65.1	20.9	—	—	44.2
U.S. Treasury	52.2	52.2	—	—	—
U.S. Agency, state and local obligations	17.9	—	17.9	—	—
U.S. corporate bonds [f]	120.2	—	120.2	—	—
Foreign corporate bonds	9.3	—	9.3	—	—
Hedge funds [g]	15.6	—	—	—	15.6
Cash equivalents	31.7	31.7	—	—	—
Other	(3.3)	—	(3.3)	—	—
Total	$ 776.8	$ 450.6	$ 144.1	$ —	$ 182.1

Description	December 31 2015	Fair Value Measurements Using			
		Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Assets measured at NAV
Pension Plans			(millions)		
Equity securities					
U.S. [a]	$ 226.0	$ 195.5	$ —	$ —	$ 30.5
International [b]	147.4	109.7	—	—	37.7
Real estate [c]	45.9	12.2	—	—	33.7
Commodities [d]	5.8	—	—	—	5.8
Fixed income securities					
Fixed income funds [e]	60.4	20.0	—	—	40.4
U.S. Treasury	48.8	48.8	—	—	—
U.S. Agency, state and local obligations	19.0	—	19.0	—	—
U.S. corporate bonds [f]	108.8	—	108.8	—	—
Foreign corporate bonds	10.2	—	10.2	—	—
Hedge funds [g]	23.7	—	—	—	23.7
Cash equivalents	26.0	26.0	—	—	—
Other	1.9	—	1.9	—	—
Total	$ 723.9	$ 412.2	$ 139.9	$ —	$ 171.8

[a] At December 31, 2016 and 2015, this category is comprised of $128.8 million and $121.6 million, respectively, of traded mutual funds valued at daily listed prices and $84.2 million and $73.9 million, respectively, of traded common stocks and exchange traded funds. At December 31, 2016 and 2015, this category also includes $34.6 million and $30.5 million, respectively, of institutional common/collective trust funds valued at net asset value (NAV) per share (or its equivalent) and is not categorized in the fair value hierarchy.

[b] At December 31, 2016 and 2015, this category is comprised of $92.8 million and $34.2 million, respectively, of traded mutual funds valued at daily listed prices and $27.6 million and $75.5 million, respectively, of traded American depository receipts, global depository receipts and ordinary shares. At December 31, 2016 and 2015, this category also includes $43.3 million and $37.7 million, respectively, of institutional common/collective trust funds valued at NAV per share (or its equivalent) and is not categorized in the fair value hierarchy.

[c] At December 31, 2016 and 2015, this category is comprised of $12.4 million and $12.2 million, respectively, of traded real estate investment trusts. At December 31, 2016 and 2015, this category also includes $30.3 million and $33.7 million, respectively, of institutional common/collective trust funds and a limited partnership valued at NAV per share (or its equivalent) and is not categorized in the fair value hierarchy.

[d] Consists of institutional common/collective trust funds valued at NAV per share (or its equivalent) and is not categorized in the fair value hierarchy.

[e] At December 31, 2016 and 2015, this category is comprised of $20.9 million and $20.0 million, respectively, of traded mutual funds valued at daily listed prices. At December 31, 2016 and 2015, this category also includes $44.2 million and $40.4 million, respectively, of institutional common/collective trust funds valued at NAV per share (or its equivalent) and is not categorized in the fair value hierarchy.

[f] At December 31, 2016 and 2015, this category is comprised of $115.7 million and $103.0 million, respectively, of corporate bonds, $2.3 million and $2.9 million, respectively, of collateralized mortgage obligations and $2.2 million and $2.9 million, respectively, of other asset-backed securities.

[g] Consists of closely-held limited partnerships valued at NAV per share (or its equivalent) and is not categorized in the fair value hierarchy.

Other post-retirement plan assets are also managed in accordance with prudent investor guidelines contained in the ERISA requirements. The investment strategy supports the objective of the funds, which is to preserve capital, maintain sufficient liquidity and earn a consistent rate of return. Other post-retirement plan assets are invested primarily in fixed income securities, which may include domestic and foreign corporate bonds, collateralized mortgage obligations and asset-backed securities, U.S. government agency, state and local obligations, U.S. Treasury notes and money market funds, as well as domestic and international equity funds.

The fair values of Great Plains Energy's other post-retirement plan assets at December 31, 2016 and 2015, by asset category are in the following tables.

		Fair Value Measurements Using			
Description	**December 31 2016**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Assets measured at NAV**
Other Post-Retirement Benefit Plans			(millions)		
Equity securities	$ 4.1	$ 4.1	$ —	$ —	$ —
Fixed income securities					
Fixed income fund[(a)]	62.7	—	—	—	62.7
U.S. Treasury	3.9	3.9	—	—	—
U.S. Agency, state and local obligations	4.3	—	4.3	—	—
U.S. corporate bonds[(b)]	17.8	—	17.8	—	—
Foreign corporate bonds	1.6	—	1.6	—	—
Cash equivalents	19.5	19.5	—	—	—
Other	1.7	0.2	1.5	—	—
Total	$ 115.6	$ 27.7	$ 25.2	$ —	$ 62.7

		Fair Value Measurements Using			
Description	**December 31 2015**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Assets measured at NAV**
Other Post-Retirement Benefit Plans			(millions)		
Equity securities	$ 3.2	$ 3.2	$ —	$ —	$ —
Fixed income securities					
Fixed income fund[(a)]	68.9	0.1	—	—	68.8
U.S. Treasury	3.9	3.9	—	—	—
U.S. Agency, state and local obligations	5.4	—	5.4	—	—
U.S. corporate bonds[(b)]	15.6	—	15.6	—	—
Foreign corporate bonds	1.6	—	1.6	—	—
Cash equivalents	14.0	14.0	—	—	—
Other	1.7	—	1.7	—	—
Total	$ 114.3	$ 21.2	$ 24.3	$ —	$ 68.8

(a) At December 31, 2015, this category is comprised of $0.1 million of traded mutual funds valued at daily listed prices. At December 31, 2016 and 2015, this category also includes $62.7 million and $68.8 million, respectively, of an institutional common/collective trust fund valued at NAV per share (or its equivalent) and is not categorized in the fair value hierarchy.

(b) At December 31, 2016 and 2015, this category is comprised of $14.0 million and $12.6 million, respectively, of corporate bonds, $0.5 million and $0.6 million, respectively, of collateralized mortgage obligations and $3.3 million and $2.4 million, respectively, of other asset-backed securities.

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. The cost trend assumed for 2016 and 2017 was 6.8% and 6.5%, respectively, with the rate declining through 2025 to the ultimate cost trend rate of 4.5%.

The effects of a one-percentage point change in the assumed health care cost trend rates, holding all other assumptions constant, at December 31, 2016, are detailed in the following table.

	Increase	Decrease
	(millions)	
Effect on total service and interest component	$ 0.8	$ (0.7)
Effect on post-retirement benefit obligation	1.0	(0.8)

Employee Savings Plans
Great Plains Energy has defined contribution savings plans (401(k)) that cover substantially all employees. Great Plains Energy matches employee contributions, subject to limits. The annual cost of the plans was approximately $11.5 million in 2016, $10.6 million in 2015 and $9.7 million in 2014. KCP&L's annual cost of the plans was approximately $8.0 million in 2016, $7.9 million in 2015 and $7.1 million in 2014.

10. EQUITY COMPENSATION

Great Plains Energy's Long-Term Incentive Plan is an equity compensation plan approved by Great Plains Energy's shareholders. The Long-Term Incentive Plan permits the grant of restricted stock, restricted stock units, bonus shares, stock options, stock appreciation rights, limited stock appreciation rights, director shares, director deferred share units and performance shares to directors, officers and other employees of Great Plains Energy and KCP&L. The maximum number of shares of Great Plains Energy common stock that can be issued under the plan is 8.0 million. Common stock shares delivered by Great Plains Energy under the Long-Term Incentive Plan may be authorized but unissued, held in the treasury or purchased on the open market (including private purchases) in accordance with applicable securities laws. Great Plains Energy has a policy of delivering newly issued shares, or shares surrendered by Long-Term Incentive Plan participants for the withholding of taxes and held in treasury, or both, and does not expect to repurchase common shares during 2017 to satisfy performance share payments and director deferred share unit conversion. Forfeiture rates are based on historical forfeitures and future expectations and are reevaluated annually.

The following table summarizes Great Plains Energy's and KCP&L's equity compensation expense and the associated income tax benefit.

	2016	2015	2014
Great Plains Energy		(millions)	
Equity compensation expense	$ 5.0	$ 4.0	$ 9.9
Income tax benefit	1.6	1.4	3.6
KCP&L			
Equity compensation expense	$ 3.2	$ 2.6	$ 6.9
Income tax benefit	1.0	0.9	2.4

Performance Shares
The payment of performance shares is contingent upon achievement of specific performance goals over a stated period of time as approved by the Compensation and Development Committee of the Board. The number of performance shares ultimately paid can vary from the number of shares initially granted depending on Great Plains Energy's performance over stated performance periods. Compensation expense for performance shares is calculated by recognizing the portion of the fair value for each reporting period for which the requisite service has been rendered. Dividends are accrued over the vesting period and paid in cash based on the number of performance shares ultimately paid.

The fair value of performance share awards is estimated using the market value of the Company's stock at the valuation date and a Monte Carlo simulation technique that incorporates assumptions for inputs of expected volatilities, dividend yield and risk-free rates. Expected volatility is based on daily stock price change during a historical period commensurate with the remaining term of the performance period of the grant. The risk-free rate is based upon the rate at the time of the evaluation for zero-coupon government bonds with a maturity consistent with the remaining performance period of the grant. The dividend yield is based on the most recent dividends paid and the actual closing stock price on the valuation date. For shares granted in 2016, inputs for expected volatility, dividend yield and risk-free rates were 18%, 3.61% and 0.94%, respectively.

Performance share activity is summarized in the following table. Performance adjustment represents the number of shares of common stock related to performance shares ultimately issued that can vary from the number of performance shares initially granted depending on Great Plains Energy's performance over a stated period of time.

	Performance Shares	**Grant Date Fair Value***
Beginning balance January 1, 2016	609,010	$ 25.60
Granted	225,204	31.41
Earned	(306,953)	24.22
Forfeited	(1,714)	27.61
Performance adjustment	99,553	24.16
Ending balance December 31, 2016	625,100	28.13

* weighted-average

At December 31, 2016, the remaining weighted-average contractual term was 1.1 years. The weighted-average grant-date fair value of shares granted was $31.41, $24.03 and $28.78 in 2016, 2015 and 2014, respectively. At December 31, 2016, there was $6.4 million of total unrecognized compensation expense, net of forfeiture rates, related to performance shares granted under the Long-Term Incentive Plan, which will be recognized over the remaining weighted-average contractual term. The total fair value of performance shares earned and paid was $7.4 million, $0.5 million and $2.8 million in 2016, 2015 and 2014, respectively.

Restricted Stock

Restricted stock cannot be sold or otherwise transferred by the recipient prior to vesting and has a value equal to the fair market value of the shares on the issue date. Restricted stock shares vest over a stated period of time with accruing reinvested dividends subject to the same restrictions. Compensation expense, calculated by multiplying shares by the grant-date fair value related to restricted stock, is recognized over the stated vesting period. Restricted stock activity is summarized in the following table.

	Nonvested Restricted Stock	**Grant Date Fair Value***
Beginning balance January 1, 2016	231,508	$ 24.78
Granted and issued	96,053	29.41
Vested	(77,317)	22.69
Forfeited	(572)	27.51
Ending balance December 31, 2016	249,672	27.20

* weighted-average

At December 31, 2016, the remaining weighted-average contractual term was 1.2 years. The weighted-average grant-date fair value of shares granted was $29.41, $25.89 and $25.70 in 2016, 2015 and 2014, respectively. At December 31, 2016, there was $2.6 million of total unrecognized compensation expense, net of forfeiture rates, related to nonvested restricted stock granted under the Long-Term Incentive Plan, which will be recognized over the remaining weighted-average contractual term. Total fair value of shares vested was $1.8 million, $2.2 million and $1.9 million in 2016, 2015 and 2014, respectively.

Director Deferred Share Units

Non-employee directors receive shares of Great Plains Energy's common stock as part of their annual retainer. Each director may elect to defer receipt of their shares by receiving Director Deferred Share Units that convert to shares of Great Plains Energy's common stock at the end of January in the year after departure from the Board or such other time as elected by each director. Director Deferred Share Units have a value equal to the market value of Great Plains Energy's common stock on the grant date with accruing dividends. Compensation expense, calculated by multiplying the director deferred share units by the related grant-date fair value, is recognized at the grant date. The total fair value of shares of Director Deferred Share Units issued was insignificant for 2016 and 2015. Director Deferred Share Units activity is summarized in the following table.

	Share Units	Grant Date Fair Value*
Beginning balance January 1, 2016	115,415	$ 22.95
Issued	23,172	28.99
Ending balance December 31, 2016	138,587	23.96

* weighted-average

11. SHORT-TERM BORROWINGS AND SHORT-TERM BANK LINES OF CREDIT

Great Plains Energy's $200 Million Revolving Credit Facility
Great Plains Energy's $200 million revolving credit facility with a group of banks expires in October 2019. The facility's terms permit transfers of unused commitments between this facility and the KCP&L and GMO facilities discussed below, with the total amount of the facility not exceeding $400 million at any one time. A default by Great Plains Energy or any of its significant subsidiaries on other indebtedness totaling more than $50.0 million is a default under the facility. Under the terms of this facility, Great Plains Energy is required to maintain a consolidated indebtedness to consolidated capitalization ratio, as defined in the facility, not greater than 0.65 to 1.00 at all times. At December 31, 2016, Great Plains Energy was in compliance with this covenant. In June 2016, the facility was amended, among other things, to increase the maximum consolidated indebtedness to consolidated capitalization ratio of 0.65 to 1.00 to a level such that, if Great Plains Energy would not be in compliance with the covenant as of the date of the closing of the anticipated acquisition of Westar, the ratio would increase up to a maximum of 0.75 to 1.00 for one year. At December 31, 2016, Great Plains Energy had no outstanding cash borrowings and had issued $1.0 million in letters of credit under the credit facility. At December 31, 2015, Great Plains Energy had $10.0 million of outstanding cash borrowings at a weighted-average interest rate of 1.94% and had issued $0.2 million letters of credit under the credit facility.

KCP&L's $600 Million Revolving Credit Facility and Commercial Paper
KCP&L's $600 million revolving credit facility with a group of banks provides support for its issuance of commercial paper and other general corporate purposes and expires in October 2019. Great Plains Energy and KCP&L may transfer up to $200 million of unused commitments between Great Plains Energy's and KCP&L's facilities. A default by KCP&L on other indebtedness totaling more than $50.0 million is a default under the facility. Under the terms of this facility, KCP&L is required to maintain a consolidated indebtedness to consolidated capitalization ratio, as defined in the facility, not greater than 0.65 to 1.00 at all times. At December 31, 2016, KCP&L was in compliance with this covenant. At December 31, 2016, KCP&L had $132.9 million of commercial paper outstanding at a weighted-average interest rate of 0.98%, had issued letters of credit totaling $2.8 million and had no outstanding cash borrowings under the credit facility. At December 31, 2015, KCP&L had $180.3 million of commercial paper outstanding at a weighted-average interest rate of 0.70%, had issued letters of credit totaling $2.7 million and had no outstanding cash borrowings under the credit facility.

GMO's $450 Million Revolving Credit Facility and Commercial Paper
GMO's $450 million revolving credit facility with a group of banks provides support for its issuance of commercial paper and other general corporate purposes and expires in October 2019. Great Plains Energy and GMO may transfer up to $200 million of unused commitments between Great Plains Energy's and GMO's facilities. A default by GMO or any of its significant subsidiaries on other indebtedness totaling more than $50.0 million is a default under the facility. Under the terms of this facility, GMO is required to maintain a consolidated indebtedness to consolidated capitalization ratio, as defined in the facility, not greater than 0.65 to 1.00 at all times. At December 31, 2016, GMO was in compliance with this covenant. At December 31, 2016, GMO had $201.9 million of commercial paper outstanding at a weighted-average interest rate of 1.02%, had issued letters of credit totaling

$1.9 million and had no outstanding cash borrowings under the credit facility. At December 31, 2015, GMO had $43.7 million of commercial paper outstanding at a weighted-average interest rate of 0.65%, had issued letters of credit totaling $2.5 million and had no outstanding cash borrowings under the credit facility.

Great Plains Energy's $5.1 Billion Term Loan Facility

In connection with the Merger Agreement, Great Plains Energy entered into a commitment letter for a 364-day senior unsecured bridge term loan facility, originally for an aggregate principal amount of $8.017 billion to support the anticipated transaction and provide flexibility for the timing of long-term financing. The aggregate principal amount of the facility has been reduced most recently in connection with the October 2016 Great Plains Energy common stock and depositary share offerings. As of December 31, 2016, the available aggregate principal amount of the facility was $5.1 billion.

12. LONG-TERM DEBT

Great Plains Energy's and KCP&L's long-term debt is detailed in the following table.

	Year Due	December 31 2016	December 31 2015
KCP&L		(millions)	
General Mortgage Bonds			
2.47% EIRR bonds[(a)]	2017-2035	$ 110.5	$ 110.5
7.15% Series 2009A (8.59% rate)[(b)]	2019	400.0	400.0
Senior Notes			
5.85% Series (5.72% rate)[(b)]	2017	250.0	250.0
6.375% Series (7.49% rate)[(b)]	2018	350.0	350.0
3.15% Series	2023	300.0	300.0
3.65% Series	2025	350.0	350.0
6.05% Series (5.78% rate)[(b)]	2035	250.0	250.0
5.30% Series	2041	400.0	400.0
EIRR Bonds			
0.694% Series 2007A and 2007B[(c)]	2035	146.5	146.5
2.875% Series 2008	2038	23.4	23.4
Current maturities		(281.0)	—
Unamortized discount and debt issuance costs		(15.4)	(17.3)
Total KCP&L excluding current maturities[(d)]		2,284.0	2,563.1
Other Great Plains Energy			
GMO First Mortgage Bonds 9.44% Series	2017-2021	5.7	6.8
GMO Senior Notes			
8.27% Series	2021	80.9	80.9
3.49% Series A	2025	125.0	125.0
4.06% Series B	2033	75.0	75.0
4.74% Series C	2043	150.0	150.0
GMO Medium Term Notes			
7.33% Series	2023	3.0	3.0
7.17% Series	2023	7.0	7.0
Great Plains Energy Senior Notes			
6.875% Series (7.33% rate)[(b)]	2017	100.0	100.0
4.85% Series	2021	350.0	350.0
5.292% Series	2022	287.5	287.5
Current maturities		(101.1)	(1.1)
Unamortized discount and premium, net and debt issuance costs		(1.8)	(2.1)
Total Great Plains Energy excluding current maturities[(d)]		$ 3,365.2	$ 3,745.1

(a) Weighted-average interest rates at December 31, 2016

(b) Rate after amortizing gains/losses recognized in other comprehensive income (OCI) on settlements of interest rate hedging instruments

(c) Variable rate

(d) At December 31, 2016 and 2015, does not include $50.0 million and $21.9 million of secured Series 2005 Environmental Improvement Revenue Refunding (EIRR) bonds because the bonds were repurchased in September 2015 and are held by KCP&L

Amortization of Debt Expense
Great Plains Energy's and KCP&L's amortization of debt expense is detailed in the following table.

	2016	2015	2014
		(millions)	
KCP&L	$ 3.2	$ 3.0	$ 3.0
Other Great Plains Energy	30.6	1.1	1.8
Total Great Plains Energy	$ 33.8	$ 4.1	$ 4.8

In 2016, Other Great Plains Energy includes $29.6 million of amortization of debt expense related to Great Plains Energy's $5.1 billion bridge term loan facility. Fees related to this facility are being amortized over the 364 day term of the facility.

KCP&L General Mortgage Bonds
KCP&L has issued mortgage bonds under the General Mortgage Indenture and Deed of Trust dated December 1, 1986, as supplemented (Indenture). The Indenture creates a mortgage lien on substantially all of KCP&L's utility plant. Mortgage bonds totaling $510.5 million were outstanding at December 31, 2016 and 2015, respectively.

KCP&L Municipal Bond Insurance Policies
KCP&L's secured Series 2005 EIRR bonds totaling $50.0 million and $21.9 million, respectively, are covered by a municipal bond insurance policy between KCP&L and Syncora Guarantee, Inc. (Syncora). The insurance agreements between KCP&L and Syncora provide for reimbursement by KCP&L for any amounts that Syncora pays under the municipal bond insurance policies. The insurance agreements contain a covenant that the indebtedness to total capitalization ratio of KCP&L and its consolidated subsidiaries will not be greater than 0.68 to 1.00. At December 31, 2016, KCP&L was in compliance with this covenant. KCP&L is also restricted from issuing additional bonds under its General Mortgage Indenture if, after giving effect to such additional bonds, the proportion of secured debt to total indebtedness would be more than 75%, or more than 50% if the long term rating for such bonds by Standard & Poor's or Moody's Investors Service would be at or below A- or A3, respectively. The insurance agreement covering the unsecured Series 2005 EIRR bonds also required KCP&L to provide collateral to Syncora in the form of $50.0 million of Mortgage Bonds Series 2005 EIRR Insurer due 2035 for KCP&L's obligations under the insurance agreement as a result of KCP&L issuing general mortgage bonds in 2009 (other than refunding of outstanding general mortgage bonds) that resulted in the aggregate amount of outstanding general mortgage bonds exceeding 10% of total capitalization. The bonds are not incremental debt for KCP&L but collateralize Syncora's claim on KCP&L if Syncora was required to meet its obligation under the insurance agreement. In the event of a default under the insurance agreements, Syncora may take any available legal or equitable action against KCP&L, including seeking specific performance of the covenants.

GMO First Mortgage Bonds
GMO has issued mortgage bonds under the General Mortgage Indenture and Deed of Trust dated April 1, 1946, as supplemented. The Indenture creates a mortgage lien on a portion of GMO's utility plant. Mortgage bonds totaling $5.7 million and $6.8 million, respectively, were outstanding at December 31, 2016 and 2015.

GMO Senior Notes
Under the terms of the note purchase agreement for GMO's Series A, B and C Senior Notes, GMO is required to maintain a consolidated indebtedness to consolidated capitalization ratio, as defined in the agreement, not greater than 0.65 to 1.00 at all times. In addition, GMO's priority debt, as defined in the agreement, cannot exceed 15% of consolidated tangible net worth, as defined in the agreement. At December 31, 2016, GMO was in compliance with these covenants.

Scheduled Maturities

Great Plains Energy's and KCP&L's long-term debt maturities for the next five years are detailed in the following table.

	2017	2018	2019	2020	2021
			(millions)		
Great Plains Energy	$ 382.1	$ 351.1	$ 401.1	$ 1.1	$ 432.0
KCP&L	281.0	350.0	400.0	—	—

13. COMMON STOCK

Great Plains Energy has an effective shelf registration statement for the sale of unlimited amounts of securities with the SEC that became effective in March 2015 and expires in March 2018. In September 2016, Great Plains Energy filed a post-effective amendment to its shelf registration statement to register depositary shares and preference stock among the types of securities that Great Plains Energy may offer and sell.

In September 2016, Great Plains Energy shareholders approved an amendment to Great Plains Energy's articles of incorporation, increasing the authorized number of shares of common stock, without par value, to 600 million shares from 250 million shares.

In October 2016, Great Plains Energy completed a registered public offering of 60.5 million shares of common stock, without par value, at a public offering price of $26.45 per share, for total gross proceeds of approximately $1.6 billion (net proceeds of approximately $1.55 billion after issuance costs). Great Plains Energy plans to use proceeds from the offering to finance a portion of the cash consideration for the anticipated acquisition of Westar.

Great Plains Energy has shares of common stock registered with the SEC for its Dividend Reinvestment and Direct Stock Purchase Plan. The plan allows for the purchase of common shares by reinvesting dividends or making optional cash payments. Great Plains Energy can issue new shares or purchase shares on the open market for the plan. At December 31, 2016, 1.0 million shares remained available for future issuances.

Great Plains Energy has shares of common stock registered with the SEC for a defined contribution savings plan (401(k)). Shares issued under the plan may be either newly issued shares or shares purchased in the open market. At December 31, 2016, 0.7 million shares remained available for future issuances.

Treasury shares are held for future distribution upon issuance of shares in conjunction with the Company's Long-Term Incentive Plan.

Great Plains Energy's articles of incorporation restrict the payment of common stock dividends in the event common equity is 25% or less of total capitalization. In addition, if preferred stock dividends are not declared and paid when scheduled, Great Plains Energy could not declare or pay common stock dividends or purchase any common shares. If the unpaid preferred stock dividends are in arrears for six or more quarters, whether or not consecutive, the preferred shareholders will be entitled to name two directors to the Great Plains Energy Board. Certain conditions in the MPSC and KCC orders authorizing the holding company structure require Great Plains Energy and KCP&L to maintain consolidated common equity of at least 30% and 35%, respectively, of total capitalization (including only the amount of short-term debt in excess of the amount of construction work in progress). Under the Federal Power Act, KCP&L and GMO generally can pay dividends only out of retained earnings. The revolving credit agreements of Great Plains Energy, KCP&L and GMO and the note purchase agreement for GMO's Series A, B and C Senior Notes contain a covenant requiring the respective company to maintain a consolidated indebtedness to consolidated total capitalization ratio of not more than 0.65 to 1.00 at all times, except as the ratio pertains to Great Plains Energy, which was amended in June 2016, as further described in Note 11.

As of December 31, 2016, all of Great Plains Energy's and KCP&L's retained earnings and net income were free of restrictions. As a result of the above restrictions, Great Plains Energy's subsidiaries had restricted net assets of approximately $2.8 billion as of December 31, 2016. The restrictions are not expected to affect the Companies' ability to pay dividends at the current level in the foreseeable future.

14. PREFERRED STOCK

At December 31, 2016, 1.6 million shares of Cumulative No Par Preferred Stock, 390,000 shares of Cumulative Preferred Stock, $100 par value and 11.0 million shares of Preference Stock without par value were authorized under Great Plains Energy's articles of incorporation.

At December 31, 2016, Great Plains Energy had 862,500 shares of Series B Preferred Stock issued and outstanding and had entered into a stock purchase agreement to issue 750,000 shares of Series A Preferred Stock at the closing of the anticipated acquisition with Westar. In August 2016, Great Plains Energy redeemed its 390,000 shares of outstanding Cumulative Preferred Stock, $100 par value. See the discussion below for further information on these transactions and the pertinent rights and privileges of the Series A and Series B Preferred Stock.

Series A Mandatory Convertible Preferred Stock

On May 29, 2016, Great Plains Energy entered into a stock purchase agreement with OMERS, pursuant to which Great Plains Energy will issue and sell to OMERS 750,000 shares of Series A Preferred Stock, for an aggregate purchase price equal to $750 million at the closing of the merger. The stock purchase agreement is subject to various closing conditions.

Each share of Series A Preferred Stock shall automatically convert three years after issuance into a number of shares of Great Plains Energy common stock equal to the Conversion Rate.

The Conversion Rate is calculated as follows:

If the average volume-weighted average price per share of Great Plains Energy common stock over 20 consecutive trading days commencing on the 22nd trading day prior to the date of conversion (Applicable Market Value) is:

(a) Equal to or greater than $34.38, the Conversion Rate shall be 29.0855;
(b) Less than $34.38 but greater than $28.65, the Conversion Rate shall be $1,000 divided by the Applicable Market Value; or
(c) Less than or equal to $28.65, the Conversion Rate shall be 34.9026.

OMERS can voluntarily convert its Series A Preferred Stock into Great Plains Energy common stock at any time at the 29.0855 Conversion Rate, subject to obtaining all necessary governmental approvals.

The Series A Preferred Stock is entitled to a 7.25% annual dividend, payable in cash, Great Plains Energy common stock or a combination thereof. The Series A Preferred Stock has a liquidation preference of $1,000 per share.

OMERS will be entitled to name two directors to the Great Plains Energy Board if dividends payable with respect to the Series A Preferred Stock are in arrears for two quarters and one observer on the Great Plains Energy Board if Great Plains Energy's credit rating is downgraded to below investment grade, so long as OMERS holds 50 percent of its original investment and subject to all necessary governmental approvals being obtained.

Series B Mandatory Convertible Preferred Stock

In October 2016, Great Plains Energy completed a registered public offering of 17.3 million depositary shares, each representing a 1/20th interest in a share of Great Plains Energy's Series B Preferred Stock, without par value, at a public offering price of $50 per depositary share for total gross proceeds of $862.5 million (net proceeds of approximately $836.2 million after issuance costs). Great Plains Energy plans to use proceeds from the offering to fund a portion of the cash consideration for the anticipated acquisition of Westar.

Each depositary share entitles the holder of such depositary share, through the bank depositary, to a 1/20th interest in the rights and preferences of the Series B Preferred Stock, including conversion, dividend, liquidation and voting rights, subject to the terms of the deposit agreement.

Unless previously converted or redeemed, on or around September 15, 2019, each outstanding share of Series B Preferred Stock will automatically convert into a number of shares of Great Plains Energy common stock equal to the Conversion Rate.

The Conversion Rate is calculated as follows:

If the volume-weighted average price per share, subject to certain anti-dilution adjustments, of Great Plains Energy common stock over 20 consecutive trading days commencing on the 22nd trading day prior to the date of conversion (Applicable Market Value) is:

(a) Equal to or greater than $31.74, the Conversion Rate shall be 31.5060;
(b) Less than $31.74 but greater than $26.45, the Conversion Rate shall be $1,000 divided by the Applicable Market Value; or
(c) Less than or equal to $26.45, the Conversion Rate shall be 37.8080.

At any time prior to September 15, 2019, a holder may elect to convert shares of the Series B Preferred Stock in whole or in part (but not less than one share of Series B Preferred Stock) into shares of Great Plains Energy common stock at the 31.5060 Conversion Rate.

Dividends on the Series B Preferred Stock will be payable on a cumulative basis when, as and if declared by Great Plains Energy's Board of Directors, and subject to Missouri law, at an annual rate of 7.00% on the liquidation preference of $1,000 per share of Series B Preferred Stock (or $50 per depositary share), payable in cash, Great Plains Energy common stock or a combination thereof.

Holders of the Series B Preferred Stock will be entitled to name two directors to the Great Plains Energy Board if dividends payable with respect to the Series B Preferred Stock are in arrears for six or more quarters, whether or not consecutive.

Cumulative Preferred Stock
In August 2016, Great Plains Energy redeemed its 390,000 shares of outstanding Cumulative Preferred Stock, par value $100 per share, for a total redemption price of $40.1 million. Great Plains Energy redeemed all outstanding shares of its (i) 3.80% Preferred for $103.70 per share, plus accrued and unpaid dividends of $0.75 per share, for a total redemption price of $104.45 per share, (ii) 4.50% Preferred for $101.00 per share, plus accrued and unpaid dividends of $0.89 per share, for a total redemption price of $101.89 per share, (iii) 4.20% Preferred for $102.00 per share, plus accrued and unpaid dividends of $0.83 per share, for a total redemption price of $102.83 per share and (iv) 4.35% Preferred for $101.00 per share, plus accrued and unpaid dividends of $0.86 per share, for a total redemption price of $101.86 per share.

15. COMMITMENTS AND CONTINGENCIES

Environmental Matters
Great Plains Energy and KCP&L are subject to extensive federal, state and local environmental laws, regulations and permit requirements relating to air and water quality, waste management and disposal, natural resources and health and safety. In addition to imposing continuing compliance obligations and remediation costs, these laws, regulations and permits authorize the imposition of substantial penalties for noncompliance, including fines, injunctive relief and other sanctions. The cost of complying with current and future environmental requirements is expected to be material to Great Plains Energy and KCP&L. Failure to comply with environmental requirements or to timely recover environmental costs through rates could have a material effect on Great Plains Energy's and KCP&L's results of operations, financial position and cash flows.

Great Plains Energy's and KCP&L's current estimates of capital expenditures (exclusive of AFUDC and property taxes) over the next four years to comply with environmental regulations are in the following table. The total cost of compliance with any existing, proposed or future laws and regulations may be significantly different from these cost estimates provided.

	2017	2018	2019	2020
	(millions)			
Great Plains Energy	$ 43.4	$ 36.6	$ 11.5	$ 14.0
KCP&L	34.9	16.5	7.6	13.0

The Companies expect to seek recovery of the costs associated with environmental requirements through rate increases; however, there can be no assurance that such rate increases would be granted. The Companies may be subject to materially adverse rate treatment in response to competitive, economic, political, legislative or regulatory factors and/or public perception of the Companies' environmental reputation.

The following discussion groups environmental and certain associated matters into the broad categories of air and climate change, water, solid waste and remediation.

Clean Air Act and Climate Change Overview

The Clean Air Act Amendments of 1990 (Clean Air Act) and associated regulations enacted by the Environmental Protection Agency (EPA) form a comprehensive program to preserve and enhance air quality. States are required to establish regulations and programs to address all requirements of the Clean Air Act and have the flexibility to enact more stringent requirements. All of Great Plains Energy's and KCP&L's generating facilities, and certain of their other facilities, are subject to the Clean Air Act.

Climate Change

The Companies' current generation capacity is primarily coal-fired and is estimated to produce about one ton of carbon dioxide (CO_2) per MWh, or approximately 19 million tons and 15 million tons per year for Great Plains Energy and KCP&L, respectively. The Companies are subject to existing greenhouse gas reporting regulations and certain greenhouse gas requirements. Federal or state legislation concerning the reduction of emissions of greenhouse gases, including CO_2, could be enacted in the future. At the international level, in December 2015 the Paris Agreement was adopted by nearly 200 countries and became effective in November 2016 as the threshold of at least 55 countries representing at least 55% of global greenhouse gas emissions have joined it through ratification. The Paris Agreement does not result in any new, legally binding obligations on the United States to meet a particular greenhouse gas emissions target, but establishes a framework for international cooperation on climate change. Other international agreements legally binding on the United States may be reached in the future. Greenhouse gas legislation has the potential of having significant financial and operational impacts on Great Plains Energy and KCP&L; however, the ultimate financial and operational consequences to Great Plains Energy and KCP&L cannot be determined until such legislation is passed. In the absence of new Congressional mandates, the EPA is proceeding with the regulation of greenhouse gases under the existing Clean Air Act.

In August 2015, the EPA finalized CO_2 emission standards for new, modified and reconstructed affected fossil-fuel-fired electric utility generating units. The standards would not apply to Great Plains Energy's and KCP&L's existing units unless the units were modified or reconstructed in the future.

In August 2015, the EPA finalized its Clean Power Plan which sets CO_2 emission performance rates for existing affected fossil fuel-fired electric generating units. Specifically, the EPA translated those performance rates into a state goal measured in mass and rate based on each state's generation mix. The states have the ability to develop their own plans for affected units to achieve either the performance rates directly or the state goals, with guidelines for the development, submittal and implementation of those plans. Nationwide, by 2030, the EPA projects the Clean Power Plan would achieve CO_2 emission reductions from the power sector of approximately 32% from CO_2 emission levels in 2005.

The EPA has finalized an interim CO_2 goal rate reduction in Kansas and Missouri (average of 2022-2029) of 34% and 26%, respectively, and 2030 targets in Kansas and Missouri of 44% and 37%, respectively. The baseline for these reductions is 2012 CO_2 emissions adjusted by the EPA. The EPA has also finalized mass based CO_2 reduction goals.

States are required to submit plans to implement the Clean Power Plan. An EPA plan with either a rate-based or mass-based trading program has yet to be finalized and can be enforced in states that fail to submit approved plans.

In February 2016, the U.S. Supreme Court granted a stay of the Clean Power Plan putting the rule on hold pending review in the United States Court of Appeals for the District of Columbia Circuit and any subsequent review by the U.S. Supreme Court if such review is sought. Compliance with the Clean Power Plan has the potential of having significant financial and operational impacts on Great Plains Energy and KCP&L; however, the ultimate financial and operational consequences to Great Plains Energy and KCP&L cannot be determined until the outcome of pending litigation is known and/or the state plans to implement the Clean Power Plan are known.

Clean Water Act

The Clean Water Act and associated regulations enacted by the EPA form a comprehensive program to restore and preserve water quality. Like the Clean Air Act, states are required to establish regulations and programs to address all requirements of the Clean Water Act, and have the flexibility to enact more stringent requirements. All of Great Plains Energy's and KCP&L's generating facilities, and certain of their other facilities, are subject to the Clean Water Act.

In May 2014, the EPA finalized regulations pursuant to Section 316(b) of the Clean Water Act regarding cooling water intake structures pursuant to a court approved settlement. KCP&L generation facilities with cooling water intake structures are subject to the best technology available standards based on studies completed to comply with such standards. The rule provides flexibility to work with the states to develop the best technology available to minimize aquatic species impacted by being pinned against intake screens (impingement) or drawn into cooling water systems (entrainment). Estimated costs to comply with Section 316(b) of the Clean Water Act are included in the estimated capital expenditures table above.

KCP&L holds a permit from the Missouri Department of Natural Resources (MDNR) covering water discharge from its Hawthorn Station. The permit authorizes KCP&L to, among other things, withdraw water from the Missouri River for cooling purposes and return the heated water to the Missouri River. KCP&L has applied for a renewal of this permit and the EPA has submitted an interim objection letter regarding the allowable amount of heat that can be contained in the returned water. Until this matter is resolved, KCP&L continues to operate under its current permit. Future water permit renewals at KCP&L's Iatan Station and at GMO's Sibley and Lake Road Stations could also be impacted by the allowable amount of heat that can be contained in the returned water. Great Plains Energy and KCP&L cannot predict the outcome of these matters; however, while less significant outcomes are possible, these matters may require a reduction in generation, installation of cooling towers or other technology to cool the water, or both, any of which could have a significant impact on Great Plains Energy's and KCP&L's results of operations, financial position and cash flows.

In September 2015, the EPA finalized a revision of the technology-based effluent limitations guidelines and standards regulation to make the existing controls on discharges from steam electric power plants more stringent. The final rule sets the first federal limits on the levels of toxic metals in wastewater that can be discharged from power plants. The new requirements for existing power plants would be phased in between 2018 and 2023. The final rule establishes new or additional requirements for wastewaters associated with the following processes and byproducts at certain KCP&L and GMO stations: flue gas desulfurization, fly ash, bottom ash, flue gas mercury control, and combustion residual leachate from landfills and surface impoundments. Estimated capital costs to comply with the final rule are included in the estimated capital expenditures table above.

Solid Waste

Solid and hazardous waste generation, storage, transportation, treatment and disposal are regulated at the federal and state levels under various laws and regulations. In December 2014, the EPA finalized regulations to regulate CCRs under the Resource Conservation and Recovery Act (RCRA) subtitle D to address the risks from the disposal of CCRs generated from the combustion of coal at electric generating facilities. The Companies use coal in generating electricity and dispose of the CCRs in both on-site facilities and facilities owned by third parties. KCP&L's Iatan, La Cygne, and Montrose Stations and GMO's Sibley Station have on-site facilities affected by the rule. The rule requires periodic assessments; groundwater monitoring; location restrictions; design and operating requirements; recordkeeping and notifications; and closure, among other requirements, for CCR units. The rule was promulgated in the Federal Register on April 17, 2015, and became effective six months after promulgation with various obligations effective at specified times within the rule. Estimated capital costs to comply with the CCR rule are included in the estimated capital expenditures table above. Certain requirements of the rule would require Great Plains Energy or KCP&L to expedite or incur additional capital expenditures in the future.

Great Plains Energy and KCP&L have AROs on their balance sheets for closure and post-closure of ponds and landfills containing CCRs. Certain requirements of the rule could in the future require further evaluation of the expected method of compliance and refinement of assumptions underlying the cost estimates for closure and post-closure. Great Plains Energy's and KCP&L's AROs could increase from the amounts presently recorded.

Remediation

Certain federal and state laws, including the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), hold current and previous owners or operators of contaminated facilities and persons who arranged for the disposal or treatment of hazardous substances liable for the cost of investigation and cleanup. CERCLA and other laws also authorize the EPA and other agencies to issue orders compelling potentially responsible parties to clean up sites that are determined to present an actual or potential threat to human health or the environment. GMO retains some environmental liability for several operations and investments it no longer owns. In addition, GMO also owns, or has acquired liabilities from companies that once owned or operated, former manufactured gas plant (MGP) sites, which are subject to the supervision of the EPA and various state environmental agencies.

At December 31, 2016 and 2015, KCP&L had $0.3 million accrued for environmental remediation expenses, which covers ground water monitoring at a former MGP site. The amount accrued was established on an undiscounted basis and KCP&L does not currently have an estimated time frame over which the accrued amount may be paid.

In addition to the $0.3 million accrual above, at December 31, 2016 and 2015, Great Plains Energy had $1.4 million accrued for the future investigation and remediation of certain additional GMO identified MGP sites and retained liabilities. This estimate was based upon review of the potential costs associated with conducting investigative and remedial actions at identified sites, as well as the likelihood of whether such actions will be necessary. This estimate could change materially after further investigation, and could also be affected by the actions of environmental agencies and the financial viability of other potentially responsible parties; however, given the uncertainty of these items the possible loss or range of loss in excess of the amount accrued is not estimable.

GMO has pursued recovery of remediation costs from insurance carriers and other potentially responsible parties. As a result of a settlement with an insurance carrier, approximately $1.5 million in insurance proceeds less an annual deductible is available to GMO to recover qualified MGP remediation expenses. GMO would seek recovery of additional remediation costs and expenses through rate increases; however, there can be no assurance that such rate increases would be granted.

Contractual Commitments
Great Plains Energy's and KCP&L's expenses related to lease commitments are detailed in the following table.

	2016	2015	2014
		(millions)	
Great Plains Energy	$ 15.0	$ 16.8	$ 16.0
KCP&L	13.7	15.0	14.0

Great Plains Energy's and KCP&L's contractual commitments at December 31, 2016, excluding pensions and long-term debt, are detailed in the following tables.

Great Plains Energy

	2017	2018	2019	2020	2021	After 2021	Total
Lease commitments				(millions)			
Operating lease	$ 12.9	$ 11.0	$ 9.3	$ 9.7	$ 9.7	$ 110.5	$ 163.1
Capital lease	0.4	0.4	0.4	0.4	0.4	3.1	5.1
Purchase commitments							
Fuel	259.0	145.8	62.2	53.8	11.2	100.8	632.8
Power	47.3	47.3	47.3	47.3	47.4	462.2	698.8
Other	50.1	32.0	33.3	5.9	6.5	38.7	166.5
Total contractual commitments	$ 369.7	$ 236.5	$ 152.5	$ 117.1	$ 75.2	$ 715.3	$ 1,666.3

KCP&L

	2017	2018	2019	2020	2021	After 2021	Total
Lease commitments				(millions)			
Operating lease	$ 12.0	$ 11.0	$ 9.3	$ 9.7	$ 9.7	$ 110.5	$ 162.2
Capital lease	0.2	0.2	0.2	0.2	0.2	1.6	2.6
Purchase commitments							
Fuel	221.5	119.4	43.6	35.1	1.8	100.8	522.2
Power	34.8	34.8	34.8	34.8	34.9	324.9	499.0
Other	49.3	31.1	30.6	5.0	5.6	33.0	154.6
Total contractual commitments	$ 317.8	$ 196.5	$ 118.5	$ 84.8	$ 52.2	$ 570.8	$ 1,340.6

Great Plains Energy's and KCP&L's lease commitments end in 2048. Operating lease commitments include rail cars to serve jointly-owned generating units where KCP&L is the managing partner. Of the amounts included in the table above, KCP&L will be reimbursed by the other owners for approximately $1.5 million in 2017, $1.2 million in 2018 and approximately $0.4 million per year from 2019 to 2025, for a total of $5.5 million.

Fuel commitments consist of commitments for nuclear fuel, coal and coal transportation. Power commitments consist of commitments for renewable energy under power purchase agreements. Other represents individual commitments entered into in the ordinary course of business.

16. LEGAL PROCEEDINGS

GMO Western Energy Crisis

In response to complaints of excessive prices in the California energy markets, FERC issued an order in July 2001 requiring net sellers of power in the California markets from October 2, 2000, through June 20, 2001, at prices above a FERC-determined competitive market clearing price, to make refunds to net purchasers of power in the California market during that time period. Because MPS Merchant was a net purchaser of power during the refund period, it has received approximately $8 million in refunds through settlements with certain sellers of power. MPS Merchant estimates that it is entitled to approximately $12 million in additional refunds under the standards FERC has used in this case once a comprehensive resettlement of those markets occurs, as required by FERC. FERC has stated that interest will be applied to the refunds but the amount of interest has not yet been determined.

In November 2014, FERC issued an order finding that MPS Merchant engaged in tariff violations during the periods prior to October 2, 2000 (the Summer Period) and ordered refunds in the form of disgorgement of certain revenues. MPS Merchant (and other parties) filed a request for rehearing challenging FERC's findings of tariff violations and the remedy imposed in the November 2014 order. Additionally, several parties representing California utilities and governmental agencies filed a request for clarification or rehearing focusing on the remedy.

In November 2015, FERC issued an order denying MPS Merchant's request for rehearing and expanded the remedy to include additional MPS Merchant sales in the California markets. MPS Merchant filed another request for rehearing, challenging the expanded remedy.

In February 2016, FERC issued an order expanding the amount of revenues that MPS Merchant would be required to disgorge to include all revenues in excess of the FERC-determined competitive market clearing price for all sales in the California markets during the Summer Period that occurred in any hour in which any remaining respondent in the proceeding was found to have committed a tariff violation.

In October 2016, MPS Merchant reached a settlement agreement with certain California utilities and governmental agencies that would settle all issues in the case in exchange for $7.5 million of cash consideration as well as MPS Merchant's interest in additional funds it was entitled to during the refund period discussed above. The settlement agreement was filed with FERC in December 2016. In accordance with the terms of the settlement agreement, the $7.5 million of cash consideration will begin accruing interest at the FERC interest rate beginning on January 1, 2017, until the date paid.

In January 2017, FERC issued an order denying a motion filed in conjunction with and as a condition of the settlement agreement and ordered MPS Merchant and the California utilities and governmental agencies to notify FERC by February 27, 2017 whether they intended to revise the settlement agreement or withdraw it. In February 2017, MPS Merchant and the California utilities and governmental agencies filed a notice with FERC revising the settlement agreement to waive the condition of the settlement agreement that was contingent upon the motion denied by FERC. The revised settlement agreement is subject to approval by the Public Utilities Commission of the State of California and FERC.

As a result of the developments noted above, Great Plains Energy recorded a $7.5 million loss in other operating expenses in 2016.

17. GUARANTEES

In the ordinary course of business, Great Plains Energy and certain of its subsidiaries enter into various agreements providing financial or performance assurance to third parties on behalf of certain subsidiaries. Such agreements include, for example, guarantees and letters of credit. These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to a subsidiary on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiary's intended business purposes. The majority of these agreements guarantee the Company's own future performance, so a liability for the fair value of the obligation is not recorded.

At December 31, 2016, Great Plains Energy has provided $135.3 million of credit support for GMO as follows:

- Great Plains Energy direct guarantees to GMO counterparties totaling $38.7 million, which expire in 2017 and 2018 and
- Great Plains Energy guarantee of GMO long-term debt totaling $96.6 million, which includes debt with maturity dates ranging from 2017 to 2023.

Great Plains Energy has also guaranteed GMO's commercial paper program. At December 31, 2016, GMO had $201.9 million commercial paper outstanding.

18. RELATED PARTY TRANSACTIONS AND RELATIONSHIPS

KCP&L employees manage GMO's business and operate its facilities at cost, including GMO's 18% ownership interest in KCP&L's Iatan Nos. 1 and 2. The operating expenses and capital costs billed from KCP&L to GMO were $194.4 million for 2016, $183.6 million for 2015 and $173.9 million for 2014. Additionally, KCP&L and GMO engage in wholesale electricity transactions with each other. KCP&L's net wholesale sales to GMO were $0.8 million, $0.2 million and $12.7 million in 2016, 2015 and 2014, respectively.

KCP&L and GMO are also authorized to participate in the Great Plains Energy money pool, an internal financing arrangement in which funds may be lent on a short-term basis to KCP&L and GMO from Great Plains Energy and between KCP&L and GMO. At December 31, 2016 and 2015, KCP&L had no outstanding receivables or payables under the money pool.

The following table summarizes KCP&L's related party net receivables.

	December 31	
	2016	2015
	(millions)	
Net receivable from GMO	$ 64.6	$ 50.0
Net receivable from Great Plains Energy	2.6	15.8

19. DERIVATIVE INSTRUMENTS

Great Plains Energy and KCP&L are exposed to a variety of market risks including interest rates and commodity prices. Management has established risk management policies and strategies to reduce the potentially adverse effects that the volatility of the markets may have on Great Plains Energy's and KCP&L's operating results. Great Plains Energy's and KCP&L's interest rate risk management activities have included using derivative instruments to hedge against future interest rate fluctuations on anticipated debt issuances. Commodity risk management activities, including the use of certain derivative instruments, are subject to the management, direction and control of an internal commodity risk committee. Management maintains commodity price risk management strategies that use derivative instruments to reduce the effects of fluctuations in wholesale sales and fuel and purchased power expense caused by commodity price volatility.

Counterparties to commodity derivatives expose Great Plains Energy and KCP&L to credit loss in the event of nonperformance. This credit loss is limited to the cost of replacing these contracts at current market rates. Derivative instruments, excluding those instruments that qualify for the NPNS election, which are accounted for by accrual accounting, are recorded on the balance sheet at fair value as an asset or liability. Changes in the fair value of derivative instruments are recognized in net income, except hedges for KCP&L's and GMO's utility operations that are recorded to a regulatory asset or liability consistent with KCC and MPSC regulatory orders. For derivative contracts with counterparties under master netting arrangements, Great Plains Energy and KCP&L can net receivables and payables with each respective counterparty.

Interest Rate Risk Management

In June 2016, Great Plains Energy entered into four interest rate swaps, with a total notional amount of $4.4 billion, to hedge against interest rate fluctuations on future issuances of long-term debt expected to be issued to finance a portion of the cash consideration for the anticipated acquisition of Westar. Settlement of the interest rate swaps is contingent on the consummation of the anticipated acquisition of Westar. The interest rate swaps have been designated as economic hedges (non-hedging derivatives). The fair values of these instruments are recorded as derivative assets or liabilities with an offsetting entry recorded to interest charges.

Commodity Risk Management

KCP&L and GMO have Transmission Congestion Rights (TCRs) that they utilize to hedge against congestion costs and protect load prices in the Southwest Power Pool, Inc. (SPP) Integrated Marketplace. These financial contracts have been designated as economic hedges (non-hedging derivatives). The fair values of these instruments are recorded as derivative assets or liabilities with an offsetting entry recorded to a regulatory asset or liability. The settlement costs are included in a recovery mechanism. A regulatory asset or liability is recorded to reflect the change in the timing of recognition authorized by KCC and MPSC. Recovery of actual costs will not impact earnings, but will impact cash flows due to the timing of the recovery mechanism.

MPS Merchant, which has certain long-term natural gas contracts remaining from its former non-regulated trading operations, manages the daily delivery of its remaining contractual commitments with economic hedges (non-hedging derivatives) to reduce its exposure to changes in market prices. Within the trading portfolio, MPS Merchant takes certain positions to hedge physical sale or purchase contracts. MPS Merchant records the fair value of physical trading energy contracts as derivative assets or liabilities with an offsetting entry to the consolidated statements of comprehensive income.

The gross notional contract amount and recorded fair values of open positions for derivative instruments are summarized in the following table. The fair values of these derivatives are recorded on the consolidated balance sheets. The fair values below are gross values before netting agreements and netting of cash collateral.

	December 31			
	2016		2015	
	Notional Contract Amount	Fair Value	Notional Contract Amount	Fair Value
Great Plains Energy	(millions)			
Non-hedging derivatives				
Futures contracts	$ —	$ —	$ 26.6	$ (5.7)
Forward contracts	9.8	2.4	15.6	3.1
Transmission congestion rights	3.7	1.3	5.6	(0.5)
Interest rate swaps	4,415.0	79.3	—	—
KCP&L				
Non-hedging derivatives				
Futures contracts	$ —	$ —	$ 0.9	$ (0.1)
Transmission congestion rights	2.7	0.9	4.1	(0.4)

The fair values of Great Plains Energy's and KCP&L's open derivative positions and balance sheet classification are summarized in the following tables. The fair values below are gross values before netting agreements and netting of cash collateral.

Great Plains Energy

December 31, 2016	Balance Sheet Classification	Asset Derivatives Fair Value	Liability Derivatives Fair Value
Derivatives Not Designated as Hedging Instruments		(millions)	
Commodity contracts	Derivative instruments/Other	$ 4.3	$ 0.6
Interest rate contracts	Derivative instruments	79.3	—
December 31, 2015			
Derivatives Not Designated as Hedging Instruments			
Commodity contracts	Other/Derivative instruments	$ 3.3	$ 6.4

KCP&L

December 31, 2016	Balance Sheet Classification	Asset Derivatives Fair Value	Liability Derivatives Fair Value
Derivatives Not Designated as Hedging Instruments		(millions)	
Commodity contracts	Other	$ 1.3	$ 0.4
December 31, 2015			
Derivatives Not Designated as Hedging Instruments			
Commodity contracts	Other	$ 0.2	$ 0.7

The following tables provide information regarding Great Plains Energy's and KCP&L's offsetting of derivative assets and liabilities.

Great Plains Energy

Description	Gross Amounts Recognized	Gross Amounts Offset in the Statement of Financial Position	Net Amounts Presented in the Statement of Financial Position	Gross Amounts Not Offset in the Statement of Financial Position: Financial Instruments	Gross Amounts Not Offset in the Statement of Financial Position: Cash Collateral	Net Amount
December 31, 2016			(millions)			
Derivative assets	$ 83.6	$ (0.5)	$ 83.1	$ —	$ —	$ 83.1
Derivative liabilities	0.6	(0.5)	0.1	—	—	0.1
December 31, 2015						
Derivative assets	$ 3.3	$ (0.2)	$ 3.1	$ —	$ —	$ 3.1
Derivative liabilities	6.4	(5.9)	0.5	—	—	0.5

KCP&L

Description	Gross Amounts Recognized	Gross Amounts Offset in the Statement of Financial Position	Net Amounts Presented in the Statement of Financial Position	Gross Amounts Not Offset in the Statement of Financial Position: Financial Instruments	Gross Amounts Not Offset in the Statement of Financial Position: Cash Collateral	Net Amount
December 31, 2016			(millions)			
Derivative assets	$ 1.3	$ (0.4)	$ 0.9	$ —	$ —	$ 0.9
Derivative liabilities	0.4	(0.4)	—	—	—	—
December 31, 2015						
Derivative assets	$ 0.2	$ (0.2)	$ —	$ —	$ —	$ —
Derivative liabilities	0.7	(0.3)	0.4	—	—	0.4

At December 31, 2015, Great Plains Energy had offset $5.7 million of cash collateral posted with counterparties against net derivative positions.

See Note 21 for information regarding amounts reclassified out of accumulated other comprehensive loss for Great Plains Energy and KCP&L.

Great Plains Energy's accumulated OCI at December 31, 2016, includes $7.8 million that is expected to be reclassified to expenses over the next twelve months. KCP&L's accumulated OCI at December 31, 2016, includes $7.5 million that is expected to be reclassified to expenses over the next twelve months.

The following tables summarize the amounts of gain (loss) recognized for the change in fair value of derivatives not designated as hedging instruments for Great Plains Energy and KCP&L.

Great Plains Energy

Derivatives Not Designated as Hedging Instruments	2016	2015	2014
Location of Gain (Loss)		(millions)	
Electric revenues	$ 3.5	$ (8.2)	$ (14.2)
Fuel and purchased power	(2.7)	(4.0)	(3.4)
Interest charges	79.3	—	—
Regulatory asset	—	(6.8)	(2.7)
Regulatory liability	1.3	—	—
Total	$ 81.4	$ (19.0)	$ (20.3)

KCP&L

Derivatives Not Designated as Hedging Instruments	2016	2015	2014
Location of Gain (Loss)		(millions)	
Electric revenues	$ 3.5	$ (8.2)	$ (14.2)
Fuel and purchased power	0.1	1.5	1.1
Regulatory asset	—	(0.5)	(0.2)
Regulatory liability	1.0	—	—
Total	$ 4.6	$ (7.2)	$ (13.3)

20. FAIR VALUE MEASUREMENTS

GAAP defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. GAAP establishes a fair value hierarchy, which prioritizes the inputs to valuation techniques used to measure fair value into three broad categories, giving the highest priority to quoted prices in active markets for identical assets or liabilities and lowest priority to unobservable inputs. A definition of the various levels, as well as discussion of the various measurements within the levels, is as follows:

Level 1 – Unadjusted quoted prices for identical assets or liabilities in active markets that Great Plains Energy and KCP&L have access to at the measurement date.

Level 2 – Market-based inputs for assets or liabilities that are observable (either directly or indirectly) or inputs that are not observable but are corroborated by market data.

Level 3 – Unobservable inputs, reflecting Great Plains Energy's and KCP&L's own assumptions about the assumptions market participants would use in pricing the asset or liability.

Great Plains Energy and KCP&L record cash and cash equivalents and short-term borrowings on the balance sheet at cost, which approximates fair value due to the short-term nature of these instruments.

Great Plains Energy and KCP&L record long-term debt on the balance sheet at amortized cost. The fair value of long-term debt is measured as a Level 2 liability and is based on quoted market prices, with the incremental borrowing rate for similar debt used to determine fair value if quoted market prices are not available. At

December 31, 2016, the book value and fair value of Great Plains Energy's long-term debt, including current maturities, were $3.8 billion and $4.0 billion, respectively. At December 31, 2015, the book value and fair value of Great Plains Energy's long-term debt, including current maturities, were $3.7 billion and $4.0 billion, respectively. At December 31, 2016, the book value and fair value of KCP&L's long-term debt, including current maturities, were $2.6 billion and $2.7 billion, respectively. At December 31, 2015, the book value and fair value of KCP&L's long-term debt, including current maturities, were $2.6 billion and $2.8 billion, respectively.

The following tables include Great Plains Energy's and KCP&L's balances of financial assets and liabilities measured at fair value on a recurring basis. The fair values below are gross values before netting arrangements and netting of cash collateral.

Description	December 31 2016	Level 1	Level 2	Level 3
KCP&L		(millions)		
Assets				
Nuclear decommissioning trust [(a)]				
Equity securities	$ 153.9	$ 153.9	$ —	$ —
Debt securities				
U.S. Treasury	27.8	27.8	—	—
U.S. Agency	1.7	—	1.7	—
State and local obligations	3.2	—	3.2	—
Corporate bonds	32.4	—	32.4	—
Foreign governments	0.1	—	0.1	—
Cash equivalents	3.8	3.8	—	—
Total nuclear decommissioning trust	222.9	185.5	37.4	—
Self-insured health plan trust [(b)]				
Equity securities	0.9	0.9	—	—
Debt securities	4.8	0.1	4.7	—
Cash and cash equivalents	5.6	5.6	—	—
Total self-insured health plan trust	11.3	6.6	4.7	—
Derivative instruments - commodity [(c)]	1.3	—	—	1.3
Total	$ 235.5	$ 192.1	$ 42.1	$ 1.3
Liabilities				
Derivative instruments - commodity [(c)]	0.4	—	—	0.4
Total	$ 0.4	$ —	$ —	$ 0.4
Other Great Plains Energy				
Assets				
Derivative instruments				
Commodity [(c)]	$ 3.0	$ —	$ 2.2	$ 0.8
Interest rate [(d)]	79.3	—	—	79.3
Total	$ 82.3	$ —	$ 2.2	$ 80.1
Liabilities				
Derivative instruments - commodity [(c)]	0.2	—	0.1	0.1
Total	$ 0.2	$ —	$ 0.1	$ 0.1
Great Plains Energy				
Assets				
Nuclear decommissioning trust [(a)]	$ 222.9	$ 185.5	$ 37.4	$ —
Self-insured health plan trust [(b)]	11.3	6.6	4.7	—
Derivative instruments [(c)(d)]	83.6	—	2.2	81.4
Total	$ 317.8	$ 192.1	$ 44.3	$ 81.4
Liabilities				
Derivative instruments [(c)]	0.6	—	0.1	0.5
Total	$ 0.6	$ —	$ 0.1	$ 0.5

Description	December 31 2015	Level 1	Level 2	Level 3
KCP&L		(millions)		
Assets				
Nuclear decommissioning trust [a]				
Equity securities	$ 135.4	$ 135.4	$ —	$ —
Debt securities				
U.S. Treasury	26.4	26.4	—	—
U.S. Agency	1.8	—	1.8	—
State and local obligations	4.0	—	4.0	—
Corporate bonds	29.2	—	29.2	—
Foreign governments	0.3	—	0.3	—
Cash equivalents	3.6	3.6	—	—
Total nuclear decommissioning trust	200.7	165.4	35.3	—
Self-insured health plan trust [b]				
Equity securities	1.1	1.1	—	—
Debt securities	7.3	—	7.3	—
Cash and cash equivalents	5.2	5.2	—	—
Total self-insured health plan trust	13.6	6.3	7.3	—
Derivative instruments - commodity [c]	0.2	—	—	0.2
Total	$ 214.5	$ 171.7	$ 42.6	$ 0.2
Liabilities				
Derivative instruments - commodity [c]	0.7	0.1	—	0.6
Total	$ 0.7	$ 0.1	$ —	$ 0.6
Other Great Plains Energy				
Assets				
Derivative instruments - commodity [c]	$ 3.1	$ —	$ 2.7	$ 0.4
SERP rabbi trusts [e]				
Equity securities	0.1	0.1	—	—
Total	$ 3.2	$ 0.1	$ 2.7	$ 0.4
Liabilities				
Derivative instruments - commodity[c]	5.7	5.6	—	0.1
Total	$ 5.7	$ 5.6	$ —	$ 0.1
Great Plains Energy				
Assets				
Nuclear decommissioning trust [a]	$ 200.7	$ 165.4	$ 35.3	$ —
Self-insured health plan trust [b]	13.6	6.3	7.3	—
Derivative instruments [c]	3.3	—	2.7	0.6
SERP rabbi trusts [e]	0.1	0.1	—	—
Total	$ 217.7	$ 171.8	$ 45.3	$ 0.6
Liabilities				
Derivative instruments [c]	6.4	5.7	—	0.7
Total	$ 6.4	$ 5.7	$ —	$ 0.7

(a) Fair value is based on quoted market prices of the investments held by the fund and/or valuation models.

(b) Fair value is based on quoted market prices of the investments held by the trust. Debt securities classified as Level 1 are comprised of U.S. Treasury securities. Debt securities classified as Level 2 are comprised of corporate bonds, U.S. Agency, state and local obligations, and other asset-backed securities.

(c) The fair value of commodity derivative instruments is estimated using market quotes, over-the-counter forward price and volatility curves and correlations among fuel prices, net of estimated credit risk. Derivative instruments classified as Level 1 represent exchange traded derivative instruments. Derivative instruments classified as Level 2 represent non-exchange traded derivative instruments valued using pricing models for which observable market data is available to corroborate the valuation inputs. Derivative instruments classified as Level 3 represent non-exchange traded derivative instruments valued using pricing models for which observable market data is not available to corroborate the valuation inputs and TCRs valued at the most recent auction price in the SPP Integrated Marketplace.

(d) The fair value of interest rate derivative instruments is determined by calculating the net present value of expected payments and receipts under the interest rate swaps using observable market inputs including interest rates and LIBOR swap rates. As of December 31, 2016, the calculated net present value was discounted by a contingency factor of 0.35 that management believes is representative of what a market participant would use in valuing these instruments in order to account for the contingent nature of the settlement of these instruments. See Note 19 for more details on the interest rate swaps.

A decrease in the contingency factor would result in a higher fair value measurement. Management expects that the contingency factor will decrease as the Company obtains certain regulatory approvals connected with the anticipated acquisition of Westar and due to the passage of time. Because of the unobservable nature of the contingency factor, the interest rate derivatives have been classified as Level 3.

(e) At December 31, 2016 and 2015, the Supplemental Executive Retirement Plan (SERP) rabbi trusts also included $16.0 million and $16.6 million, respectively, of fixed income funds valued at NAV per share (or its equivalent) that are not categorized in the fair value hierarchy. The fixed income fund invests primarily in intermediate and long-term debt securities, can be redeemed immediately and is not subject to any restrictions on redemptions.

The following tables reconcile the beginning and ending balances for all Level 3 assets and liabilities measured at fair value on a recurring basis.

Great Plains Energy

Fair Value Measurements Using Significant Unobservable Inputs (Level 3)

	Derivative Instruments	
	2016	**2015**
	(millions)	
Net asset (liability) at January 1	$ (0.1)	$ 3.5
Total realized/unrealized gains (losses):		
included in electric revenue	3.5	(8.2)
included in fuel and purchased power expense	0.8	(1.5)
included in non-operating income	11.3	8.6
included in interest charges	79.3	—
included in regulatory (asset) liability	1.3	(0.5)
Purchases	0.3	—
Settlements	(15.5)	(2.0)
Net asset (liability) at December 31	$ 80.9	$ (0.1)
Total unrealized gains (losses) relating to assets and liabilities still on the consolidated balance sheet at December 31:		
included in non-operating income	$ 0.1	$ (0.2)
included in interest charges	79.3	—
included in regulatory (asset) liability	1.3	(0.5)

KCP&L

Fair Value Measurements Using Significant Unobservable Inputs (Level 3)

	Derivative Instruments	
	2016	**2015**
	(millions)	
Net asset (liability) at January 1	$ (0.4)	$ 3.1
Total realized/unrealized gains (losses):		
included in electric revenue	3.5	(8.2)
included in regulatory (asset) liability	1.0	(0.4)
Purchases	(0.3)	(0.8)
Settlements	(2.9)	5.9
Net asset (liability) at December 31	$ 0.9	$ (0.4)
Total unrealized gains (losses) relating to assets and liabilities still on the consolidated balance sheet at December 31:		
included in regulatory (asset) liability	$ 1.0	$ (0.4)

21. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

The following tables reflect the change in the balances of each component of accumulated other comprehensive loss for Great Plains Energy and KCP&L.

Great Plains Energy

	Gains and Losses on Cash Flow Hedges[(a)]	Defined Benefit Pension Items[(a)]	Total[(a)]
		(millions)	
2016			
Beginning balance January 1	$ (10.1)	$ (1.9)	$ (12.0)
Other comprehensive income (loss) before reclassifications	—	(0.7)	(0.7)
Amounts reclassified from accumulated other comprehensive loss	5.6	0.5	6.1
Net current period other comprehensive income	5.6	(0.2)	5.4
Ending balance December 31	$ (4.5)	$ (2.1)	$ (6.6)
2015			
Beginning balance January 1	$ (15.8)	$ (2.9)	$ (18.7)
Other comprehensive income before reclassifications	—	0.6	0.6
Amounts reclassified from accumulated other comprehensive loss	5.7	0.4	6.1
Net current period other comprehensive income	5.7	1.0	6.7
Ending balance December 31	$ (10.1)	$ (1.9)	$ (12.0)

(a) Net of tax

KCP&L

	Gains and Losses on Cash Flow Hedges[(a)]
	(millions)
2016	
Beginning balance January 1	$ (9.6)
Amounts reclassified from accumulated other comprehensive loss	5.4
Net current period other comprehensive income	5.4
Ending balance December 31	$ (4.2)
2015	
Beginning balance January 1	$ (14.9)
Amounts reclassified from accumulated other comprehensive loss	5.3
Net current period other comprehensive income	5.3
Ending balance December 31	$ (9.6)

(a) Net of tax

The following tables reflect the effect on certain line items of net income from amounts reclassified out of each component of accumulated other comprehensive loss for Great Plains Energy and KCP&L.

Great Plains Energy

Details about Accumulated Other Comprehensive Loss Components	Amount Reclassified from Accumulated Other Comprehensive Loss		Affected Line Item in the Income Statement
	2016	2015	
	(millions)		
Gains and (losses) on cash flow hedges (effective portion)			
Interest rate contracts	$ (9.2)	$ (9.2)	Interest charges
	(9.2)	(9.2)	Income before income tax expense and income from equity investments
	3.6	3.5	Income tax benefit
	$ (5.6)	$ (5.7)	Net income
Amortization of defined benefit pension items			
Net losses included in net periodic benefit costs	$ (0.8)	$ (0.7)	Utility operating and maintenance expenses
	(0.8)	(0.7)	Income before income tax expense and income from equity investments
	0.3	0.3	Income tax benefit
	$ (0.5)	$ (0.4)	Net income
Total reclassifications, net of tax	$ (6.1)	$ (6.1)	Net income

KCP&L

Details about Accumulated Other Comprehensive Loss Components	Amount Reclassified from Accumulated Other Comprehensive Loss		Affected Line Item in the Income Statement
	2016	2015	
	(millions)		
Gains and (losses) on cash flow hedges (effective portion)			
Interest rate contracts	$ (8.8)	$ (8.7)	Interest charges
	(8.8)	(8.7)	Income before income tax expense
	3.4	3.4	Income tax benefit
Total reclassifications, net of tax	$ (5.4)	$ (5.3)	Net income

22. TAXES

Components of income tax expense are detailed in the following tables.

Great Plains Energy	**2016**	**2015**	**2014**
Current income taxes		(millions)	
Federal	$ 0.3	$ (0.2)	$ 0.4
State	0.7	(1.1)	(0.1)
Total	1.0	(1.3)	0.3
Deferred income taxes			
Federal	140.6	96.9	104.2
State	29.5	28.0	21.6
Total	170.1	124.9	125.8
Noncurrent income taxes			
Federal	—	—	(2.4)
State	—	—	(0.5)
Foreign	—	—	(6.1)
Total	—	—	(9.0)
Investment tax credit			
Deferral	2.5	0.5	—
Amortization	(1.4)	(1.4)	(1.4)
Total	1.1	(0.9)	(1.4)
Income tax expense	$ 172.2	$ 122.7	$ 115.7

KCP&L	**2016**	**2015**	**2014**
Current income taxes		(millions)	
Federal	$ 24.8	$ (18.7)	$ (9.4)
State	4.7	(3.4)	(2.3)
Total	29.5	(22.1)	(11.7)
Deferred income taxes			
Federal	76.4	81.9	72.6
State	17.0	17.5	15.8
Total	93.4	99.4	88.4
Investment tax credit			
Deferral	—	0.5	—
Amortization	(1.0)	(1.0)	(1.0)
Total	(1.0)	(0.5)	(1.0)
Income tax expense	$ 121.9	$ 76.8	$ 75.7

Effective Income Tax Rates

Effective income tax rates reflected in the financial statements and the reasons for their differences from the statutory federal rates are detailed in the following tables.

Great Plains Energy	**2016**	**2015**	**2014**
Federal statutory income tax rate	35.0%	35.0%	35.0%
Differences between book and tax depreciation not normalized	(0.1)	—	(0.7)
Amortization of investment tax credits	(0.3)	(0.4)	(0.4)
Federal income tax credits	(2.6)	(4.1)	(3.8)
State income taxes	4.2	4.0	3.8
Changes in uncertain tax positions, net	—	—	(1.7)
Transaction costs	0.9	—	—
Valuation allowance	—	1.5	—
Other	0.2	0.5	0.1
Effective income tax rate	37.3%	36.5%	32.3%

KCP&L	**2016**	**2015**	**2014**
Federal statutory income tax rate	35.0%	35.0%	35.0%
Differences between book and tax depreciation not normalized	(0.3)	—	(0.9)
Amortization of investment tax credits	(0.3)	(0.5)	(0.4)
Federal income tax credits	(3.1)	(5.6)	(5.6)
State income taxes	4.1	4.0	3.7
Valuation allowance	—	0.3	—
Other	(0.2)	0.3	—
Effective income tax rate	35.2%	33.5%	31.8%

Deferred Income Taxes

The tax effects of major temporary differences resulting in deferred income tax assets (liabilities) in the consolidated balance sheets are in the following tables.

	Great Plains Energy		KCP&L	
December 31	**2016**	**2015**	**2016**	**2015**
Noncurrent deferred income taxes				
Plant related	(2,107.6)	(1,967.0)	(1,492.2)	(1,398.9)
Income taxes on future regulatory recoveries	(148.7)	(151.3)	(123.9)	(125.0)
Derivative instruments	(17.0)	20.5	8.5	14.0
Pension and post-retirement benefits	10.5	(0.1)	38.6	27.4
SO_2 emission allowance sales	24.1	25.7	24.1	25.7
Fuel recovery mechanisms	(22.3)	(4.5)	(27.2)	(6.3)
Tax credit carryforwards	271.1	256.8	177.4	166.6
Customer demand programs	(34.3)	(22.7)	(21.8)	(16.9)
Solar rebates	(27.3)	(31.9)	(11.4)	(13.1)
Net operating loss carryforward	718.0	734.9	198.3	204.2
Other	20.2	0.7	1.3	(9.6)
Net noncurrent deferred income tax liability before valuation allowance	(1,313.3)	(1,138.9)	(1,228.3)	(1,131.9)
Valuation allowance	(16.4)	(19.9)	—	(0.7)
Net noncurrent deferred income tax liability	(1,329.7)	(1,158.8)	(1,228.3)	(1,132.6)

	Great Plains Energy		KCP&L	
December 31	**2016**	**2015**	**2016**	**2015**
		(millions)		
Gross deferred income tax assets	$ 1,360.9	$ 1,368.5	$ 747.7	$ 740.9
Gross deferred income tax liabilities	(2,690.6)	(2,527.3)	(1,976.0)	(1,873.5)
Net deferred income tax liability	$(1,329.7)	$(1,158.8)	$(1,228.3)	$(1,132.6)

Tax Credit Carryforwards

At December 31, 2016 and 2015, Great Plains Energy had $183.5 million and $169.2 million, respectively, of federal general business income tax credit carryforwards. At December 31, 2016 and 2015, KCP&L had $177.4 million and $166.6 million, respectively, of federal general business income tax credit carryforwards. The carryforwards for both Great Plains Energy and KCP&L relate primarily to Advanced Coal Investment Tax Credits and Wind Production tax credits and expire in the years 2028 to 2036. Approximately $0.5 million of Great Plains Energy's credits are related to Low Income Housing credits that were acquired in the GMO acquisition. Due to federal limitations on the utilization of income tax attributes acquired in the GMO acquisition, management expects a portion of these credits to expire unutilized and has provided a valuation allowance against $0.4 million of the federal income tax benefit.

At December 31, 2016 and 2015, Great Plains Energy had $87.6 million of federal alternative minimum tax credit carryforwards, all of which was acquired in the GMO acquisition. These credits do not expire and can be used to reduce taxes paid in the future.

Net Operating Loss Carryforwards

At December 31, 2016 and 2015, Great Plains Energy had $643.8 million and $656.1 million, respectively, of tax benefits related to federal net operating loss (NOL) carryforwards. Approximately $306.2 million at December 31, 2016 and $313.2 million at December 31, 2015, respectively, are tax benefits related to NOLs that were acquired in the GMO acquisition. The tax benefits for NOLs originating in 2003 are $23.0 million, $152.4 million originating in 2004, $74.1 million originating in 2005, $53.3 million originating in 2006, $1.3 million originating in 2007, $2.4 million originating in 2008, $36.5 million originating in 2009, $4.1 million originating in 2010, $108.8 million originating in 2011, $2.1 million originating in 2012, $1.4 million originating in 2013, $86.3 million originating in 2014 and $98.1 million originating in 2015. The federal NOL carryforwards expire in years 2023 to 2036.

In addition, Great Plains Energy also had deferred tax benefits of $74.2 million and $78.8 million related to state NOLs as of December 31, 2016 and 2015, respectively. Of these amounts, approximately $36.1 million and $39.2 million at December 31, 2016 and 2015, respectively, were acquired in the GMO acquisition. Management does not expect to utilize $16.0 million of NOLs in state tax jurisdictions where the Company does not expect to operate in the future. Therefore, a valuation allowance has been provided against $16.0 million of state tax benefits.

Valuation Allowances

Great Plains Energy is required to assess the ultimate realization of deferred tax assets using a "more likely than not" assessment threshold. This assessment takes into consideration tax planning strategies within Great Plains Energy's control. As a result of this assessment, Great Plains Energy has established a partial valuation allowance for federal and state tax NOL carryforwards and tax credit carryforwards. During 2016, $3.5 million of tax expense was recorded in continuing operations primarily related to state NOL carryforwards that expired at December 31, 2016.

23. SEGMENTS AND RELATED INFORMATION

Great Plains Energy has one reportable segment based on its method of internal reporting, which segregates reportable segments based on products and services, management responsibility and regulation. The one reportable business segment is electric utility, consisting of KCP&L, GMO's regulated utility operations and GMO Receivables Company. Other includes GMO activity other than its regulated utility operations, GPETHC and unallocated corporate charges, including certain costs to achieve the anticipated acquisition of Westar. The summary of significant accounting policies applies to the reportable segment. Segment performance is evaluated based on net income.

The following tables reflect summarized financial information concerning Great Plains Energy's reportable segment.

2016	Electric Utility	Other	Eliminations	Great Plains Energy
		(millions)		
Operating revenues	$ 2,676.0	$ —	$ —	$ 2,676.0
Depreciation and amortization	(344.8)	—	—	(344.8)
Interest charges	(196.1)	2.5	32.1	(161.5)
Income tax expense	(164.3)	(7.9)	—	(172.2)
Net income (loss)	292.1	(2.1)	—	290.0

2015	Electric Utility	Other	Eliminations	Great Plains Energy
		(millions)		
Operating revenues	$ 2,502.2	$ —	$ —	$ 2,502.2
Depreciation and amortization	(330.4)	—	—	(330.4)
Interest charges	(190.9)	(40.5)	32.1	(199.3)
Income tax expense	(120.8)	(1.9)	—	(122.7)
Net income (loss)	223.8	(10.8)	—	213.0

2014	Electric Utility	Other	Eliminations	Great Plains Energy
		(millions)		
Operating revenues	$ 2,568.2	$ —	$ —	$ 2,568.2
Depreciation and amortization	(306.0)	—	—	(306.0)
Interest charges	(183.0)	(41.2)	35.7	(188.5)
Income tax (expense) benefit	(125.6)	9.9	—	(115.7)
Net income (loss)	243.5	(0.7)	—	242.8

	Electric Utility	Other	Eliminations	Great Plains Energy
2016		(millions)		
Assets	$11,444.2	$ 2,461.3	$ (335.5)	$13,570.0
Capital expenditures	609.4	—	—	609.4
2015				
Assets	$11,045.5	$ (51.1)	$ (255.8)	$10,738.6
Capital expenditures	677.1	—	—	677.1
2014				
Assets	$10,727.7	$ 29.2	$ (303.5)	$10,453.4
Capital expenditures	773.7	—	—	773.7

24. JOINTLY-OWNED ELECTRIC UTILITY PLANTS

Great Plains Energy's and KCP&L's share of jointly-owned electric utility plants at December 31, 2016, are detailed in the following tables.

Great Plains Energy

	Wolf Creek Unit	La Cygne Units	Iatan No. 1 Unit	Iatan No. 2 Unit	Iatan Common	Jeffrey Energy Center
			(millions, except MW amounts)			
Great Plains Energy's share	47%	50%	88%	73%	79%	8%
Utility plant in service	$ 1,853.1	$ 1,099.5	$ 670.2	$ 1,334.9	$ 490.6	$ 196.1
Accumulated depreciation	889.6	275.6	261.6	387.3	126.3	80.1
Nuclear fuel, net	62.0	—	—	—	—	—
Construction work in progress	83.5	30.6	19.9	41.7	22.1	3.7
2017 accredited capacity-MWs	549	699	616	641	NA	172

KCP&L

	Wolf Creek Unit	La Cygne Units	Iatan No. 1 Unit	Iatan No. 2 Unit	Iatan Common
			(millions, except MW amounts)		
KCP&L's share	47%	50%	70%	55%	61%
Utility plant in service	$ 1,853.1	$ 1,099.5	$ 532.8	$ 1,022.4	$ 403.1
Accumulated depreciation	889.6	275.6	210.8	346.6	113.0
Nuclear fuel, net	62.0	—	—	—	—
Construction work in progress	83.5	30.6	8.4	23.1	5.0
2017 accredited capacity-MWs	549	699	490	482	NA

Each owner must fund its own portion of the plant's operating expenses and capital expenditures. KCP&L's and GMO's share of direct expenses are included in the appropriate operating expense classifications in Great Plains Energy's and KCP&L's financial statements.

25. QUARTERLY OPERATING RESULTS (UNAUDITED)

	Quarter			
Great Plains Energy	**1st**	**2nd**	**3rd**	**4th**
2016	(millions, except per share amounts)			
Operating revenue	$ 572.1	$ 670.8	$ 856.8	$ 576.3
Operating income	89.9	182.3	281.9	64.8
Net income	26.4	32.0	133.6	98.0
Basic and diluted earnings per common share	0.17	0.20	0.86	0.39
2015				
Operating revenue	$ 549.1	$ 609.0	$ 781.4	$ 562.7
Operating income	70.1	119.9	256.7	83.4
Net income	18.9	44.4	126.8	22.9
Basic and diluted earnings per common share	0.12	0.28	0.82	0.15

	Quarter			
KCP&L	**1st**	**2nd**	**3rd**	**4th**
2016	(millions)			
Operating revenue	$ 400.9	$ 475.6	$ 597.6	$ 401.3
Operating income	70.6	137.9	219.2	54.4
Net income	24.6	65.9	117.7	16.8
2015				
Operating revenue	$ 370.4	$ 417.4	$ 526.3	$ 399.7
Operating income	45.3	79.3	170.8	68.6
Net income	13.2	29.4	84.3	25.9

Quarterly data is subject to seasonal fluctuations with peak periods occurring in the summer months.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

GREAT PLAINS ENERGY

Disclosure Controls and Procedures

Great Plains Energy carried out an evaluation of its disclosure controls and procedures (as defined in Rules 13a-15 (e) or 15d-15(e) under the Securities Exchange Act of 1934, as amended (the Exchange Act)). This evaluation was conducted under the supervision, and with the participation, of Great Plains Energy's management, including the chief executive officer and chief financial officer, and Great Plains Energy's disclosure committee. Based upon this evaluation, the chief executive officer and chief financial officer of Great Plains Energy have concluded as of the end of the period covered by this report that the disclosure controls and procedures of Great Plains Energy were effective at a reasonable assurance level.

Changes in Internal Control Over Financial Reporting

There has been no change in Great Plains Energy's internal control over financial reporting (as defined in Rule 13a-15(f) and 15d-15(f) of the Exchange Act) that occurred during the quarterly period ended December 31, 2016, that has materially affected, or is reasonably likely to materially affect, its internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of the effectiveness of internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) for Great Plains Energy. Under the supervision and with the participation of Great Plains Energy's chief executive officer and chief financial officer, management evaluated the effectiveness of Great Plains Energy's internal control over financial reporting as of December 31, 2016. Management used for this evaluation the framework in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations (COSO) of the Treadway Commission.

Management has concluded that, as of December 31, 2016, Great Plains Energy's internal control over financial reporting is effective based on the criteria set forth in the COSO framework. Deloitte & Touche LLP, the independent registered public accounting firm that audited the financial statements included in this annual report on Form 10-K, has issued its attestation report on Great Plains Energy's internal control over financial reporting, which is included below.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
Great Plains Energy Incorporated
Kansas City, Missouri

We have audited the internal control over financial reporting of Great Plains Energy Incorporated and subsidiaries (the "Company") as of December 31, 2016, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Report on Internal Control Over Financial Reporting.* Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on the criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedules as of and for the year ended December 31, 2016, of the Company and our report dated February 23, 2017, expressed an unqualified opinion on those financial statements and financial statement schedules.

/s/DELOITTE & TOUCHE LLP

Kansas City, Missouri
February 23, 2017

KCP&L

Disclosure Controls and Procedures

KCP&L carried out an evaluation of its disclosure controls and procedures (as defined in Rules 13a-15(e) or 15d-15 (e) under the Exchange Act). This evaluation was conducted under the supervision, and with the participation, of KCP&L's management, including the chief executive officer and chief financial officer, and KCP&L's disclosure committee. Based upon this evaluation, the chief executive officer and chief financial officer of KCP&L have concluded as of the end of the period covered by this report that the disclosure controls and procedures of KCP&L were effective at a reasonable assurance level.

Changes in Internal Control Over Financial Reporting

There has been no change in KCP&L's internal control over financial reporting (as defined in Rule 13a-15(f) and 15d-15(f) of the Exchange Act) that occurred during the quarterly period ended December 31, 2016, that has materially affected, or is reasonably likely to materially affect, its internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of the effectiveness of internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) for KCP&L. Under the supervision and with the participation of KCP&L's chief executive officer and chief financial officer, management evaluated the effectiveness of KCP&L's internal control over financial reporting as of December 31, 2016. Management used for this evaluation the framework in *Internal Control - Integrated Framework (2013)* issued by the COSO of the Treadway Commission.

Management has concluded that, as of December 31, 2016, KCP&L's internal control over financial reporting is effective based on the criteria set forth in the COSO framework. Deloitte & Touche LLP, the independent registered public accounting firm that audited the financial statements included in this annual report on Form 10-K, has issued its attestation report on KCP&L's internal control over financial reporting, which is included below.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Kansas City Power & Light Company
Kansas City, Missouri

We have audited the internal control over financial reporting of Kansas City Power & Light Company and subsidiaries (the "Company") as of December 31, 2016, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Report on Internal Control Over Financial Reporting*. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on the criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2016, of the Company and our report dated February 23, 2017, expressed an unqualified opinion on those financial statements and financial statement schedule.

/s/DELOITTE & TOUCHE LLP

Kansas City, Missouri
February 23, 2017

ITEM 9B. OTHER INFORMATION

On February 21, 2017, Scott H. Heidtbrink, Executive Vice President and Chief Operating Officer of KCP&L and GMO, informed the companies of his decision to retire from his position as Executive Vice President and Chief Operating Officer effective upon the closing of Great Plains Energy's anticipated acquisition of Westar.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Great Plains Energy Directors
The information required by this item is incorporated by reference from the Great Plains Energy 2017 Proxy Statement (Proxy Statement), which will be filed with the SEC no later than March 23, 2017:

- Information regarding the directors of Great Plains Energy required by this item is contained in the Proxy Statement section titled “Election of Directors.”
- Information regarding compliance with Section 16(a) of the Securities Exchange Act of 1934 required by this item is contained in the Proxy Statement section titled “Security Ownership of Certain Beneficial Owners, Directors and Officers - Section 16(a) Beneficial Ownership Reporting Compliance.”
- Information regarding the Audit Committee of Great Plains Energy required by this item is contained in the Proxy Statement section titled “Corporate Governance - Committees of the Board.”

Great Plains Energy and KCP&L Executive Officers
Information required by this item regarding the executive officers of Great Plains Energy and KCP&L is contained in this report in the Part I, Item 1 section titled “Executive Officers.”

Great Plains Energy and KCP&L Code of Ethical Business Conduct
The Companies have adopted a Code of Ethical Business Conduct (Code), which applies to all directors, officers and employees of Great Plains Energy, KCP&L and their subsidiaries. The Code is posted on the corporate governance page of the Internet websites at www.greatplainsenergy.com and www.kcpl.com. A copy of the Code is available, without charge, upon written request to Corporate Secretary, Great Plains Energy Incorporated, 1200 Main St., Kansas City, Missouri 64105. Great Plains Energy and KCP&L intend to satisfy the disclosure requirements under Item 5.05 of Form 8-K regarding an amendment to, or a waiver from, a provision of the Code that applies to the principal executive officer, principal financial officer, principal accounting officer or controller of those companies by posting such information on the corporate governance page of the Internet websites.

Other KCP&L Information
The other information required by this item regarding KCP&L has been omitted in reliance on General Instruction (I).

ITEM 11. EXECUTIVE COMPENSATION

Great Plains Energy
The information required by this item contained in the sections titled “Executive Compensation,” “Director Compensation,” “Compensation Discussion and Analysis”, “Compensation Committee Report” and “Director Independence - Compensation Committee Interlocks and Insider Participation” of the Proxy Statement is incorporated by reference.

KCP&L
The other information required by this item regarding KCP&L has been omitted in reliance on General Instruction (I).

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Great Plains Energy

The information required by this item regarding security ownership of the directors and executive officers of Great Plains Energy contained in the section titled "Security Ownership of Certain Beneficial Owners, Directors and Officers" of the Proxy Statement is incorporated by reference.

KCP&L

The information required by this item regarding KCP&L has been omitted in reliance on General Instruction (I).

Equity Compensation Plans

Great Plains Energy's Long-Term Incentive Plan is an equity compensation plan approved by its shareholders. The Long-Term Incentive Plan permits the grant of restricted stock, restricted stock units, bonus shares, stock options, stock appreciation rights, limited stock appreciation rights, director shares, director deferred share units and performance shares to directors, officers and other employees of Great Plains Energy and KCP&L.

KCP&L does not have an equity compensation plan; however, KCP&L officers and certain employees participate in Great Plains Energy's Long-Term Incentive Plan.

The following table provides information, as of December 31, 2016, regarding the number of common shares to be issued upon exercise of outstanding options, warrants and rights, their weighted average exercise price, and the number of shares of common stock remaining available for future issuance. The table excludes shares issued or issuable under Great Plains Energy's defined contribution savings plans.

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders			
Great Plains Energy Long-Term Incentive Plan	763,687 [1]	$ — [2]	4,239,813
Equity compensation plans not approved by security holders	—	—	—
Total	763,687 [1]	$ — [2]	4,239,813

[1] Includes 625,100 performance shares at target performance levels and director deferred share units for 138,587 shares of Great Plains Energy common stock outstanding at December 31, 2016.
[2] The performance shares and director deferred share units have no exercise price and therefore are not reflected in the weighted average exercise price.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Great Plains Energy

The information required by this item contained in the sections titled "Director Independence" and "Related Party Transactions" of the Proxy Statement is incorporated by reference.

KCP&L

The information required by this item regarding KCP&L has been omitted in reliance on General Instruction (I).

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Great Plains Energy

The information required by this item regarding the independent auditors of Great Plains Energy and its subsidiaries contained in the section titled “Ratification of Appointment of Independent Auditors” of the Proxy Statement is incorporated by reference.

KCP&L

The Audit Committee of the Great Plains Energy Board functions as the Audit Committee of KCP&L. The following table sets forth the aggregate fees billed by Deloitte & Touche LLP for audit services rendered in connection with the consolidated financial statements and reports for 2016 and 2015 and for other services rendered during 2016 and 2015 on behalf of KCP&L, as well as all out-of-pocket costs incurred in connection with these services:

Fee Category	2016	2015
Audit Fees	$ 1,184,550	$ 1,201,819
Audit-Related Fees	21,000	20,000
Tax Fees	24,822	5,751
All Other Fees	—	8,802
Total Fees	$ 1,230,372	$ 1,236,372

Audit Fees: Consists of fees billed for professional services rendered for the audits of the annual consolidated financial statements of KCP&L and reviews of the interim condensed consolidated financial statements included in quarterly reports. Audit fees also include: services provided by Deloitte & Touche LLP in connection with statutory and regulatory filings or engagements; audit reports on audits of the effectiveness of internal control over financial reporting and other attest services, except those not required by statute or regulation; services related to filings with the SEC, including comfort letters, consents and assistance with and review of documents filed with the SEC; and accounting research in support of the audit.

Audit-Related Fees: Consists of fees billed for assurance and related services that are reasonably related to the performance of the audit or review of consolidated financial statements of KCP&L and are not reported under “Audit Fees”. These services include consultation concerning financial accounting and reporting standards.

Tax Fees: Consists of fees billed for tax compliance and related support of tax returns and other tax services, including assistance with tax audits, and tax research and planning.

All Other Fees: Consists of fees for all other services other than those described above.

Audit Committee Pre-Approval of Audit and Permissible Non-Audit Services

The Audit Committee has adopted policies and procedures for the pre-approval of all audit services, audit-related services, tax services and other services to be provided by the independent registered public accounting firm for KCP&L. The Audit Committee's policy is to pre-approve all audit, audit-related, tax or other services to be provided by the independent registered public accounting firm. Under these policies and procedures, the Audit Committee may pre-approve certain types of services, up to the aggregate fee levels it sets. Any proposed service within a pre-approved type of service that would cause the applicable fee level to be exceeded cannot be provided unless the Audit Committee either amends the applicable fee level or specifically approves the proposed service. The Audit Committee, as well, may specifically approve audit, audit-related, tax or other services on a case-by-case basis. Pre-approval is generally provided for up to one year, unless the Audit Committee specifically provides for a different period. The Company provides quarterly updates to the Audit Committee regarding actual fees spent with respect to pre-approved services. The Chairman of the Audit Committee may pre-approve audit, audit-related, tax and other services provided by the independent registered public accounting firm as required between meetings and report such pre-approval at the next Audit Committee meeting.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

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Exhibits

Exhibit Number		Description of Document	Registrant
2.1	*	Agreement and Plan of Merger, dated as of May 29, 2016, by and among Westar Energy, Inc., Great Plains Energy Incorporated and, from and after its accession thereto, Merger Sub (as defined therein) (Exhibit 2.1 to Form 8-K filed on May 31, 2016).	Great Plains Energy
3.1	*	Articles of Incorporation of Great Plains Energy Incorporated, as amended effective September 26, 2016 (Exhibit 3.1 to Form 10-Q for the quarter ended September 30, 2016).	Great Plains Energy
3.2	*	Certificate of Designations of the 7.00% Series B Mandatory Convertible Preferred Stock of Great Plains Energy Incorporated, filed with the Secretary of State of the State of Missouri and effective September 30, 2016. (Exhibit 3.1 to Form 8-K filed on October 3, 2016).	Great Plains Energy
3.3	*	Amended and Restated By-laws of Great Plains Energy Incorporated, as amended December 10, 2013 (Exhibit 3.1 to Form 8-K filed on December 16, 2013).	Great Plains Energy
3.4	*	Amended and Restated Articles of Consolidation of Kansas City Power & Light Company, restated as of May 6, 2014 (Exhibit 3.2 to Form 10-Q for the quarter ended March 31, 2014).	KCP&L
3.5	*	Amended and Restated By-laws of Kansas City Power & Light Company, as amended December 10, 2013 (Exhibit 3.3 to Form 8-K filed on December 16, 2013).	KCP&L
4.1	*	Indenture, dated as of June 1, 2004, between Great Plains Energy Incorporated and BNY Midwest Trust Company, as trustee (Exhibit 4.4 to Form 8-A/A filed on June 14, 2004).	Great Plains Energy
4.2	*	First Supplemental Indenture, dated as of June 14, 2004, between Great Plains Energy Incorporated and BNY Midwest Trust Company, as trustee (Exhibit 4.5 to Form 8-A/A filed on June 14, 2004).	Great Plains Energy
4.3	*	Second Supplemental Indenture, dated as of September 25, 2007, between Great Plains Energy Incorporated and The Bank of New York Trust Company, N.A., as trustee (Exhibit 4.1 to Form 8-K filed on September 26, 2007).	Great Plains Energy
4.4	*	Third Supplemental Indenture, dated as of August 13, 2010, between Great Plains Energy Incorporated and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.1 to Form 8-K filed on August 13, 2010).	Great Plains Energy
4.5	*	Fourth Supplemental Indenture, dated as of May 19, 2011, between Great Plains Energy Incorporated and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.1 to Form 8-K filed on May 19, 2011).	Great Plains Energy
4.6	*	Subordinated Indenture, dated as of May 18, 2009, between Great Plains Energy Incorporated and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.1 to Form 8-K filed on May 19, 2009).	Great Plains Energy

4.7	*	Supplemental Indenture No. 1, dated as of May 18, 2009, between Great Plains Energy Incorporated and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.2 to Form 8-K filed on May 19, 2009).	Great Plains Energy
4.8	*	Supplemental Indenture No. 2, dated as of March 22, 2012, between Great Plains Energy Incorporated and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.1 to Form 8-K filed on March 23, 2012).	Great Plains Energy
4.9	*	Indenture, dated as of August 24, 2001, between Aquila, Inc. and BankOne Trust Company, N.A., as trustee (Exhibit 4(d) to Registration Statement on Form S-3 (File No. 333-68400) filed by Aquila, Inc. on August 27, 2001).	Great Plains Energy
4.10	*	Second Supplemental Indenture, dated as of July 3, 2002, between Aquila, Inc. and BankOne Trust Company, N.A., as trustee (Exhibit 4(c) to Form S-4 (File No. 333-100204) filed by Aquila, Inc. on September 30, 2002).	Great Plains Energy
4.11	*	General Mortgage and Deed of Trust, dated as of December 1, 1986, between Kansas City Power & Light Company and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee (Exhibit 4-bb to Form 10-K for the year ended December 31, 1986).	Great Plains Energy KCP&L
4.12	*	Fifth Supplemental Indenture, dated as of September 15, 1992, between Kansas City Power & Light Company and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee (Exhibit 4-a to Form 10-Q for the quarter ended September 30, 1992).	Great Plains Energy KCP&L
4.13	*	Eighth Supplemental Indenture, dated as of December 1, 1993, between Kansas City Power & Light Company and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee (Exhibit 4-o to Registration Statement, Registration No. 33-51799).	Great Plains Energy KCP&L
4.14	*	Eleventh Supplemental Indenture, dated as of August 15, 2005, between Kansas City Power & Light Company and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee (Exhibit 4.2 to Form 10-Q for the quarter ended September 30, 2005).	Great Plains Energy KCP&L
4.15	*	Twelfth Supplemental Indenture, dated as of March 1, 2009, between Kansas City Power & Light Company and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee (Exhibit 4.2 to Form 8-K filed on March 24, 2009).	Great Plains Energy KCP&L
4.16	*	Thirteenth Supplemental Indenture, dated as of March 1, 2009, between Kansas City Power & Light Company and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee (Exhibit 4.3 to Form 8-K filed on March 24, 2009).	Great Plains Energy KCP&L
4.17	*	Fourteenth Supplemental Indenture, dated as of March 1, 2009, between Kansas City Power & Light Company and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee (Exhibit 4.4 to Form 8-K filed on March 24, 2009).	Great Plains Energy KCP&L

4.18	*	Fifteenth Supplemental Indenture, dated as of June 30, 2011, between Kansas City Power & Light Company and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee (Exhibit 4.1 to Form 10-Q for the quarter ended June 30, 2011).	Great Plains Energy KCP&L
4.19	*	Indenture, dated as of December 1, 2000, between Kansas City Power & Light Company and The Bank of New York, as trustee (Exhibit 4(a) to Form 8-K filed on December 18, 2000).	Great Plains Energy KCP&L
4.20	*	Indenture, dated as of March 1, 2002, between Kansas City Power & Light Company and The Bank of New York, as trustee (Exhibit 4.1.b. to Form 10-Q for the quarter ended March 31, 2002).	Great Plains Energy KCP&L
4.21	*	Supplemental Indenture No. 1, dated as of November 15, 2005, between Kansas City Power & Light Company and The Bank of New York, as trustee (Exhibit 4.2.j to Form 10-K for the year ended December 31, 2005).	Great Plains Energy KCP&L
4.22	*	Indenture, dated as of May 1, 2007, between Kansas City Power & Light Company and The Bank of New York Trust Company, N.A., as trustee (Exhibit 4.1 to Form 8-K filed on June 4, 2007).	Great Plains Energy KCP&L
4.23	*	Supplemental Indenture No. 1, dated as of June 4, 2007, between Kansas City Power & Light Company and The Bank of New York Trust Company, N.A., as trustee (Exhibit 4.2 to Form 8-K filed on June 4, 2007).	Great Plains Energy KCP&L
4.24	*	Supplemental Indenture No. 2, dated as of March 11, 2008, between Kansas City Power & Light Company and The Bank of New York Trust Company, N.A., as trustee (Exhibit 4.2 to Form 8-K filed on March 11, 2008).	Great Plains Energy KCP&L
4.25	*	Supplemental Indenture No. 3, dated as of September 20, 2011, between Kansas City Power & Light Company and The Bank of New York Mellon Trust Company, N.A., Trustee (Exhibit 4.1 to Form 8-K filed on September 20, 2011).	Great Plains Energy KCP&L
4.26	*	Supplemental Indenture No. 4, dated as of March 14, 2013, between Kansas City Power & Light Company and The Bank of New York Mellon Trust Company, N.A., Trustee (Exhibit 4.1 to Form 8-K filed on March 14, 2013).	Great Plains Energy KCP&L
4.27	*	Supplemental Indenture No. 5, dated as of August 18, 2015, between Kansas City Power & Light Company and The Bank of New York Mellon Trust Company, N.A., Trustee (Exhibit 4.1 to Form 8-K filed on August 18, 2015).	Great Plains Energy KCP&L
4.28	*	Note Purchase Agreement, dated August 16, 2013, among KCP&L Greater Missouri Operations Company and the purchasers party thereto (Exhibit 4.1 to Form 8-K filed on August 19, 2013).	Great Plains Energy
10.1	*+	Great Plains Energy Incorporated Amended Long-Term Incentive Plan, effective on May 7, 2002 (Exhibit 10.1.a to Form 10-K for the year ended December 31, 2002).	Great Plains Energy KCP&L

10.2	*+	Great Plains Energy Incorporated Amended Long-Term Incentive Plan, as amended effective on May 1, 2007 (Exhibit 10.1 to Form 8-K filed on May 4, 2007).	Great Plains Energy KCP&L
10.3	*+	Great Plains Energy Incorporated Amended Long-Term Incentive Plan, as amended effective on May 3, 2011 (Exhibit 10.1 to Form 8-K filed on May 6, 2011).	Great Plains Energy KCP&L
10.4	*+	Great Plains Energy Incorporated Amended Long-Term Incentive Plan, as amended effective on January 1, 2014 (Exhibit 10.1 to Form 10-Q for the quarter ended June 30, 2013).	Great Plains Energy KCP&L
10.5	*+	Great Plains Energy Incorporated Amended Long-Term Incentive Plan, as amended effective on May 3, 2016 (Exhibit 10.4 to Form 10-Q for the quarter ended June 30, 2016).	Great Plains Energy KCP&L
10.6	*+	Great Plains Energy Incorporated Long-Term Incentive Plan Awards Standards and Performance Criteria Effective as of January 1, 2013 (Exhibit 10.3 to Form 10-Q for the quarter ended March 31, 2013).	Great Plains Energy KCP&L
10.7	*+	Great Plains Energy Incorporated Long-Term Incentive Plan Awards Standards and Performance Criteria Effective as of January 1, 2014 (Exhibit 10.3 to Form 10-Q for the quarter ended March 31, 2014).	Great Plains Energy KCP&L
10.8	*+	Great Plains Energy Incorporated Long-Term Incentive Plan Awards Standards and Performance Criteria Effective as of January 1, 2015 (Exhibit 10.3 to Form 10-Q for the quarter ended March 31, 2015).	Great Plains Energy KCP&L
10.9	*+	Great Plains Energy Incorporated Long-Term Incentive Plan Awards Standards and Performance Criteria Effective as of January 1, 2016 (Exhibit 10.3 to Form 10-Q for the quarter ended March 31, 2016).	Great Plains Energy KCP&L
10.10	*+	Form of 2013 three-year Performance Share Agreement (Exhibit 10.1 to Form 10-Q for the quarter ended March 31, 2013).	Great Plains Energy KCP&L
10.11	*+	Form of 2013 Restricted Stock Agreement (Exhibit 10.2 to Form 10-Q for the quarter ended March 31, 2013).	Great Plains Energy KCP&L
10.12	*+	Form of 2014 three-year Performance Share Agreement (Exhibit 10.1 to Form 10-Q for the quarter ended March 31, 2014).	Great Plains Energy KCP&L
10.13	*+	Form of 2014 Restricted Stock Agreement (Exhibit 10.2 to Form 10-Q for the quarter ended March 31, 2014).	Great Plains Energy KCP&L
10.14	*+	Form of 2015 three-year Performance Share Agreement (Exhibit 10.1 to Form 10-Q for the quarter ended March 31, 2015).	Great Plains Energy KCP&L
10.15	*+	Form of 2015 Restricted Stock Agreement (Exhibit 10.2 to Form 10-Q for the quarter ended March 31, 2015).	Great Plains Energy KCP&L
10.16	*+	Form of 2016 three-year Performance Share Agreement (Exhibit 10.1 to Form 10-Q for the quarter ended March 31, 2016).	Great Plains Energy KCP&L

10.17	*+	Form of 2016 Restricted Stock Agreement (Exhibit 10.2 to Form 10-Q for the quarter ended March 31, 2016).	Great Plains Energy KCP&L
10.18	*+	Aquila, Inc. 2002 Omnibus Incentive Compensation Plan (Exhibit 10.3 to Form 10-Q for the quarter ended September 30, 2002, filed by Aquila, Inc.).	Great Plains Energy
10.19	*+	Great Plains Energy Incorporated, Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company Annual Incentive Plan amended effective as of January 1, 2016 (Exhibit 10.4 to Form 10-Q for the quarter ended March 31, 2016).	Great Plains Energy KCP&L
10.20	*+	Form of Indemnification Agreement with each officer and director (Exhibit 10-f to Form 10-K for year ended December 31, 1995).	Great Plains Energy KCP&L
10.21	*+	Form of Conforming Amendment to Indemnification Agreement with each officer and director (Exhibit 10.1.a to Form 10-Q for the quarter ended March 31, 2003).	Great Plains Energy KCP&L
10.22	*+	Form of Indemnification Agreement with each director and officer (Exhibit 10.1 to Form 8-K filed on December 8, 2008).	Great Plains Energy KCP&L
10.23	*+	Form of Indemnification Agreement with officers and directors (Exhibit 10.1.p to Form 10-K for the year ended December 31, 2005).	Great Plains Energy KCP&L
10.24	*+	Form of Indemnification Agreement with officers and directors (Exhibit 10.1 to Form 8-K filed on December 16, 2013).	Great Plains Energy KCP&L
10.25	*+	Form of Change in Control Severance Agreement with other executive officers of Great Plains Energy Incorporated and Kansas City Power & Light Company (Exhibit 10.1.e to Form 10-Q for the quarter ended September 30, 2006).	Great Plains Energy KCP&L
10.26	*+	Great Plains Energy Incorporated Supplemental Executive Retirement Plan (As Amended and Restated for I.R.C. §409A) (Exhibit 10.1.10 to Form 10-Q for the quarter ended September 30, 2007).	Great Plains Energy KCP&L
10.27	*+	Great Plains Energy Incorporated Supplemental Executive Retirement Plan (As Amended and Restated for I.R.C. §409A), as amended February 10, 2009 (Exhibit 10.1.29 to Form 10-K for the year ended December 31, 2008	Great Plains Energy KCP&L
10.28	*+	Great Plains Energy Incorporated Supplemental Executive Retirement Plan (As Amended and Restated for I.R.C. §409A), as amended December 8, 2009 (Exhibit 10.1.27 to Form 10-K for the year ended December 31, 2009).	Great Plains Energy KCP&L
10.29	*+	Amendment dated October 28, 2014, to the Great Plains Energy Incorporated Supplemental Executive Retirement Plan as amended and restated on December 8, 2009 (Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 2014).	Great Plains Energy KCP&L

10.30	*+	Great Plains Energy Incorporated Nonqualified Deferred Compensation Plan (As Amended and Restated for I.R.C. §409A) (Exhibit 10.1.11 to Form 10-Q for the quarter ended September 30, 2007).	Great Plains Energy KCP&L
10.31	*+	Great Plains Energy Incorporated Nonqualified Deferred Compensation Plan (As Amended and Restated for I.R.C. §409A), amended effective January 1, 2010 (Exhibit 10.1.5 to Form 10-Q for the quarter ended March 31, 2010).	Great Plains Energy KCP&L
10.32	*	Joint Motion and Settlement Agreement, dated as of February 26, 2008, among Great Plains Energy Incorporated, Kansas City Power & Light Company, the Kansas Corporation Commission Staff, the Citizens' Utility Ratepayers Board, Aquila, Inc. d/b/a Aquila Networks, Black Hills Corporation, and Black Hills/ Kansas Gas Utility Company, LLC (Exhibit 10.1.7 to Form 10-Q for the quarter ended March 31, 2008).	Great Plains Energy KCP&L
10.33	*	Credit Agreement, dated as of August 9, 2010, among Great Plains Energy Incorporated, Certain Lenders, Bank of America, N.A., as Administrative Agent, and Union Bank, N.A. and Wells Fargo Bank, National Association, as Syndication Agents, Barclays Bank PLC and U.S. Bank National Association, as Documentation Agents, Banc of America Securities LLC, Union Bank, N.A. and Wells Fargo Securities, LLC as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 2010).	Great Plains Energy
10.34	*	First Amendment to Credit Agreement, dated as of December 9, 2011, among Great Plains Energy Incorporated, Certain Lenders, Union Bank, N.A. and Wells Fargo Bank, National Association, as Syndication Agents, Bank of America, N.A., as Administrative Agent, Barclays Bank PLC and U.S. Bank National Association, as Documentation Agents, Merrill Lynch, Pierce, Fenner & Smith Incorporated, Union Bank, N.A. and Wells Fargo Securities, LLC as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.59 to Form 10-K for the year ended December 31, 2011).	Great Plains Energy
10.35	*	Second Amendment to Credit Agreement, dated as of October 17, 2013, among Great Plains Energy Incorporated, Certain Lenders, Bank of America, N.A., JPMorgan Chase Bank, N.A. and Union Bank, N.A., as Syndication Agents and Wells Fargo Bank, National Association, as Administrative Agent, and Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, J.P. Morgan Securities LLC, and Union Bank, N.A., as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 2013).	Great Plains Energy
10.36	*	First Extension Agreement and Waiver, dated as of December 17, 2014, among Great Plains Energy Incorporated, Certain Lenders, Bank of America, N.A., JPMorgan Chase Bank, N.A., and MUFG Union Bank, N.A., as Syndication Agents and Wells Fargo Bank, National Association, as Administrative Agent, Swing Line Lender and an Issuer, Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, J.P. Morgan Securities LLC, and MUFG Union Bank, N.A., as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.37 to Form 10-K for the year ended December 31, 2014).	Great Plains Energy

10.37	*	Third Amendment to the Credit Agreement, dated as of June 13, 2016, among Great Plains Energy Incorporated, Certain Lenders, Bank of America, N.A., JPMorgan Chase Bank, N.A., and Union Bank, N.A., as Syndication Agents and Wells Fargo Bank, National Association, as Administrative Agent, and Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, J.P. Morgan Securities LLC, and Union Bank, N.A., as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.1 to Form 10-Q for the quarter ended June 30, 2016).	Great Plains Energy
10.38	*	Credit Agreement, dated as of August 9, 2010, among Kansas City Power & Light Company, Certain Lenders, Bank of America, N.A., as Administrative Agent, and Union Bank, N.A. and Wells Fargo Bank, National Association, as Syndication Agents, JPMorgan Chase Bank, N.A. and The Bank of Nova Scotia, as Documentation Agents, Banc of America Securities LLC, Union Bank, N.A. and Wells Fargo Securities, LLC as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.2 to Form 10-Q for the quarter ended September 30, 2010).	Great Plains Energy KCP&L
10.39	*	First Amendment to Credit Agreement, dated as of December 9, 2011, among Kansas City Power & Light Company, Certain Lenders, Union Bank, N.A. and Wells Fargo Bank, National Association, as Syndication Agents, Bank of America, N.A., as Administrative Agent, JPMorgan Chase Bank, N.A. and The Bank of Nova Scotia, as Documentation Agents, Merrill Lynch, Pierce, Fenner & Smith Incorporated, Union Bank, N.A. and Wells Fargo Securities, LLC as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.61 to Form 10-K for the year ended December 31, 2011).	Great Plains Energy KCP&L
10.40	*	Second Amendment to Credit Agreement, dated as of October 17, 2013, among Kansas City Power & Light Company, Certain Lenders, Bank of America, N.A., JPMorgan Chase Bank, N.A., and Union Bank, N.A., as Syndication Agents and Wells Fargo Bank, National Association, as Administrative Agent, and Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, J.P. Morgan Securities LLC, and Union Bank, N.A., as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.2 to Form 10-Q for the quarter ended September 30, 2013).	Great Plains Energy KCP&L
10.41	*	First Extension Agreement and Waiver, dated as of December 17, 2014, among Kansas City Power & Light Company, Certain Lenders, Bank of America, N.A., JPMorgan Chase Bank, N.A., and MUFG Union Bank, N.A., as Syndication Agents and Wells Fargo Bank, National Association, as Administrative Agent, Swing Line Lender and an Issuer, Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, J.P. Morgan Securities LLC, and MUFG Union Bank, N.A., as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.41 to Form 10-K for the year ended December 31, 2014).	Great Plains Energy KCP&L

10.42	*	Credit Agreement, dated as of August 9, 2010, among KCP&L Greater Missouri Operations Company, Great Plains Energy Incorporated, as Guarantor, Certain Lenders, Bank of America, N.A., as Administrative Agent, and Union Bank, N.A. and Wells Fargo Bank, National Association, as Syndication Agents, The Royal Bank of Scotland PLC and BNP Paribas , as Documentation Agents, Banc of America Securities LLC, Union Bank, N.A. and Wells Fargo Securities, LLC as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.3 to Form 10-Q for the quarter ended September 30, 2010).	Great Plains Energy
10.43	*	First Amendment to Credit Agreement, dated as of December 9, 2011, among KCP&L Greater Missouri Operations Company, Great Plains Energy Incorporated, as Guarantor, Certain Lenders, Union Bank, N.A. and Wells Fargo Bank, National Association, as Syndication Agents, Bank of America, N.A., as Administrative Agent, The Royal Bank of Scotland PLC and BNP Paribas, as Documentation Agents, Merrill Lynch, Pierce, Fenner & Smith Incorporated, Union Bank, N.A. and Wells Fargo Securities, LLC as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.63 to Form 10-K for the year ended December 31, 2011).	Great Plains Energy
10.44	*	Second Amendment to Credit Agreement, dated as of October 17, 2013, among KCP&L Greater Missouri Operations Company, Certain Lenders, Bank of America, N.A., JPMorgan Chase Bank, N.A., and Union Bank, N.A., as Syndication Agents and Wells Fargo Bank, National Association, as Administrative Agent, and Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, J.P. Morgan Securities LLC, and Union Bank, N.A., as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.3 to Form 10-Q for the quarter ended September 30, 2013).	Great Plains Energy
10.45	*	First Extension Agreement and Waiver, dated as of December 17, 2014, among KCP&L Greater Missouri Operations Company, Certain Lenders, Bank of America, N.A., JPMorgan Chase Bank, N.A., and MUFG Union Bank, N.A., as Syndication Agents and Wells Fargo Bank, National Association, as Administrative Agent, Swing Line Lender and an Issuer, Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, J.P. Morgan Securities LLC, and MUFG Union Bank, N.A., as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.45 to Form 10-K for the year ended December 31, 2014).	Great Plains Energy
10.46	*	Guaranty, dated as of July 15, 2008, issued by Great Plains Energy Incorporated in favor of Union Bank of California, N.A., as successor trustee, and the holders of the Aquila, Inc., 8.27% Senior Notes due November 15, 2021 (Exhibit 10.6 to Form 8-K filed on July 18, 2008).	Great Plains Energy
10.47	*	Insurance Agreement, dated as of September 1, 2005, between Kansas City Power & Light Company and XL Capital Assurance Inc. (Exhibit 10.2.e to Form 10-K for the year ended December 31, 2005).	Great Plains Energy KCP&L
10.48	*	Insurance Agreement, dated as of September 1, 2005, between Kansas City Power & Light Company and XL Capital Assurance Inc. (Exhibit 10.2.f to Form 10-K for the year ended December 31, 2005).	Great Plains Energy KCP&L

10.49	*	Purchase and Sale Agreement, dated as of July 1, 2005, between Kansas City Power & Light Company, as Originator, and Kansas City Power & Light Receivables Company, as Buyer (Exhibit 10.2.b to Form 10-Q for the quarter ended June 30, 2005).	Great Plains Energy KCP&L
10.50	*	Receivables Sale Agreement, dated as of July 1, 2005, among Kansas City Power & Light Receivables Company, as the Seller, Kansas City Power & Light Company, as the Initial Collection Agent, The Bank of Tokyo-Mitsubishi, Ltd., New York Branch, as the Agent, and Victory Receivables Corporation (Exhibit 10.2.c to Form 10-Q for the quarter ended June 30, 2005).	Great Plains Energy KCP&L
10.51	*	Amendment No. 1, dated as of April 2, 2007, among Kansas City Power & Light Receivables Company, Kansas City Power & Light Company, The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch and Victory Receivables Corporation to the Receivables Sale Agreement dated as of July 1, 2005 (Exhibit 10.2.2 to Form 10-Q for the quarter ended March 31, 2007).	Great Plains Energy KCP&L
10.52	*	Amendment No. 2, dated as of July 11, 2008, among Kansas City Power & Light Receivables Company, Kansas City Power & Light Company, The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch and Victory Receivables Corporation to the Receivables Sale Agreement dated as of July 1, 2005 (Exhibit 10.2.2 to Form 10-Q for the quarter ended June 30, 2008).	Great Plains Energy KCP&L
10.53	*	Amendment, dated as of July 9, 2009, to Receivables Sale Agreement dated as of July 1, 2005 among Kansas City Power & Light Receivables Company, Kansas City Power & Light Company, The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch and Victory Receivables Corporation (Exhibit 10.4 to Form 8-K filed on July 13, 2009).	Great Plains Energy KCP&L
10.54	*	Amendment and Waiver, dated as of September 25, 2009, to the Receivables Sale Agreement dated as of July 1, 2005 among Kansas City Power & Light Receivables Company, Kansas City Power & Light Company, The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch and Victory Receivables Corporation (Exhibit 10.2.2 to Form 10-Q for the quarter ended September 30, 2009).	Great Plains Energy KCP&L
10.55	*	Amendment, dated as of May 5, 2010, to Receivables Sale Agreement dated as of July 1, 2005 among Kansas City Power & Light Receivables Company, Kansas City Power & Light Company, The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch and Victory Receivables Corporation (Exhibit 10.2.2 to Form 10-Q for the quarter ended March 31, 2010).	Great Plains Energy KCP&L
10.56	*	Amendment, dated as of February 23, 2011, to Receivables Sale Agreement dated as of July 1, 2005 among Kansas City Power & Light Receivables Company, Kansas City Power & Light Company, The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch and Victory Receivables Corporation. (Exhibit 10.5 to Form 10-Q for the quarter ended March 31, 2011).	Great Plains Energy KCP&L

10.57	*	Amendment, dated as of September 9, 2011, to Receivables Sale Agreement dated as of July 1, 2005, among Kansas City Power & Light Receivables Company, Kansas City Power & Light Company, The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch and Victory Receivables Corporation (Exhibit 10.1 to Form 8-K filed on September 13, 2011).	Great Plains Energy KCP&L
10.58	*	Amendment dated as of September 9, 2014, to the Receivables Sales Agreement dated as of July 1, 2005, among Kansas City Power & Light Receivables Company, as the Seller, Kansas City Power & Light Company, as the Initial Collection Agent, The Bank of Tokyo-Mitsubishi, Ltd., New York Branch, as the Agent and Victory Receivables Corporation, as the Purchaser (Exhibit 10.1 to Form 8-K filed on September 15, 2014).	Great Plains Energy KCP&L
10.59	*	Amendment dated as of September 9, 2015, to the Receivables Sales Agreement dated as of July 1, 2005, among Kansas City Power & Light Receivables Company, as the Seller, Kansas City Power & Light Company, as the Initial Collection Agent, The Bank of Tokyo-Mitsubishi, Ltd., New York Branch, as the Agent and Victory Receivables Corporation, as the Purchaser (Exhibit 10.1 to Form 8-K filed on September 11, 2015).	Great Plains Energy KCP&L
10.60	*	Amendment dated as of September 9, 2016, to the Receivables Sales Agreement dated as of July 1, 2005, among Kansas City Power & Light Receivables Company, as the Seller, Kansas City Power & Light Company, as the Initial Collection Agent, The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch, as the Agent and Victory Receivables Corporation, as the Purchaser (Exhibit 10.1 to Form 8-K filed on September 13, 2016).	Great Plains Energy KCP&L
10.61	*	Purchase and Sale Agreement, dated as of May 31, 2012, between KCP&L Greater Missouri Operations Company, as Originator, and GMO Receivables Company, as Buyer (Exhibit 10.2. to Form 10-Q for the quarter ended June 30, 2012).	Great Plains Energy
10.62	*	Receivables Sale Agreement, dated as of May 31, 2012, among GMO Receivables Company, as the Seller, KCP&L Greater Missouri Operations Company, as the Initial Collection Agent, The Bank of Tokyo-Mitsubishi, Ltd., New York Branch, as the Agent, and Victory Receivables Corporation (Exhibit 10.3 to Form 10-Q for the quarter ended June 30, 2012).	Great Plains Energy
10.63	*	First Amendment dated as of September 9, 2014, to the Receivables Sales Agreement dated as of May 31, 2012, among GMO Receivables Company, as the Seller, KCP&L Greater Missouri Operations Company, as the Initial Collection Agent, The Bank of Tokyo-Mitsubishi, Ltd., New York Branch, as the Agent and Victory Receivables Corporation, as the Purchaser. (Exhibit 10.2 to Form 8-K filed on September 15, 2014).	Great Plains Energy
10.64	*	Second Amendment dated as of September 9, 2015, to the Receivables Sales Agreement dated as of May 31, 2012, among GMO Receivables Company, as the Seller, KCP&L Greater Missouri Operations Company, as the Initial Collection Agent, The Bank of Tokyo-Mitsubishi, Ltd., New York Branch, as the Agent and Victory Receivables Corporation, as the Purchaser. (Exhibit 10.2 to Form 8-K filed on September 11, 2015).	Great Plains Energy

10.65	*	Third Amendment dated as of September 9, 2016, to the Receivables Sales Agreement dated as of May 31, 2012, among GMO Receivables Company, as the Seller, KCP&L Greater Missouri Operations Company, as the Initial Collection Agent, The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch, as the Agent and Victory Receivables Corporation, as the Purchaser (Exhibit 10.2 to Form 8-K filed September 13, 2016).	Great Plains Energy
10.66	*	Iatan Unit 2 and Common Facilities Ownership Agreement, dated as of May 19, 2006, among Kansas City Power & Light Company, Aquila, Inc., The Empire District Electric Company, Kansas Electric Power Cooperative, Inc., and Missouri Joint Municipal Electric Utility Commission (Exhibit 10.2.a to Form 10-Q for the quarter ended June 30, 2006).	Great Plains Energy KCP&L
10.67	*	Joint Motion and Settlement Agreement dated as of February 26, 2008, among Great Plains Energy Incorporated, Kansas City Power & Light Company, the Kansas Corporation Commission Staff, the Citizens' Utility Ratepayers Board, Aquila, Inc. d/b/a Aquila Networks, Black Hills Corporation, and Black Hills/ Kansas Gas Utility Company, LLC (Exhibit 10.1.7 to Form 10-Q for the quarter ended March 31, 2008).	Great Plains Energy KCP&L
10.68	*	Stipulation and Agreement dated April 24, 2009, among Kansas City Power & Light Company, Staff of the Missouri Public Service Commission, Office of Public Counsel, Praxair, Inc., Midwest Energy Users Association, U.S. Department of Energy and the U.S. Nuclear Security Administration, Ford Motor Company, Missouri Industrial Energy Consumers and Missouri Department of Natural Resources (Exhibit 10.1 to Form 8-K filed April 30, 2009).	Great Plains Energy KCP&L
10.69	*	Non-Unanimous Stipulation and Agreement dated May 22, 2009 among KCP&L Greater Missouri Operations Company, the Staff of the Missouri Public Service Commission, the Office of the Public Counsel, Missouri Department of Natural Resources and Dogwood Energy, LLC (Exhibit 10.1 to Form 8-K filed on May 27, 2009).	Great Plains Energy
10.70	*	Collaboration Agreement dated as of March 19, 2007, among Kansas City Power & Light Company, Sierra Club and Concerned Citizens of Platte County, Inc. (Exhibit 10.1 to Form 8-K filed on March 20, 2007).	Great Plains Energy KCP&L
10.71	*	Amendment to the Collaboration Agreement effective as of September 5, 2008 among Kansas City Power & Light Company, Sierra Club and Concerned Citizens of Platte County, Inc. (Exhibit 10.2.20 to Form 10-K for the year ended December 31, 2009).	Great Plains Energy KCP&L
10.72	*	Joint Operating Agreement between Kansas City Power & Light Company and Aquila, Inc., dated as of October 10, 2008 (Exhibit 10.2.2 to Form 10-Q for the quarter ended September 30, 2008).	Great Plains Energy KCP&L
10.73	*	Commitment letter, dated as of May 29, 2016, by Goldman Sachs Bank USA and Goldman Sachs Lending Partners LLC to Great Plains Energy Incorporated (Exhibit 10.1 to Form 8-K filed on May 31, 2016).	Great Plains Energy

10.74	*	Stock Purchase Agreement, dated as of May 29, 2016, by and between OCM Credit Portfolio LP and Great Plains Energy Incorporated (Exhibit 10.2 to Form 8-K filed on May 31, 2016).	Great Plains Energy
12.1		Computation of Ratios of Earnings to Fixed Charges and Earnings to Combined Fixed Charges and Preferred Dividend Requirements.	Great Plains Energy
12.2		Computation of Ratio of Earnings to Fixed Charges.	KCP&L
21.1		List of Subsidiaries of Great Plains Energy Incorporated.	Great Plains Energy
23.1		Consent of Independent Registered Public Accounting Firm.	Great Plains Energy
23.2		Consent of Independent Registered Public Accounting Firm.	KCP&L
24.1		Powers of Attorney.	Great Plains Energy
24.2		Powers of Attorney.	KCP&L
31.1		Rule 13a-14(a)/15d-14(a) Certification of Terry Bassham.	Great Plains Energy
31.2		Rule 13a-14(a)/15d-14(a) Certification of Kevin E. Bryant.	Great Plains Energy
31.3		Rule 13a-14(a)/15d-14(a) Certification of Terry Bassham.	KCP&L
31.4		Rule 13a-14(a)/15d-14(a) Certification of Kevin E. Bryant.	KCP&L
32.1	**	Section 1350 Certifications.	Great Plains Energy
32.2	**	Section 1350 Certifications.	KCP&L
101.INS		XBRL Instance Document.	Great Plains Energy KCP&L
101.SCH		XBRL Taxonomy Extension Schema Document.	Great Plains Energy KCP&L
101.CAL		XBRL Taxonomy Extension Calculation Linkbase Document.	Great Plains Energy KCP&L
101.DEF		XBRL Taxonomy Extension Definition Linkbase Document.	Great Plains Energy KCP&L
101.LAB		XBRL Taxonomy Extension Labels Linkbase Document.	Great Plains Energy KCP&L
101.PRE		XBRL Taxonomy Extension Presentation Linkbase Document.	Great Plains Energy KCP&L

* Filed with the SEC as exhibits to prior SEC filings and are incorporated herein by reference and made a part hereof. The SEC filings and the exhibit number of the documents so filed, and incorporated herein by reference, are stated in parenthesis in the description of such exhibit.

** Furnished and shall not be deemed filed for the purpose of Section 18 of the Securities Exchange Act of 1934, as amended (the Exchange Act). Such document shall not be incorporated by reference into any registration statement or other document pursuant to the Exchange Act or the Securities Act of 1933, as amended, unless otherwise indicated in such registration statement or other document.

+ Indicates management contract or compensatory plan or arrangement.

Copies of any of the exhibits filed with the SEC in connection with this document may be obtained from KCP&L upon written request.

The registrants agree to furnish to the SEC upon request any instrument with respect to long-term debt as to which the total amount of securities authorized does not exceed 10% of total assets of such registrant and its subsidiaries on a consolidated basis.

Schedule I - Parent Company Financial Statements

GREAT PLAINS ENERGY INCORPORATED

Statements of Comprehensive Income of Parent Company

Year Ended December 31	2016	2015	2014
Operating Expenses	(millions, except per share amounts)		
General and administrative	**$ 2.7**	$ 0.9	$ 1.1
Costs to achieve the acquisition of Westar Energy, Inc.	**18.3**	—	—
General taxes	**0.1**	0.2	0.4
Total	**21.1**	1.1	1.5
Operating loss	**(21.1)**	(1.1)	(1.5)
Equity in earnings from subsidiaries	**287.5**	220.9	251.1
Non-operating income	**31.3**	29.7	33.1
Interest (charges) income	**2.6**	(40.3)	(44.3)
Income before income taxes	**300.3**	209.2	238.4
Income tax (expense) benefit	**(10.3)**	3.8	4.4
Net income	**290.0**	213.0	242.8
Preferred stock dividend requirements and redemption premium	**16.5**	1.6	1.6
Earnings available for common shareholders	**$ 273.5**	$ 211.4	$ 241.2
Average number of basic common shares outstanding	**169.4**	154.2	153.9
Average number of diluted common shares outstanding	**169.8**	154.8	154.1
Basic and diluted earnings per common share	**$ 1.61**	$ 1.37	$ 1.57
Comprehensive Income			
Net income	**$ 290.0**	$ 213.0	$ 242.8
Other comprehensive income			
Derivative hedging activity			
Reclassification to expenses	**0.4**	0.5	4.4
Income tax expense	**(0.2)**	(0.1)	(1.7)
Net reclassification to expenses	**0.2**	0.4	2.7
Derivative hedging activity, net of tax	**0.2**	0.4	2.7
Other comprehensive income from subsidiaries, net of tax	**5.2**	6.3	3.9
Total other comprehensive income	**5.4**	6.7	6.6
Comprehensive income	**$ 295.4**	$ 219.7	$ 249.4

The accompanying Notes to Financial Statements of Parent Company are an integral part of these statements.

GREAT PLAINS ENERGY INCORPORATED

Balance Sheets of Parent Company

	December 31	
	2016	2015
ASSETS	(millions, except share amounts)	
Current Assets		
Cash and cash equivalents	**$ 1,283.9**	$ —
Time deposit	**1,000.0**	—
Accounts receivable from subsidiaries	**10.6**	4.1
Notes receivable from subsidiaries	**2.0**	2.0
Money pool receivable	**—**	3.7
Derivative instruments	**79.3**	—
Other	**26.1**	0.4
Total	**2,401.9**	10.2
Investments and Other Assets		
Investment in KCP&L	**2,541.5**	2,433.1
Investment in other subsidiaries	**1,341.6**	1,385.9
Note receivable from subsidiaries	**634.9**	634.9
Deferred income taxes	**12.8**	34.8
Other	**16.3**	1.6
Total	**4,547.1**	4,490.3
Total	**$ 6,949.0**	$ 4,500.5
LIABILITIES AND CAPITALIZATION		
Current Liabilities		
Notes payable	**$ —**	$ 10.0
Current maturities of long-term debt	**100.0**	—
Accounts payable to subsidiaries	**10.8**	31.7
Accrued taxes	**12.9**	4.5
Accrued interest	**10.1**	4.1
Other	**12.8**	9.5
Total	**146.6**	59.8
Deferred Credits and Other Liabilities	**2.2**	7.1
Capitalization		
Great Plains Energy shareholders' equity		
Common stock - 600,000,000 and 250,000,000 shares authorized without par value 215,479,105 and 154,504,900 shares issued, stated value	**4,217.0**	2,646.7
Cumulative preferred stock - 390,000 shares authorized, $100 par value 0 and 390,000 shares issued and outstanding	**—**	39.0
Preference stock - 11,000,000 shares authorized without par value 7.00% Series B Mandatory Convertible Preferred Stock $1,000 per share liquidation preference, 862,500 and 0 shares issued and outstanding	**836.2**	—
Retained earnings	**1,119.2**	1,024.4
Treasury stock - 128,087 and 101,229 shares, at cost	**(3.8)**	(2.6)
Accumulated other comprehensive loss	**(6.6)**	(12.0)
Total shareholders' equity	**6,162.0**	3,695.5
Long-term debt	**638.2**	738.1
Total	**6,800.2**	4,433.6
Commitments and Contingencies		
Total	**$ 6,949.0**	$ 4,500.5

The accompanying Notes to Financial Statements of Parent Company are an integral part of these statements.

GREAT PLAINS ENERGY INCORPORATED
Statements of Cash Flows of Parent Company

Year Ended December 31	2016	2015	2014
Cash Flows from Operating Activities		(millions)	
Net income	**$ 290.0**	$ 213.0	$ 242.8
Adjustments to reconcile income to net cash from operating activities:			
Amortization	**30.4**	0.8	4.8
Deferred income taxes, net	**21.8**	(1.7)	(1.4)
Fair value impact of interest rate swaps	**(79.3)**	—	—
Equity in earnings from subsidiaries	**(287.5)**	(220.9)	(251.1)
Cash flows affected by changes in:			
Accounts receivable from subsidiaries	**(9.8)**	(0.1)	(3.8)
Taxes receivable	**—**	—	0.2
Accounts payable to subsidiaries	**(20.9)**	1.3	(3.2)
Other accounts payable	**7.0**	—	—
Accrued taxes	**8.4**	0.3	4.3
Accrued interest	**6.0**	—	(0.1)
Cash dividends from subsidiaries	**239.0**	157.0	144.0
Uncertain tax positions	**(0.4)**	—	(2.9)
Other	**8.4**	8.7	11.8
Net cash from operating activities	**213.1**	158.4	145.4
Cash Flows from Investing Activities			
Purchase of time deposit	**(1,000.0)**	—	—
Intercompany lending	**—**	(1.4)	—
Net money pool lending	**3.7**	(0.4)	6.1
Investment in subsidiary	**(7.3)**	(7.8)	(3.6)
Net cash from investing activities	**(1,003.6)**	(9.6)	2.5
Cash Flows from Financing Activities			
Issuance of common stock	**1,603.7**	3.0	4.8
Issuance of preference stock	**862.5**	—	—
Issuance fees	**(143.4)**	—	(0.1)
Net change in short-term borrowings	**(10.0)**	6.0	(5.0)
Dividends paid	**(194.0)**	(155.5)	(145.6)
Redemption of cumulative preferred stock	**(40.1)**	—	—
Purchase of treasury stock	**(5.0)**	(1.6)	(2.5)
Other financing activities	**0.7**	(0.7)	0.5
Net cash from financing activities	**2,074.4**	(148.8)	(147.9)
Net Change in Cash and Cash Equivalents	**1,283.9**	—	—
Cash and Cash Equivalents at Beginning of Year	**—**	—	—
Cash and Cash Equivalents at End of Year	**$ 1,283.9**	$ —	$ —

The accompanying Notes to Financial Statements of Parent Company are an integral part of these statements.

GREAT PLAINS ENERGY INCORPORATED
NOTES TO FINANCIAL STATEMENTS OF PARENT COMPANY

The Great Plains Energy Incorporated Notes to Consolidated Financial Statements in Part II, Item 8 should be read in conjunction with the Great Plains Energy Incorporated Parent Company Financial Statements.

The Great Plains Energy Incorporated Parent Company Financial Statements have been prepared to present the financial position, results of operations and cash flows of Great Plains Energy on a stand-alone basis as a holding company. Investments in subsidiaries are accounted for using the equity method.

Schedule II - Valuation and Qualifying Accounts and Reserves

Great Plains Energy Incorporated
Valuation and Qualifying Accounts
Years Ended December 31, 2016, 2015 and 2014

Description	Balance At Beginning Of Period	Additions: Charged To Costs And Expenses	Additions: Charged To Other Accounts	Deductions	Balance At End Of Period
Year Ended December 31, 2016			(millions)		
Allowance for uncollectible accounts	$ 3.8	$ 9.0	$ 8.1 [a]	$ 16.9 [b]	$ 4.0
Legal reserves	5.9	10.4	—	0.2 [c]	16.1
Environmental reserves	1.7	—	—	—	1.7
Tax valuation allowance	19.9	0.1	—	3.6 [d]	16.4
Year Ended December 31, 2015					
Allowance for uncollectible accounts	$ 2.8	$ 10.5	$ 8.7 [a]	$ 18.2 [b]	$ 3.8
Legal reserves	4.7	2.6	—	1.4 [c]	5.9
Environmental reserves	1.7	—	—	—	1.7
Tax valuation allowance	16.6	4.9	—	1.6 [d]	19.9
Year Ended December 31, 2014					
Allowance for uncollectible accounts	$ 2.5	$ 11.4	$ 8.5 [a]	$ 19.6 [b]	$ 2.8
Legal reserves	4.6	2.7	—	2.6 [c]	4.7
Environmental reserves	1.7	—	—	—	1.7
Tax valuation allowance	20.7	0.5	—	4.6 [d]	16.6

(a) Recoveries.
(b) Uncollectible accounts charged off.
(c) Payment of claims.
(d) Reversal of tax valuation allowance.

Kansas City Power & Light Company
Valuation and Qualifying Accounts
Years Ended December 31, 2016, 2015 and 2014

		Additions			
Description	Balance At Beginning Of Period	Charged To Costs And Expenses	Charged To Other Accounts	Deductions	Balance At End Of Period
Year Ended December 31, 2016			(millions)		
Allowance for uncollectible accounts	$ 1.8	$ 6.4	$ 5.5 (a)	$ 11.9 (b)	$ 1.8
Legal reserves	5.3	9.8	—	— (c)	15.1
Environmental reserves	0.3	—	—	—	0.3
Tax valuation allowance	0.7	—	—	0.7 (d)	—
Year Ended December 31, 2015					
Allowance for uncollectible accounts	$ 1.2	$ 7.1	$ 5.8 (a)	$ 12.3 (b)	$ 1.8
Legal reserves	2.9	2.6	—	0.2 (c)	5.3
Environmental reserves	0.3	—	—	—	0.3
Tax valuation allowance	—	0.7	—	—	0.7
Year Ended December 31, 2014					
Allowance for uncollectible accounts	$ 1.1	$ 7.6	$ 5.5 (a)	$ 13.0 (b)	$ 1.2
Legal reserves	2.9	2.3	—	2.3 (c)	2.9
Environmental reserves	0.3	—	—	—	0.3

(a) Recoveries.
(b) Uncollectible accounts charged off.
(c) Payment of claims.
(d) Reversal of tax valuation allowance.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

GREAT PLAINS ENERGY INCORPORATED

Date: February 23, 2017

By: /s/ Terry Bassham
Terry Bassham
Chairman, President and Chief Executive Officer

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

Signature	Title	Date
/s/ Terry Bassham Terry Bassham	Chairman, President and Chief Executive Officer (Principal Executive Officer)	February 23, 2017
/s/ Kevin E. Bryant Kevin E. Bryant	Senior Vice President - Finance and Strategy and Chief Financial Officer (Principal Financial Officer)	
/s/ Steven P. Busser Steven P. Busser	Vice President - Risk Management and Controller (Principal Accounting Officer)	
David L. Bodde*	Director	
Randall C. Ferguson, Jr.*	Director	
Gary D. Forsee*	Director	
Scott D. Grimes*	Director	
Thomas D. Hyde*	Director	
James A. Mitchell*	Director	
Ann D. Murtlow*	Director	
Sandra J. Price*	Director	
John J. Sherman*	Director	

*By /s/ Terry Bassham
Terry Bassham
Attorney-in-Fact*

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

KANSAS CITY POWER & LIGHT COMPANY

Date: February 23, 2017

By: /s/ Terry Bassham
Terry Bassham
Chairman, President and Chief Executive Officer

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

Signature	Title	Date
/s/ Terry Bassham Terry Bassham	Chairman, President and Chief Executive Officer (Principal Executive Officer)	February 23, 2017
/s/ Kevin E. Bryant Kevin E. Bryant	Senior Vice President - Finance and Strategy and Chief Financial Officer (Principal Financial Officer)	
/s/ Steven P. Busser Steven P. Busser	Vice President - Risk Management and Controller (Principal Accounting Officer)	
David L. Bodde*	Director	
Randall C. Ferguson, Jr.*	Director	
Gary D. Forsee*	Director	
Scott D. Grimes*	Director	
Thomas D. Hyde*	Director	
James A. Mitchell*	Director	
Ann D. Murtlow*	Director	
Sandra J. Price*	Director	
John J. Sherman*	Director	

*By /s/ Terry Bassham
Terry Bassham
Attorney-in-Fact*

DIRECTORS AND OFFICERS

BOARD OF DIRECTORS Great Plains Energy

TERRY BASSHAM
Chairman of the Board, President and Chief Executive Officer

DR. DAVID L. BODDE
Professor Emeritus, Clemson University

RANDALL C. FERGUSON, JR.
Former Senior Partner for Business Development, Tshibanda & Associates, LLC, a consulting and project management services firm

GARY D. FORSEE
Former President, University of Missouri System

SCOTT D. GRIMES
Chief Executive Officer and Founder, Cardlytics, Inc., an international technology company

THOMAS D. HYDE
Former Executive Vice President, Legal, Compliance, Ethics and Corporate Secretary, Wal-Mart Stores, Inc.

JAMES A. MITCHELL
Executive Fellow – Leadership, Center for Ethical Business Cultures, a non-profit organization assisting business leaders in creating ethical and profitable cultures

ANN D. MURTLOW
President and Chief Executive Officer, United Way of Central Indiana

SANDRA J. PRICE
Former Senior Vice President Human Resources, Sprint Corporation

JOHN J. SHERMAN
Vice Chairman, Cleveland Indians Baseball Club and Director of Crestwood Equity GP LLC

OFFICERS Great Plains Energy

TERRY BASSHAM
Chairman of the Board, President and Chief Executive Officer

KEVIN E. BRYANT
Senior Vice President – Finance and Strategy and Chief Financial Officer

STEVEN P. BUSSER
Vice President – Risk Management and Controller

CHARLES A. CAISLEY
Vice President – Marketing and Public Affairs

ELLEN E. FAIRCHILD
Vice President, Chief Compliance Officer and Corporate Secretary

HEATHER A. HUMPHREY
Senior Vice President – Corporate Services and General Counsel

LORI A. WRIGHT
Vice President – Corporate Planning, Investor Relations and Treasurer

OFFICERS KCP&L

TERRY BASSHAM
Chairman of the Board, President and Chief Executive Officer

DUANE D. ANSTAETT
Vice President – Generation

KEVIN E. BRYANT
Senior Vice President – Finance and Strategy and Chief Financial Officer

STEVEN P. BUSSER
Vice President – Risk Management and Controller

CHARLES A. CAISLEY
Vice President – Marketing and Public Affairs

ELLEN E. FAIRCHILD
Vice President, Chief Compliance Officer and Corporate Secretary

SCOTT H. HEIDTBRINK
Executive Vice President and Chief Operating Officer

HEATHER A. HUMPHREY
Senior Vice President – Corporate Services and General Counsel

DARRIN R. IVES
Vice President – Regulatory Affairs

MARIA R. JENKS
Vice President – Supply Chain

CHARLES L. KING
Vice President and Chief Information Officer

KEVIN T. NOBLET
Vice President – Delivery

LORI A. WRIGHT
Vice President – Corporate Planning, Investor Relations and Treasurer

SHAREHOLDER INFORMATION

GREAT PLAINS ENERGY FORM 10-K
Great Plains Energy's 2016 annual report on Form 10-K filed with the Securities and Exchange Commission can be found at www.greatplainsenergy.com. The 10-K is available at no charge upon written request to:

Corporate Secretary
Great Plains Energy Incorporated
P.O. Box 418679
Kansas City, MO 64141-9679

MARKET INFORMATION
Great Plains Energy common stock is traded on the New York Stock Exchange under the ticker symbol "GXP." We had 14,886 shareholders of record as of February 21, 2017.

INTERNET SITE
We have a website at www.greatplainsenergy.com. Information available includes our SEC filings, news releases, stock quotes, customer account information, community and environmental efforts and information of general interest to investors and customers.

Also located on the website are our Code of Ethical Business Conduct, Corporate Governance Guidelines and the charters of the Audit Committee, Governance Committee and Compensation and Development Committee of the Board of Directors, which are available at no charge upon written request to the Corporate Secretary.

COMMON STOCK DIVIDEND

QUARTER	2016	2015
First	$0.2625	$0.245
Second	0.2625	0.245
Third	0.2625	0.245
Fourth	0.2750	0.2625

TWO-YEAR COMMON STOCK HISTORY

	2016		2015	
QUARTER	HIGH	LOW	HIGH	LOW
First	$32.26	$26.34	$30.06	$25.80
Second	32.68	28.35	27.52	24.16
Third	31.22	26.53	27.35	24.21
Fourth	28.60	26.20	28.02	25.74

ANNUAL MEETING OF SHAREHOLDERS
Great Plains Energy's annual meeting of shareholders will be held at 10:00 a.m., May 2, 2017, at Great Plains Energy, One Kansas City Place, 1200 Main Street, Kansas City, MO 64105.

REGISTERED SHAREHOLDER INQUIRIES
For account information or assistance, including change of address, stock transfers, dividend payments, duplicate accounts or to report a lost certificate, please contact Investor Relations at 800-245-5275.

FINANCIAL COMMUNITY INQUIRIES
Securities analysts and investment professionals seeking information about Great Plains Energy may contact Investor Relations at 816-556-2312.

TRANSFER AGENT AND STOCK REGISTRANT
Computershare Trust Company, N.A. Investor Services
P. O. Box 30170
College Station, TX 77842-3170
Tel: 866-239-8177

ABOUT THE COMPANIES

Headquartered in Kansas City, Mo., Great Plains Energy Incorporated (NYSE: GXP) is the holding company of Kansas City Power & Light Company (KCP&L) and KCP&L Greater Missouri Operations Company (GMO), two of the leading regulated providers of electricity in the Midwest. KCP&L and GMO use KCP&L as a brand name. More information about the companies is available on the internet at: www.greatplainsenergy.com or www.kcpl.com.

NYSE: GXP

GREAT PLAINS ENERGY

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	**Exact name of registrant as specified in its charter, state of incorporation, address of principal executive offices and telephone number**	**I.R.S. Employer Identification Number**
001-32206	**GREAT PLAINS ENERGY INCORPORATED** (A Missouri Corporation) 1200 Main Street Kansas City, Missouri 64105 (816) 556-2200	43-1916803
000-51873	**KANSAS CITY POWER & LIGHT COMPANY** (A Missouri Corporation) 1200 Main Street Kansas City, Missouri 64105 (816) 556-2200	44-0308720

Each of the following classes or series of securities registered pursuant to Section 12(b) of the Act is registered on the New York Stock Exchange:

Registrant	**Title of each class**
Great Plains Energy Incorporated	Common Stock, without par value

Securities registered pursuant to Section 12(g) of the Act: Kansas City Power & Light Company Common Stock without par value.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Great Plains Energy Incorporated	Yes	X	No	_	Kansas City Power & Light Company	Yes	_	No	X

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Great Plains Energy Incorporated	Yes	_	No	X	Kansas City Power & Light Company	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.

Great Plains Energy Incorporated	Yes	X	No	_	Kansas City Power & Light Company	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 (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Great Plains Energy Incorporated	Yes	X	No	_	Kansas City Power & Light Company	Yes	X	No	_

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to the Form 10-K.

Great Plains Energy Incorporated	X	Kansas City Power & Light Company	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 emerging growth company. See the definitions of “large accelerated filer,” “accelerated filer,” “smaller reporting company,” and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Great Plains Energy Incorporated	Large accelerated filer	X	Accelerated filer	_
	Non-accelerated filer	_	Smaller reporting company	_
			Emerging growth company	_
Kansas City Power & Light Company	Large accelerated filer	_	Accelerated filer	_
	Non-accelerated filer	X	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 Exchange Act.

Great Plains Energy Incorporated	Yes	_	No	_	Kansas City Power & Light Company	Yes	_	No	_

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Great Plains Energy Incorporated	Yes	_	No	X	Kansas City Power & Light Company	Yes	_	No	X

The aggregate market value of the voting and non-voting common equity held by non-affiliates of Great Plains Energy Incorporated (based on the closing price of its common stock on the New York Stock Exchange on June 30, 2017) was approximately $6,311,042,442. All of the common equity of Kansas City Power & Light Company is held by Great Plains Energy Incorporated, an affiliate of Kansas City Power & Light Company.

On February 16, 2018, Great Plains Energy Incorporated had 215,665,193 shares of common stock outstanding.

On February 16, 2018, Kansas City Power & Light Company had one share of common stock outstanding and held by Great Plains Energy Incorporated.

Kansas City Power & Light Company meets the conditions set forth in General Instruction (I)(1)(a) and (b) of Form 10-K and is therefore filing this Form 10-K with the reduced disclosure format.

Documents Incorporated by Reference

Portions of the 2018 annual meeting proxy statement of Great Plains Energy Incorporated to be filed with the Securities and Exchange Commission are incorporated by reference in Part III of this report.

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This combined annual report on Form 10-K is being filed by Great Plains Energy Incorporated (Great Plains Energy) and Kansas City Power & Light Company (KCP&L). KCP&L is a wholly owned subsidiary of Great Plains Energy and represents a significant portion of its assets, liabilities, revenues, expenses and operations. Thus, all information contained in this report relates to, and where required is filed by, Great Plains Energy. Information that is specifically identified in this report as relating solely to Great Plains Energy, such as its financial statements and all information relating to Great Plains Energy's other operations, businesses and subsidiaries, including KCP&L Greater Missouri Operations Company (GMO), does not relate to, and is not filed by, KCP&L. KCP&L makes no representation as to that information. Neither Great Plains Energy nor its other subsidiaries have any obligation in respect of KCP&L's debt securities and holders of such securities should not consider Great Plains Energy's or its other subsidiaries' financial resources or results of operations in making a decision with respect to KCP&L's debt securities. Similarly, KCP&L has no obligation in respect of securities of Great Plains Energy or its other subsidiaries.

CAUTIONARY STATEMENTS REGARDING CERTAIN FORWARD-LOOKING INFORMATION

Statements made in this report that are not based on historical facts are forward-looking, may involve risks and uncertainties, and are intended to be as of the date when made. Forward-looking statements include, but are not limited to, statements relating to the anticipated merger transaction of Great Plains Energy and Westar Energy, Inc. (Westar), including those that relate to the expected financial and operational benefits of the merger to the companies and their shareholders (including cost savings, operational efficiencies and the impact of the anticipated merger on earnings per share), the expected timing of closing, the outcome of regulatory proceedings, cost estimates of capital projects, dividend growth, share repurchases, balance sheet and credit ratings, rebates to customers, employee issues and other matters affecting future operations. In connection with the safe harbor provisions of the Private Securities Litigation Reform Act of 1995, Great Plains Energy and KCP&L are providing a number of important factors that could cause actual results to differ materially from the provided forward-looking information. These important factors include: future economic conditions in regional, national and international markets and their effects on sales, prices and costs; prices and availability of electricity in regional and national wholesale markets; market perception of the energy industry, Great Plains Energy, KCP&L and Westar; changes in business strategy, operations or development plans; the outcome of contract negotiations for goods and services; effects of current or proposed state and federal legislative and regulatory actions or developments, including, but not limited to, deregulation, re-regulation and restructuring of the electric utility industry; decisions of regulators regarding rates that the Companies can charge for electricity; adverse changes in applicable laws, regulations, rules, principles or practices governing tax, accounting and environmental matters including, but not limited to, air and water quality; financial market conditions and performance including, but not limited to, changes in interest rates and credit spreads and in availability and cost of capital and the effects on derivatives and hedges, nuclear decommissioning trust and pension plan assets and costs; impairments of long-lived assets or goodwill; credit ratings; inflation rates; effectiveness of risk management policies and procedures and the ability of counterparties to satisfy their contractual commitments; impact of terrorist acts, including, but not limited to, cyber terrorism; ability to carry out marketing and sales plans; weather conditions including, but not limited to, weather-related damage and their effects on sales, prices and costs; cost, availability, quality and deliverability of fuel; the inherent uncertainties in estimating the effects of weather, economic conditions and other factors on customer consumption and financial results; ability to achieve generation goals and the occurrence and duration of planned and unplanned generation outages; delays in the anticipated in-service dates and cost increases of generation, transmission, distribution or other projects; Great Plains Energy's and Westar's ability to successfully manage and integrate their respective transmission joint ventures; the inherent risks associated with the ownership and operation of a nuclear facility including, but not limited to, environmental, health, safety, regulatory and financial risks; workforce risks, including, but not limited to, increased costs of retirement, health care and other benefits; the ability of Great Plains Energy and Westar to obtain the regulatory approvals necessary to complete the anticipated merger or the imposition of adverse conditions or costs in connection with obtaining regulatory approvals; the risk that a condition to the closing of the anticipated merger may not be satisfied or that the anticipated merger may fail to close; the outcome of any legal proceedings, regulatory proceedings or enforcement matters that may be instituted relating to the anticipated merger; the costs incurred to consummate the anticipated merger; the possibility that the expected value creation from the anticipated 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 anticipated merger; disruption from the anticipated merger making it more difficult to maintain relationships with customers, employees, regulators or suppliers; the diversion of management time and attention on the anticipated merger; and other risks and uncertainties.

This list of factors is not all-inclusive because it is not possible to predict all factors. Part I Item 1A Risk Factors included in this report should be carefully read for further understanding of potential risks for each of Great Plains Energy and KCP&L. Other sections of this report and other periodic reports filed by each of Great Plains Energy and KCP&L with the Securities and Exchange Commission (SEC) should also be read for more information regarding risk factors. Each forward-looking statement speaks only as of the date of the particular statement. Great Plains Energy and KCP&L undertake no obligation to publicly update or revise any forward-looking statement, whether as a result of new information, future events or otherwise.

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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
Amended Merger Agreement	Amended and Restated Agreement and Plan of Merger dated as of July 9, 2017 by and among Great Plains Energy, Westar, Monarch Energy Holding, Inc. and King Energy, Inc.
ARO	Asset Retirement Obligation
ASU	Accounting Standards Update
CCRs	Coal combustion residuals
Clean Air Act	Clean Air Act Amendments of 1990
CO_2	Carbon dioxide
Company	Great Plains Energy Incorporated and its consolidated subsidiaries
Companies	Great Plains Energy Incorporated and its consolidated subsidiaries and KCP&L and its consolidated subsidiaries
DOE	Department of Energy
DOJ	Department of Justice
ECA	Energy Cost Adjustment
EIRR	Environmental Improvement Revenue Refunding
Electric Utility	Electric utility segment
EPA	Environmental Protection Agency
EPS	Earnings (loss) per common share
ERISA	Employee Retirement Income Security Act of 1974, as amended
Exchange Act	The Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FERC	The Federal Energy Regulatory Commission
FCC	The Federal Communications Commission
GAAP	Generally Accepted Accounting Principles
GMO	KCP&L Greater Missouri Operations Company, a wholly owned subsidiary of Great Plains Energy
GP Star	GP Star, Inc.
GPETHC	GPE Transmission Holding Company LLC, a wholly owned subsidiary of Great Plains Energy
Great Plains Energy	Great Plains Energy Incorporated and its consolidated subsidiaries
Great Plains Energy Board	Great Plains Energy Board of Directors
HSR	Hart-Scott-Rodino
Holdco	Monarch Energy Holding, Inc., a Missouri corporation
KCC	The State Corporation Commission of the State of Kansas
KCP&L	Kansas City Power & Light Company, a wholly owned subsidiary of Great Plains Energy, and its consolidated subsidiaries
KCP&L Receivables Company	Kansas City Power & Light Receivables Company, a wholly owned subsidiary of KCP&L
kWh	Kilowatt hour
MEEIA	Missouri Energy Efficiency Investment Act
Merger Sub	King Energy, Inc., a Kansas corporation and wholly owned subsidiary of Holdco
MGP	Manufactured gas plant
MPS Merchant	MPS Merchant Services, Inc., a wholly owned subsidiary of GMO

Abbreviation or Acronym	Definition
MPSC	Public Service Commission of the State of Missouri
MW	Megawatt
MWh	Megawatt hour
NAV	Net asset value
NERC	North American Electric Reliability Corporation
NOL	Net operating loss
NRC	Nuclear Regulatory Commission
OMERS	OCM Credit Portfolio LP
Original Merger Agreement	Agreement and Plan of Merger dated as of May 29, 2016, by and among Great Plains Energy, Westar and GP Star, Inc.
RTO	Regional Transmission Organization
SEC	Securities and Exchange Commission
Series A Preferred Stock	7.25% Mandatory Convertible Preferred Stock, Series A
Series B Preferred Stock	7.00% Series B Mandatory Convertible Preferred Stock
SPP	Southwest Power Pool, Inc.
Transource	Transource Energy, LLC and its subsidiaries, 13.5% owned by GPETHC
WCNOC	Wolf Creek Nuclear Operating Corporation
Westar	Westar Energy, Inc.
Westar Board	Westar Board of Directors
Wolf Creek	Wolf Creek Generating Station

PART I

ITEM 1. BUSINESS

General

Great Plains Energy Incorporated and Kansas City Power & Light Company are separate registrants filing this combined annual report on Form 10-K. The terms "Great Plains Energy," "Company," "KCP&L" and "Companies" are used throughout this report. "Great Plains Energy" and the "Company" refer to Great Plains Energy Incorporated and its consolidated subsidiaries, unless otherwise indicated. "KCP&L" refers to Kansas City Power & Light Company and its consolidated subsidiaries. "Companies" refers to Great Plains Energy Incorporated and its consolidated subsidiaries and KCP&L and its consolidated subsidiaries.

Information in other Items of this report as to which reference is made in this Item 1 is hereby incorporated by reference in this Item 1. The use of terms such as "see" or "refer to" shall be deemed to incorporate into this Item 1 the information to which such reference is made.

GREAT PLAINS ENERGY INCORPORATED

Great Plains Energy, a Missouri corporation incorporated in 2001 and headquartered in Kansas City, Missouri, is a public utility holding company and does not own or operate any significant assets other than the stock of its subsidiaries and cash and cash equivalents. Great Plains Energy's wholly owned direct subsidiaries with significant operations are as follows:

- KCP&L is an integrated, regulated electric utility that provides electricity to customers primarily in the states of Missouri and Kansas. KCP&L has one active wholly owned subsidiary, Kansas City Power & Light Receivables Company (KCP&L Receivables Company).
- GMO is an integrated, regulated electric utility that provides electricity to customers in the state of Missouri. GMO also provides regulated steam service to certain customers in the St. Joseph, Missouri area. GMO has two active wholly owned subsidiaries, GMO Receivables Company and MPS Merchant Services, Inc. (MPS Merchant). MPS Merchant has certain long-term natural gas contracts remaining from its former non-regulated trading operations.

Great Plains Energy also wholly owns GPE Transmission Holding Company, LLC (GPETHC). GPETHC owns 13.5% of Transource Energy, LLC (Transource) with the remaining 86.5% owned by AEP Transmission Holding Company, LLC (AEPTHC), a subsidiary of American Electric Power Company, Inc. GPETHC accounts for its investment in Transource under the equity method. Transource is focused on the development of competitive electric transmission projects.

Great Plains Energy's sole reportable business segment is the electric utility segment (Electric Utility). For information regarding the revenues, income and assets attributable to Electric Utility, see Note 22 to the consolidated financial statements. Comparative financial information and discussion regarding Electric Utility can be found in Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A).

Electric Utility consists of KCP&L, a regulated utility, GMO's regulated utility operations and GMO Receivables Company. Electric Utility serves approximately 867,100 customers located in western Missouri and eastern Kansas. Customers include approximately 764,200 residences, 100,400 commercial firms and 2,500 industrials, municipalities and other electric utilities. Electric Utility's retail revenues averaged approximately 93% of its total operating revenues over the last three years. Wholesale firm power, bulk power sales and miscellaneous electric revenues accounted for the remainder of Electric Utility's revenues. Electric Utility is significantly impacted by seasonality with approximately one-third of its retail revenues recorded in the third quarter. Electric Utility's total electric revenues were 100% of Great Plains Energy's revenues over the last three years. Electric Utility's net income accounted for approximately (242)% of Great Plains Energy's net loss in 2017 and 101% and 105% of Great Plains Energy's net income in 2016 and 2015, respectively.

Anticipated Merger with Westar Energy, Inc.

In May 2016, Great Plains Energy and Westar entered into an Agreement and Plan of Merger dated as of May 29, 2016, by and among Great Plains Energy, Westar and GP Star, Inc. (GP Star) (Original Merger Agreement) in which Great Plains Energy would have acquired Westar for a combination of cash and shares of Great Plains Energy common stock. In April 2017, The State Corporation Commission of the State of Kansas (KCC) issued an order denying Great Plains Energy's, KCP&L's and Westar's joint application for the approval of the acquisition citing concerns with the purchase price, Great Plains Energy's capital structure, quantifiable and demonstrable customer benefits and staffing levels in Westar's service territory, among other items.

In July 2017, Great Plains Energy entered into an Amended and Restated Agreement and Plan of Merger dated as of July 9, 2017 by and among Great Plains Energy, Westar, Monarch Energy Holding, Inc., a Missouri corporation (Holdco), and King Energy, Inc., a Kansas corporation and wholly owned subsidiary of Holdco (Merger Sub) (Amended Merger Agreement). Pursuant to the Amended Merger Agreement, subject to the satisfaction or waiver of certain conditions, Great Plains Energy will merge with and into Holdco, with Holdco surviving such merger, and Merger Sub will merge with and into Westar, with Westar surviving such merger. Pursuant to the Amended Merger Agreement, at closing each outstanding share of Great Plains Energy's and Westar's common stock will be converted into the right to receive 0.5981 and 1.0, respectively, of validly issued, fully paid and nonassessable shares of common stock, no par value, of Holdco. Following the mergers, Holdco, with a new name that has yet to be established, will be the parent of Great Plains Energy's direct subsidiaries, including KCP&L, and Westar.

The anticipated merger with Westar has been structured as a merger of equals in a tax-free exchange of shares that involves no premium paid or received with respect to either Great Plains Energy or Westar. Following the completion of the anticipated merger, Westar shareholders will own approximately 52.5 percent and Great Plains Energy shareholders will own approximately 47.5 percent of the combined company. See Note 2 to the consolidated financial statements for additional information concerning the anticipated merger with Westar.

Regulation

KCP&L and GMO are regulated by the Public Service Commission of the State of Missouri (MPSC) and KCP&L is also regulated by KCC with respect to retail rates, certain accounting matters, standards of service and, in certain cases, the issuance of securities, certification of facilities and service territories. KCP&L and GMO are also subject to regulation by The Federal Energy Regulatory Commission (FERC) with respect to transmission, wholesale sales and rates, and other matters. KCP&L has a 47% ownership interest in Wolf Creek Generating Station (Wolf Creek), which is subject to regulation by the Nuclear Regulatory Commission (NRC) with respect to licensing, operations and safety-related requirements.

The table below summarizes the rate orders in effect for KCP&L's and GMO's retail rate jurisdictions.

	Regulator	Allowed Return on Equity	Rate-Making Equity Ratio	Rate Base (in billions)	Effective Date
KCP&L Missouri	MPSC	9.5%	49.2%	$2.5	June 2017
KCP&L Kansas	KCC	9.3%	50.5%	$2.1	October 2015
GMO	MPSC	9.5% - 9.75%[(a)]	(a)	(a)	February 2017

[(a)] GMO's current rate order reflects a global settlement with an implied return on equity range of 9.5% - 9.75% and does not contain an agreed upon rate-making equity ratio or rate base.

Missouri and Kansas jurisdictional retail revenues averaged approximately 70% and 30%, respectively, of Electric Utility's total retail revenues over the last three years.

See Item 7 MD&A, Critical Accounting Policies section, and Note 6 to the consolidated financial statements for additional information concerning regulatory matters.

Competition
Missouri and Kansas continue on the fully integrated and regulated retail utility model. As a result, KCP&L and GMO do not compete with others to supply and deliver electricity in its franchised service territory, although other sources of energy can provide alternatives to retail electric utility customers. If Missouri or Kansas were to pass and implement legislation authorizing or mandating retail choice, Electric Utility may no longer be able to apply regulated utility accounting principles to deregulated portions of its operations and may be required to write off certain regulatory assets and liabilities.

Electric Utility competes in the wholesale market to sell power in circumstances when the power it generates is not required for customers in its service territory. This competition primarily occurs within the Southwest Power Pool, Inc. (SPP) Integrated Marketplace, in which KCP&L and GMO are participants. Similar to other Regional Transmission Organization (RTO) or Independent System Operator (ISO) markets currently operating, this marketplace determines which generating units among market participants should run, within the operating constraints of a unit, at any given time for maximum regional cost-effectiveness.

In this regard, Electric Utility competes with other regional power suppliers, principally other utilities within the SPP Integrated Marketplace, on the basis of availability and price. Electric Utility's wholesale revenues averaged approximately 5% of its total revenues over the last three years.

Power Supply
Electric Utility has approximately 6,500 MWs of total owned generating capacity and also purchases power to meet its customers' needs, to satisfy firm power commitments or to meet renewable energy standards. Electric Utility's purchased power from others, as a percentage of total MWhs generated and purchased, averaged approximately 26% over the last three years. Management believes Electric Utility will be able to obtain enough power to meet its future demands due to the coordination of planning and operations in the SPP region and existing power purchase agreements; however, price and availability of power purchases may be impacted during periods of high demand.

Electric Utility's total capacity by fuel type, including both owned generating capacity and power purchase agreements, is detailed in the table below.

Fuel Type	Estimated 2018 MW Capacity	Percent of Total Capacity
Coal	3,433	44 %
Nuclear	552	7
Natural gas and oil	2,342	30
Wind [(a)]	1,389	18
Solar, landfill gas and hydroelectric [(b)]	65	1
Total capacity	7,781	100 %

(a) MWs are based on nameplate capacity of the wind facility. Includes owned generating capacity of 149 MWs and long-term power purchase agreements of approximately 1,240 MWs of wind generation which expire in 2032 through 2037.
(b) Includes a long-term power purchase agreement for approximately 60 MWs of hydroelectric generation which expires in 2023.

Electric Utility's projected peak summer demand for 2018 is approximately 5,200 MWs. Electric Utility expects to meet its projected capacity requirements for the foreseeable future with its existing generation assets and power and capacity purchases.

KCP&L and GMO are members of the SPP. The SPP is a FERC-approved RTO with the responsibility to ensure reliable power supply, adequate transmission infrastructure and ensure competitive wholesale electricity prices in the region. As SPP members, KCP&L and GMO are required to maintain a minimum reserve margin of 12%. This net positive supply of capacity is maintained through generation asset ownership, capacity agreements, power purchase agreements and peak demand reduction programs. The reserve margin is designed to support reliability of the region's electric supply.

Fuel

The principal fuel sources for Electric Utility's owned generation are coal and nuclear fuel. It is expected, with normal weather, that approximately 98% of 2018 net MWhs generated will come from these sources with the remainder provided by wind, natural gas and oil. The actual 2017 and estimated 2018 fuel mix and delivered cost in cents per net kilowatt hour (kWh) generated are outlined in the following table.

	Fuel Mix [a]		Fuel cost in cents per net kWh generated	
Fuel	Estimated 2018	Actual 2017	Estimated 2018	Actual 2017
Coal	77 %	75 %	1.84	1.81
Nuclear	21	23	0.62	0.69
Natural gas and oil	<1	1	7.46	15.19
Wind	2	1	—	—
Total owned generation	100 %	100 %	1.42	1.62

[a] Fuel mix based on percent of net MWhs generated.

Coal

During 2018, Electric Utility's generating units, including jointly owned units, are projected to burn approximately 11 million tons of coal. KCP&L and GMO have entered into coal-purchase contracts with various suppliers in Wyoming's Powder River Basin (PRB), the nation's principal supply region of low-sulfur coal, and with local suppliers. The coal to be provided under these contracts is expected to satisfy approximately 95% of the projected coal requirements for 2018 and approximately 40% for 2019. The remainder of the coal requirements is expected to be fulfilled through additional contracts or spot market purchases.

KCP&L and GMO have also entered into rail transportation contracts with various railroads to transport coal from the PRB to their generating units. The transportation services to be provided under these contracts are expected to satisfy almost all of the projected transportation requirements for 2018. The contract rates adjust for changes in railroad costs.

Nuclear Fuel

KCP&L owns 47% of Wolf Creek Nuclear Operating Corporation (WCNOC), the operating company for Wolf Creek, which is Electric Utility's only nuclear generating unit. Wolf Creek purchases uranium and has it processed for use as fuel in its reactor. This process involves conversion of uranium concentrates to uranium hexafluoride, enrichment of uranium hexafluoride and fabrication of nuclear fuel assemblies. The owners of Wolf Creek have on hand or under contract all of the uranium and conversion services needed to operate Wolf Creek through March 2027. The owners also have under contract all of the uranium enrichment and fabrication required to operate Wolf Creek through March 2027 and September 2025, respectively.

See Note 5 to the consolidated financial statements for additional information regarding nuclear plant.

Environmental Matters

See Note 15 to the consolidated financial statements for information regarding environmental matters.

KANSAS CITY POWER & LIGHT COMPANY

KCP&L, a Missouri corporation incorporated in 1922 and headquartered in Kansas City, Missouri, is an integrated, regulated electric utility that engages in the generation, transmission, distribution and sale of electricity. KCP&L serves approximately 542,500 customers located in western Missouri and eastern Kansas. Customers include approximately 479,300 residences, 61,200 commercial firms, and 2,000 industrials, municipalities and other electric utilities. KCP&L's retail revenues averaged approximately 92% of its total operating revenues over the last three years. Wholesale firm power, bulk power sales and miscellaneous electric revenues accounted for the remainder of KCP&L's revenues. KCP&L is significantly impacted by seasonality with approximately one-third of its retail revenues recorded in the third quarter. Missouri and Kansas jurisdictional retail revenues averaged approximately 57% and 43%, respectively, of total retail revenues over the last three years.

Great Plains Energy and KCP&L Employees

At December 31, 2017, Great Plains Energy and KCP&L had 2,709 employees, including 1,664 represented by three local unions of the International Brotherhood of Electrical Workers (IBEW). KCP&L has labor agreements with Local 1613, representing clerical employees (expires March 31, 2018), with Local 1464, representing transmission and distribution workers (expires February 28, 2018), and with Local 412, representing power plant workers (expires February 28, 2021).

Executive Officers

All of the individuals in the following table have been officers or employees in the responsible positions with the Company noted below for the past five years unless otherwise indicated in the footnotes. The executive officers were reappointed to the indicated positions by the respective boards of directors, effective January 1, 2018, to hold such positions until their resignation, removal or the appointment of their successors. There are no family relationships between any of the executive officers, nor any arrangement or understanding between any executive officer and any other person involved in officer selection. Each executive officer holds the same position with GMO as he or she does with KCP&L.

Name	Age	Current Position(s)	Year First Assumed an Officer Position
Terry Bassham [a]	57	Chairman of the Board, President and Chief Executive Officer - Great Plains Energy and KCP&L	2005
Kevin E. Bryant [b]	42	Senior Vice President - Finance and Strategy and Chief Financial Officer - Great Plains Energy and KCP&L	2006
Steven P. Busser [c]	49	Vice President - Risk Management and Controller - Great Plains Energy and KCP&L	2014
Charles A. Caisley [d]	45	Vice President - Marketing and Public Affairs - Great Plains Energy and KCP&L	2011
Ellen E. Fairchild [e]	56	Vice President, Chief Compliance Officer and Corporate Secretary - Great Plains Energy and KCP&L	2010
Heather A. Humphrey [f]	47	Senior Vice President - Corporate Services and General Counsel - Great Plains Energy and KCP&L	2010
Darrin R. Ives [g]	48	Vice President - Regulatory Affairs - KCP&L	2013
Lori A. Wright [h]	55	Vice President - Corporate Planning, Investor Relations and Treasurer - Great Plains Energy and KCP&L	2002

(a) Mr. Bassham was appointed Chairman of the Board in May 2013 and has served as Chief Executive Officer of Great Plains Energy, KCP&L and GMO since 2012. He has served as President of each company since 2011. He previously served as President and Chief Operating Officer of Great Plains Energy, KCP&L and GMO (2011-2012) and as Executive Vice President - Utility Operations of KCP&L and GMO (2010-2011). He was Executive Vice President - Finance and Strategic Development and Chief Financial Officer of Great Plains Energy (2005-2010) and of KCP&L and GMO (2009-2010).

(b) Mr. Bryant was appointed Senior Vice President - Finance and Strategy and Chief Financial Officer of Great Plains Energy, KCP&L and GMO in 2015. He previously served as Vice President - Strategic Planning of Great Plains Energy, KCP&L and GMO (2014). He served as Vice President - Investor Relations and Strategic Planning and Treasurer of Great Plains Energy, KCP&L and GMO (2013). He served as Vice President - Investor Relations and Treasurer of Great Plains Energy, KCP&L and GMO (2011-2013). He was Vice President - Strategy and Risk Management of KCP&L and GMO (2011) and Vice President - Energy Solutions (2006-2011) of KCP&L and GMO.

(c) Mr. Busser was appointed Vice President - Risk Management and Controller of Great Plains Energy, KCP&L and GMO in 2016. He previously served as Vice President - Business Planning and Controller of Great Plains Energy, KCP&L and GMO (2014-2016). He served as Vice President - Treasurer of El Paso Electric Company (2011-2014). Prior to that, he served as Vice President - Treasurer and Chief Risk Officer (2006-2011) and Vice President - Regulatory Affairs and Treasurer (2004-2006) of El Paso Electric Company.

(d) Mr. Caisley was appointed Vice President - Marketing and Public Affairs of Great Plains Energy, KCP&L and GMO in 2011. He was Senior Director of Public Affairs (2008-2011) and Director of Governmental Affairs of KCP&L (2007-2008).

(e) Ms. Fairchild was appointed Vice President, Chief Compliance Officer and Corporate Secretary of Great Plains Energy, KCP&L and GMO in 2010. She was Senior Director of Investor Relations and Assistant Secretary (2010) and Director of Investor Relations (2008-2010) of Great Plains Energy, KCP&L and GMO.

(f) Ms. Humphrey was appointed Senior Vice President - Corporate Services and General Counsel of Great Plains Energy, KCP&L and GMO in 2016. She previously served as General Counsel (2010-2016) and Senior Vice President - Human Resources of Great Plains Energy, KCP&L and GMO (2012-2016). She served as Vice President - Human Resources of Great Plains Energy, KCP&L and GMO (2010-2012). She was Senior Director of Human Resources and Interim General Counsel of Great Plains Energy, KCP&L and GMO (2010) and Managing Attorney of KCP&L (2007-2010).

(g) Mr. Ives was appointed Vice President - Regulatory Affairs of KCP&L and GMO in 2013. He previously served as Senior Director - Regulatory Affairs of KCP&L and GMO (2011-2013). He was Assistant Controller of Great Plains Energy, KCP&L and GMO (2008 - 2011).

(h) Ms. Wright was appointed Vice President - Corporate Planning, Investor Relations and Treasurer of Great Plains Energy, KCP&L and GMO in 2016. She previously served as Vice President - Investor Relations and Treasurer of Great Plains Energy, KCP&L and GMO (2014-2016). She served as Vice President - Business Planning and Controller of Great Plains Energy, KCP&L and GMO (2009-2014). She was Controller of Great Plains Energy and KCP&L (2002-2008) and GMO (2008).

Available Information

Great Plains Energy's website is www.greatplainsenergy.com and KCP&L's website is www.kcpl.com. Information contained on these websites is not incorporated herein. The Companies make available, free of charge, on or through their websites, their annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended (Exchange Act), as soon as reasonably practicable after the companies electronically file such material with, or furnish it to, the SEC. In addition, the Companies make available on or through their websites all other reports, notifications and certifications filed electronically with the SEC.

The public may read and copy any materials that the Companies file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. For information on the operation of the Public Reference Room, please call the SEC at 1-800-SEC-0330. The SEC also maintains an Internet site at http://www.sec.gov that contains reports, proxy statements and other information regarding the Companies.

Investors should note that the Companies announce material financial information in SEC filings, press releases and public conference calls. Based on guidance from the SEC, the Companies may use the Investor Relations section of Great Plains Energy's website (www.greatplainsenergy.com) to communicate with investors about Great Plains Energy and KCP&L. It is possible that the financial and other information posted there could be deemed to be material information. The information on Great Plains Energy's website is not part of this document.

ITEM 1A. RISK FACTORS

Risks Relating to the Anticipated Merger with Westar:

The value of the shares of Holdco common stock that Great Plains Energy's shareholders receive upon the consummation of the anticipated merger may be less than the value of the shares of Great Plains Energy

common stock as of the date of the Amended Merger Agreement, the date of this report or the date of the shareholders' meeting.
The exchange ratio for Great Plains Energy in the Amended Merger Agreement is fixed and will not be adjusted in the event of any change in the stock price of Great Plains Energy prior to the anticipated merger. A significant amount of time will have elapsed between the dates when the shareholders of Great Plains Energy voted to approve the Amended Merger Agreement at the shareholders' meeting on November 21, 2017, and the date when the anticipated merger is completed. The absolute and relative price of shares of Great Plains Energy common stock may vary significantly between the date of the meetings, the date of this report and the date of the completion of the anticipated merger. These variations may be caused by, among other things, changes in the businesses, operations, results or prospects of Great Plains Energy and Westar, market expectations of the likelihood that the anticipated merger will be completed and the timing of completion, the prospects of post-merger operations, general market and economic conditions and other factors. In addition, it is impossible to predict accurately the market price of the Holdco common stock to be received by Great Plains Energy shareholders after the completion of the anticipated merger. Accordingly, the price of Great Plains Energy common stock on the date of this report and on the date of the meetings may not be indicative of the price immediately prior to completion of the anticipated merger and the price of Holdco common stock after the anticipated merger is completed.

The ability of Great Plains Energy and Westar to complete the anticipated merger is subject to various closing conditions, including the receipt of consents and approvals from governmental authorities, which may impose conditions that could adversely affect Great Plains Energy or cause the anticipated merger to be abandoned.
To complete the anticipated merger, (1) each of Great Plains Energy and Westar must also make certain filings with and obtain certain consents and approvals from various governmental and regulatory authorities, (2) the listing on the New York Stock Exchange of the shares of Holdco common stock to be issued to Great Plains Energy and Westar shareholders in the anticipated merger must be approved, (3) there cannot be any material adverse effect with respect to Great Plains Energy, Westar and their respective subsidiaries, (4) there cannot be any laws or judgments, whether preliminary, temporary or permanent, which may prevent, make illegal or prohibit the completion of the anticipated merger, (5) subject to certain materiality exceptions, the representations and warranties made by Great Plains Energy and Westar, respectively, must be accurate and the parties must comply with their respective obligations under the Amended Merger Agreement, (6) Great Plains Energy and Westar must receive certain tax opinions, (7) there cannot be any shares of Great Plains Energy preference stock outstanding and (8) Great Plains Energy must have not less than $1.25 billion in cash or cash equivalents on its balance sheet. If the foregoing conditions are not satisfied or waived, one or both of Great Plains Energy and Westar would not be required to complete the merger.

Great Plains Energy and Westar have not yet obtained the regulatory consents and approvals required to complete the anticipated merger. Governmental or regulatory agencies could seek to block or challenge the anticipated merger or could impose restrictions they deem necessary or desirable in the public interest as a condition to approving the anticipated merger. Great Plains Energy and Westar will be unable to complete the anticipated merger until the consents and approvals have been received from KCC, the MPSC, the NRC, FERC and The Federal Communication Commission (FCC) (collectively referred to as the “required governmental approvals”). Regulatory authorities may impose certain requirements or obligations as conditions for their approval. The Amended Merger Agreement may require Great Plains Energy and/or Westar to accept conditions from these regulators that could adversely impact the combined company. If the required governmental approvals are not received, or they are not received on terms that satisfy the conditions set forth in the Amended Merger Agreement, then neither Great Plains Energy nor Westar will be obligated to complete the anticipated merger.

In December 2017, the Federal Trade Commission (FTC) granted Great Plains Energy's request for early termination of the waiting period under the Hart-Scott-Rodino (HSR) Act.

Even after the statutory waiting period under the antitrust laws and even after completion of the anticipated merger, governmental authorities could seek to block or challenge the anticipated merger as they deem necessary or desirable in the public interest. In addition, in some jurisdictions, a private party could initiate an action under the antitrust laws challenging or seeking to enjoin the anticipated merger, before or after it is completed. Great Plains

Energy or Westar may not prevail and may incur significant costs in defending or settling any action under the antitrust laws.

The shareholders' meetings at which the Great Plains Energy shareholders and the Westar shareholders voted to approve the transactions contemplated by the Amended Merger Agreement took place before all such approvals have been obtained and before the terms of any conditions to obtain such approvals that may be imposed are known. As a result, Great Plains Energy and Westar may make decisions after the meetings to waive a condition or approve certain actions required to obtain necessary approvals without seeking further shareholder approval. Such actions could have an adverse effect on the combined company.

In addition, the Amended Merger Agreement contains other customary closing conditions, which may not be satisfied or waived.

If Great Plains Energy and Westar are unable to complete the anticipated merger, Great Plains Energy would be subject to a number of risks, including the following:

- Great Plains Energy would not realize the anticipated benefits of the anticipated merger, including, among other things, increased operating efficiencies and future cost savings;
- the attention of management of Great Plains Energy may have been diverted to the anticipated merger rather than to its own operations and the pursuit of other opportunities that could have been beneficial;
- the potential loss of key personnel during the pendency of the anticipated merger as employees may experience uncertainty about their future roles with the combined company;
- Great Plains Energy will have been subject to certain restrictions on the conduct of their businesses, which may prevent Great Plains Energy from making certain acquisitions or dispositions or pursuing certain business opportunities while the anticipated merger is pending; and
- the trading price of Great Plains Energy common stock may decline to the extent that the current market price reflects a market assumption that the anticipated merger will be completed.

Great Plains Energy can provide no assurance that the various closing conditions will be satisfied and that the required governmental approvals and other approvals will be obtained, or that any required conditions will not materially adversely affect the combined company following the anticipated merger. In addition, Great Plains Energy can provide no assurance that these conditions will not result in the abandonment or delay of the anticipated merger. The occurrence of any of these events individually or in combination could have a material adverse effect on the companies' results of operations and the trading price of Great Plains Energy common stock.

The Amended Merger Agreement contains provisions that limit Great Plains Energy's ability to pursue alternatives to the anticipated merger, could discourage a potential acquirer of Great Plains Energy from making a favorable alternative transaction proposal and, in certain circumstances, could require Great Plains Energy to pay a termination fee to the other party.

Under the Amended Merger Agreement, Great Plains Energy and Westar each are restricted from entering into alternative transactions. Unless and until the Amended Merger Agreement is terminated, subject to specified exceptions, each party is restricted from soliciting, initiating or knowingly encouraging, inducing or facilitating, or participating in any discussions or negotiations with any person regarding, or cooperating in any way with any person with respect to, any alternative proposal or any inquiry or proposal that would reasonably be expected to lead to an alternative proposal. Great Plains Energy and Westar each may terminate the Amended Merger Agreement and enter into an agreement with respect to a superior proposal only if specified conditions have been satisfied, including compliance with the provisions of the Amended Merger Agreement restricting solicitation of alternative proposals and requiring payment of a termination fee in certain circumstances. These provisions could discourage a third party that may have an interest in acquiring all or a significant part of Great Plains Energy from considering or proposing that acquisition, even if such third party were prepared to pay consideration with a higher market value than the market value proposed to be received or realized in the anticipated merger, or might result in a potential acquirer proposing to pay a lower price than it would otherwise have proposed to pay because of the added expense of the termination fee that may become payable in certain circumstances. As a result of these restrictions, Great Plains Energy may not be able to enter into an agreement with respect to a more favorable alternative transaction without incurring potentially significant liability to Westar.

The Amended Merger Agreement provides that in connection with the termination of the Amended Merger Agreement under specified circumstances relating to a failure to obtain regulatory approvals, a final and nonappealable order enjoining the consummation of the anticipated merger in connection with regulatory approvals or failure by Great Plains Energy to comply with its obligations under the Amended Merger Agreement to consummate the closing of the anticipated merger once all of the conditions have been satisfied, Great Plains Energy may be required to pay Westar a termination fee of $190 million. In addition, in the event that the Amended Merger Agreement is terminated by Westar under certain circumstances to enter into a definitive acquisition agreement with respect to a superior proposal, Westar may be required to pay Great Plains Energy a termination fee of $190 million. Similarly, in the event that the Amended Merger Agreement is terminated by Great Plains Energy under certain circumstances to enter into a definitive acquisition agreement with respect to a superior proposal, Great Plains Energy may be required to pay Westar a termination fee of $190 million.

Great Plains Energy will be subject to various uncertainties while the anticipated merger is pending that may cause disruption and may make it more difficult to maintain relationships with employees, suppliers, or customers.

Uncertainty about the effect of the anticipated merger on employees, suppliers and customers may have an adverse effect on Great Plains Energy. These uncertainties may impair the ability of Great Plains Energy to attract, retain and motivate key personnel until the anticipated merger is completed and for a period of time thereafter, and could cause customers, suppliers and others that deal with Great Plains Energy to seek to change or terminate existing business relationships with Great Plains Energy or not enter into new relationships or transactions.

Employee retention and recruitment may be particularly challenging prior to the completion of the anticipated merger, as employees and prospective employees may experience uncertainty about their future roles with the combined company. If, despite Great Plains Energy's retention and recruiting efforts, key employees depart or fail to continue employment because of issues relating to the uncertainty and difficulty of integration or a desire not to remain with the combined company, Great Plains Energy's financial results could be adversely affected. Furthermore, the combined company's operational and financial performance following the anticipated merger could be adversely affected if it is unable to retain key employees and skilled workers of Great Plains Energy. The loss of the services of key employees and skilled workers and their experience and knowledge regarding Great Plains Energy's businesses could adversely affect the combined company's future operating results and the successful ongoing operation of its businesses.

Great Plains Energy is subject to contractual restrictions in the Amended Merger Agreement that may hinder its operations pending the anticipated merger.

The Amended Merger Agreement restricts Great Plains Energy, without Westar's consent, from making certain acquisitions and taking other specified actions until the anticipated merger occurs or the Amended Merger Agreement terminates. These restrictions may prevent Great Plains Energy from pursuing otherwise attractive business opportunities and making other changes to its business prior to completion of the anticipated merger or termination of the Amended Merger Agreement.

Failure to complete the anticipated merger, or significant delays in completing the anticipated merger, could negatively affect the trading price of Great Plains Energy common stock and the future business and financial results of Great Plains Energy.

Completion of the anticipated merger is not assured and is subject to risks, including the risks that approval of the anticipated merger by governmental agencies is not obtained or that other closing conditions are not satisfied. If the anticipated merger is not completed, or if there are significant delays in completing the anticipated merger, it could negatively affect the trading price of Great Plains Energy common stock and its future business and financial results, and Great Plains Energy will be subject to several risks, including the following:

- Great Plains Energy may be liable for damages to Westar under the terms and conditions of the Amended Merger Agreement;
- negative reactions from the financial markets, including declines in the price of Great Plains Energy common stock due to the fact that current prices may reflect a market assumption that the anticipated merger will be completed; and
- having to pay certain significant costs relating to the anticipated merger, including, in certain circumstances, a termination fee.

Failure to successfully combine the businesses of Great Plains Energy and Westar in the expected time frame may adversely affect the future results of the combined company, and, consequently, the value of the Holdco common stock that Great Plains Energy shareholders receive as the merger consideration.

The success of the anticipated merger will depend, in part, on the ability of the combined company to realize the anticipated benefits and efficiencies from combining the businesses of Great Plains Energy and Westar. To realize these anticipated benefits, the businesses must be successfully combined. If the combined company is not able to achieve these objectives, or is not able to achieve these objectives on a timely basis, the anticipated benefits of the transactions may not be realized fully or at all. In addition, the actual integration may result in additional and unforeseen expenses, which could reduce the anticipated benefits of the anticipated merger. These integration difficulties could result in a decline in the market value of Holdco common stock and, consequently, result in a decline in the market value of the Holdco common stock that Great Plains Energy shareholders receive as part of the merger consideration and continue to hold following consummation of the anticipated merger.

Great Plains Energy will incur significant transaction and other merger-related costs in connection with the anticipated merger.

Great Plains Energy has incurred and expects to incur additional costs associated with combining the operations of the two companies, as well as transaction fees and other costs related to the anticipated merger. Additional unanticipated costs may also be incurred in the integration of the businesses of Great Plains Energy and Westar. Any net benefit from the anticipated elimination of duplicative costs, as well as the realization of other efficiencies related to the integration of the businesses, may not be achieved in the near term or at all. Transaction costs could have a material adverse impact on the results of Great Plains Energy, and the failure to achieve the anticipated benefits and efficiencies from the merger, or the incurrence of additional expenses, could have a material adverse impact on the results of operations of the combined company and its ability to pay dividends after closing. In turn, the current market value of Great Plains Energy common stock, or the future market value of Holdco common stock that Great Plains Energy shareholders receive as merger consideration, could be adversely impacted.

The market price of Holdco's common stock after the anticipated merger may be affected by factors different from those affecting the shares of Great Plains Energy or Westar currently.

Upon completion of the anticipated merger, the businesses of the combined company will differ from those of Great Plains Energy and Westar prior to the anticipated merger in important respects and, accordingly, the results of operations of the combined company and the market price of Holdco's shares of common stock following the anticipated merger may be affected by factors different from those currently affecting the independent results of operations of Great Plains Energy and Westar.

Each of Westar and Great Plains Energy and their respective subsidiaries has substantial amounts of indebtedness. Consequently, the combined company will have substantial indebtedness following the anticipated merger. As a result, it may be difficult for the combined company to pay or refinance its debts or take other actions, and the combined company may need to divert its cash flow from operations to debt service payments. The combined company's debt service obligations with respect to this indebtedness could have an adverse impact on its earnings and cash flows for as long as the indebtedness is outstanding.

The combined company's indebtedness could also have important consequences to holders of Holdco common stock. For example, it could:

- make it more difficult for the combined company to pay or refinance its debts as they become due during adverse economic and industry conditions because any decrease in revenues could cause the combined company to not have sufficient cash flows from operations to make its scheduled debt payments;

- require a substantial portion of the combined company's cash flows from operations to be used for debt service payments, thereby reducing the availability of its cash flow to fund working capital, capital expenditures, acquisitions, dividend payments and other general corporate purposes;

- result in a downgrade in the rating of the combined company's indebtedness, which could limit its ability to borrow additional funds or increase the interest rates applicable to its indebtedness; or

- require that additional terms, conditions or covenants be placed on Holdco.

Based upon current levels of operations, Holdco expects to be able to generate sufficient cash on a consolidated basis to make all of the principal and interest payments when such payments are due under the combined company's existing credit facilities, indentures and other instruments governing its outstanding indebtedness, but there can be no assurance that the combined company will be able to repay or refinance such borrowings and obligations.

The anticipated benefits of combining the companies may not be realized.
Great Plains Energy entered into the Amended Merger Agreement with the expectation that the anticipated merger would result in various benefits, including, among other things, increased operating efficiencies and future cost savings that cannot be quantified with certainty at this time. Although Great Plains Energy expects to achieve the anticipated benefits of the anticipated merger, achieving them is subject to a number of uncertainties, including:

- whether U.S. federal and state public utility, antitrust and other regulatory authorities whose approval is required to complete the anticipated merger impose conditions on the merger, which may have an adverse effect on the combined company, including its ability to achieve the anticipated benefits of the merger;

- the ability of the two companies to combine certain of their operations or take advantage of expected growth opportunities;

- general market and economic conditions;

- general competitive factors in the marketplace; and

- higher than expected costs required to achieve the anticipated benefits of the merger.

No assurance can be given that these benefits will be achieved or, if achieved, the timing of their achievement. Failure to achieve these anticipated benefits could result in increased costs and decreases in the amount of expected revenues or net income of the combined company.

The anticipated merger may not be accretive to Great Plains Energy's earnings and may cause dilution to Great Plains Energy's earnings per share, which may negatively affect the market price of Holdco common stock that Great Plains Energy's shareholders receive upon the consummation of the anticipated merger.
Great Plains Energy currently anticipates that the anticipated merger will be accretive to Great Plains Energy's forecasted earnings per share on a standalone basis. This expectation is based on preliminary estimates, including with respect to the anticipated timing and amount of common stock repurchases following the closing of the merger, any of which may materially change. Great Plains Energy may encounter additional transaction and integration-related costs than it currently anticipates, may fail to realize all of the benefits anticipated in the merger or may be subject to other factors that affect preliminary estimates or its ability to realize operational efficiencies. Any of these factors could cause a decrease in the combined company's earnings per share or decrease or delay the expected accretive effect of the anticipated merger and contribute to a decrease in the price of Holdco common stock.

The anticipated merger will combine two companies that are currently affected by developments in the electric utility industry, including changes in regulation and increased competition. A failure to adapt to the changing regulatory environment after the anticipated merger could adversely affect the stability of the combined company's earnings and could result in the erosion of its market positions, revenues and profits.
Because Great Plains Energy, Westar and their respective subsidiaries are regulated in the U.S. at the federal level and in several states, the two companies have been and will continue to be affected by legislative and regulatory developments. After the anticipated merger, the combined company and/or its subsidiaries will be subject in the U.S. to extensive federal regulation as well as to state regulation in Missouri and Kansas. Each of these jurisdictions has implemented, is in the process of implementing or possibly will implement changes to the regulatory and legislative framework applicable to the electric utility industry. These changes could have a material adverse effect on the combined company.

The costs and burdens associated with complying with these regulatory jurisdictions may have a material adverse effect on the combined company. Moreover, potential legislative changes, regulatory changes or otherwise may create greater risks to the stability of utility earnings generally. If the combined company is not responsive to these changes, it could suffer erosion in market position, revenues and profits as competitors gain access to the service territories of its utility subsidiaries.

The price of Holdco common stock that Great Plains Energy's shareholders receive upon the consummation of the anticipated merger may experience volatility.
Following the consummation of the anticipated merger, the price of Holdco common stock may be volatile. Some of the factors that could affect the price of Holdco common stock are quarterly increases or decreases in revenue or earnings, changes in revenue or earnings estimates by the investment community, the ability of Holdco to implement its integration strategy and to realize the expected synergies and other benefits from the anticipated merger and speculation in the press or investment community about Holdco's financial condition or results of operations. General market conditions and U.S. economic factors and political events unrelated to the performance of Holdco may also affect its stock price. For these reasons, shareholders should not rely on recent trends in the price of Great Plains Energy common stock to predict the future price of Holdco's common stock or its financial results.

Utility Regulatory Risks:

Complex utility regulation could adversely affect the Companies' results of operations, financial position and cash flows.
The Companies are subject to, or affected by, extensive federal and state utility regulation, including regulation by the MPSC, KCC, FERC, NRC, North American Electric Reliability Corporation (NERC) and SPP. The Companies must address in their business planning and management of operations the effects of existing and proposed laws and regulations and potential changes in the regulatory framework, including initiatives by federal and state legislatures, RTOs, utility regulators and taxing authorities. Failure of the Companies to obtain adequate rates or regulatory approvals in a timely manner, new or changed laws, regulations, standards, interpretations or other legal requirements, deterioration of the Companies' relationship with regulators and increased compliance costs and potential non-compliance consequences may materially affect the Companies' results of operations, financial

position and cash flows. Additionally, regulators may impose burdensome restrictions and conditions on the Companies' transactions and ventures, rendering them less attractive from a financial or operational perspective. Certain of these risks are addressed in greater detail below.

The outcome of retail rate proceedings could have a material impact on the business and is largely outside the Companies' control.
The rates that KCP&L and GMO are allowed to charge their customers significantly influence the Companies' results of operations, financial position and cash flows. These rates are subject to the determination, in large part, of governmental entities outside of the Companies' control, including the MPSC, KCC and FERC.

The utility rate-setting principle generally applicable to KCP&L and GMO is that rates should provide a reasonable opportunity to recover expenses and investments prudently incurred to provide utility service plus a reasonable return on such investments. Various expenses incurred by KCP&L and GMO have been excluded from rates by the MPSC and KCC in past rate cases as not being prudently incurred or not providing utility customer benefit, and there is a risk that certain expenses incurred in the future may not be recovered in rates. Third-parties often intervene in the utilities' rate cases and argue that certain costs have not been prudently incurred or are otherwise not recoverable in rates. The MPSC and KCC also have in the past and may in the future exclude from rates all or a portion of investments in various facilities as not being prudently incurred or not being useful in providing utility service.

As discussed in the "Environmental Risks" and "Financial Risks" sections below, the Companies' capital expenditures are substantial and there is a risk that a portion of the capital costs could be excluded from rates in future rate cases.

The Companies are also exposed to cost-recovery shortfalls due to the inherent "regulatory lag" in the rate-setting process, especially during periods of significant cost inflation or declining retail usage, as KCP&L's and GMO's utility rates are generally based on historical information and are not subject to adjustment between rate cases, other than principally for fuel, purchased power, transmission and property taxes for KCP&L in Kansas; fuel, purchased power, certain transmission costs and demand-side investments for KCP&L in Missouri; and fuel, purchased power, certain transmission costs, demand-side investments and renewable energy (solar rebates) for GMO. These and other factors may result in under-recovery of costs, failure to earn the authorized return on investment, or both.

Failure to timely recover the full investment costs of capital projects, the impact of renewable energy and energy efficiency programs, other utility costs and expenses due to regulatory disallowances, regulatory lag or other factors could lead to lowered credit ratings, reduced access to capital markets, increased financing costs, lower flexibility due to constrained financial resources and increased collateral security requirements, or reductions or delays in planned capital expenditures. In response to competitive, economic, political, legislative, public perception (including, but not limited to, the Companies' environmental reputation) and regulatory pressures, the Companies may be subject to rate moratoriums, rate refunds, limits on rate increases, lower allowed returns on investments or rate reductions, including phase-in plans designed to spread the impact of rate increases over an extended period of time for the benefit of customers.

Regulatory requirements regarding utility operations may increase costs and may expose the Companies to compliance penalties or adverse rate consequences.
The FERC, NERC and SPP have implemented and enforce an extensive set of transmission system reliability, cybersecurity and critical infrastructure protection standards that apply to public utilities, including KCP&L and GMO. The MPSC and KCC have the authority to implement utility operational standards and requirements, such as vegetation management standards, facilities inspection requirements and quality of service standards. In addition, the Companies are also subject to health, safety and other requirements enacted by the Occupational Safety and Health Administration, the Department of Transportation, the Department of Labor and other federal and state agencies. As discussed more fully under "Operational Risks," the NRC extensively regulates nuclear power plants, including Wolf Creek. The costs of existing, new or modified regulations, standards and other requirements could have an adverse effect on the

Companies' results of operations, financial position and cash flows as a result of increased operations or maintenance and capital expenditures for new facilities or to repair or improve existing facilities. In addition, failure to meet quality of service, reliability, cybersecurity, critical infrastructure protection, operational or other standards and requirements could expose the Companies to penalties, additional compliance costs, or adverse rate consequences.

Environmental Risks:

The Companies are subject to current and potential environmental requirements and the incurrence of environmental liabilities, any or all of which may adversely affect their business and financial results.
The Companies are subject to extensive federal, state and local environmental laws, regulations and permit requirements relating to air and water quality, waste management and disposal, natural resources and health and safety. In addition to imposing continuing compliance obligations and remediation costs for historical and pre-existing conditions, these laws, regulations and permits authorize the imposition of substantial penalties for noncompliance, including fines, injunctive relief and other sanctions. There is also a risk that new environmental laws and regulations, new administrative or judicial interpretations of environmental laws and regulations, or the requirements in new or renewed environmental permits could adversely affect the Companies' operations. In addition, there is also a risk of lawsuits brought by third parties alleging violations of environmental commitments or requirements, claiming creation of a public nuisance or other matters, and seeking injunctions or monetary damages or other damages. Certain federal courts have held that state and local governments and private parties have standing to bring climate change tort suits seeking company-specific emission reductions and damages.

Environmental permits are subject to periodic renewal, which may result in more stringent permit conditions and limits. New facilities, or modifications of existing facilities, may require new environmental permits or amendments to existing permits. Delays in the environmental permitting process, public opposition and challenges, denials of permit applications, limits or conditions imposed in permits and the associated uncertainty may materially adversely affect the cost and timing of projects, and thus materially adversely affect the Companies' results of operations, financial position and cash flows.

KCP&L and GMO periodically seek recovery of capital costs and expenses for environmental compliance and remediation through rate increases; however, there can be no assurance that recovery of these costs would be granted. KCP&L and GMO may be subject to material adverse rate treatment in response to competitive, economic, political, legislative or regulatory pressures and/or public perception of the Companies' environmental reputation. The costs of compliance or noncompliance with environmental requirements, remediation costs, adverse outcomes of lawsuits, or failure to timely recover environmental costs could have a material adverse effect on the Companies' results of operations, financial position and cash flows. Certain of these matters are discussed in more detail below. See Note 15 to the consolidated financial statements for additional information regarding certain significant environmental matters and Great Plains Energy's and KCP&L's current estimates of capital expenditures to comply with environmental regulations.

Air and Climate Change
The Companies' current generation capacity is primarily coal-fired, and is estimated to produce about one ton of carbon dioxide (CO_2) per MWh, or approximately 17 million tons and 13 million tons of CO_2 per year for Great Plains Energy and KCP&L, respectively. Management believes it is possible that additional federal or relevant state or local laws or regulations could be enacted to address global climate change. At the international level, the Paris Agreement was adopted in December 2015 by nearly 200 countries and became effective in November 2016. The Paris Agreement does not result in any new, legally binding obligations on the U.S. to meet a particular greenhouse gas emissions target, but establishes a framework for international cooperation on climate change. In June 2017, U.S. President Donald Trump announced the U.S. would withdraw from the Paris Agreement. Under the rules of the Paris Agreement, the earliest any country can withdraw is November 2020. Other international agreements legally binding on the U.S. may be reached in the future. Greenhouse gas legislation has the potential of having significant financial and operational impacts on Great Plains Energy and KCP&L; however, the ultimate financial and operational consequences to Great Plains Energy and KCP&L cannot be determined until such legislation is passed. In

the absence of new Congressional mandates, the EPA is proceeding with regulation of greenhouse gases under the existing Clean Air Act.

In August 2015, the EPA finalized CO_2 emission standards for new, modified and reconstructed affected fossil-fuel-fired electric utility generating units. The standards would not apply to Great Plains Energy's and KCP&L's existing units unless the units were modified or reconstructed in the future. Also in August 2015, the EPA finalized its Clean Power Plan which sets CO_2 emission performance rates for existing affected fossil-fuel-fired electric generating units. Nationwide, by 2030, the EPA projects the Clean Power Plan would achieve CO_2 emission reductions from the power sector of approximately 32% from CO_2 emission levels in 2005.

In February 2016, the U.S. Supreme Court granted a stay of the Clean Power Plan putting the rule on hold pending review in the U.S. Court of Appeals for the District of Columbia Circuit and any subsequent review by the U.S. Supreme Court if such review is sought. In October 2017, the EPA proposed to repeal the Clean Power Plan on the basis that it exceeded the EPA's statutory authority. In December 2017, the EPA issued an advance notice of proposed rulemaking (ANPRM) to solicit comments as the agency considers proposing a future rule to replace the Clean Power Plan. In the ANPRM, the EPA is considering proposing emission guidelines to limit greenhouse gas emissions from existing electric utility generating units. Compliance with the Clean Power Plan or any replacement rule has the potential of having significant financial and operational impacts on Great Plains Energy and KCP&L; however, the ultimate financial and operational consequences to Great Plains Energy and KCP&L cannot be determined until the outcome of the EPA's proposal to repeal the Clean Power Plan and pending litigation is known.

Water

The Clean Water Act and associated regulations enacted by the EPA form a comprehensive program to restore and preserve water quality. All of the Companies' generating facilities, and certain of their other facilities, are subject to the Clean Water Act.

In May 2014, the EPA finalized regulations pursuant to Section 316(b) of the Clean Water Act regarding cooling water intake structures pursuant to a court approved settlement. KCP&L generation facilities with cooling water intake structures are subject to the best technology available standards based on studies completed to comply with such standards. The rule provides flexibility to work with the states to develop the best technology available to minimize aquatic species impacted by being pinned against intake screens (impingement) or drawn into cooling water systems (entrainment).

KCP&L holds a permit from the Missouri Department of Natural Resources (MDNR) covering water discharge from its Hawthorn Station. The permit authorizes KCP&L to, among other things, withdraw water from the Missouri River for cooling purposes and return the heated water to the Missouri River. KCP&L has applied for a renewal of this permit and the EPA has submitted an interim objection letter regarding the allowable amount of heat that can be contained in the returned water. Until this matter is resolved, KCP&L continues to operate under its current permit. Great Plains Energy and KCP&L cannot predict the outcome of this matter; however, while less significant outcomes are possible, this matter may require a reduction in generation, installation of cooling towers or other technology to cool the water, or both, any of which could have a significant impact on Great Plains Energy's and KCP&L's results of operations, financial position and cash flows.

Further, the possible effects of climate change, including potentially increased temperatures and reduced precipitation, could make it more difficult and costly to comply with the current and final permit requirements.

Solid Waste

Solid and hazardous waste generation, storage, transportation, treatment and disposal are regulated at the federal and state levels under various laws and regulations. In April 2015, the EPA published final regulations to regulate coal combustion residuals (CCRs) under the Resource Conservation and Recovery

Act (RCRA) Subtitle D to address the risks from the disposal of CCRs generated from the combustion of coal at electric generating facilities. In September 2017, the EPA granted industry petitions to reconsider certain provisions of the CCR rule. The Companies use coal in generating electricity and dispose of CCRs in both on-site facilities and facilities owned by third parties. Current and future EPA and state regulations regarding the handling, disposal and remediation of CCRs could have a material adverse effect on the Companies' results of operations, financial position and cash flows.

Remediation
Under current law, the Companies are also generally responsible for any liabilities associated with the environmental condition of their properties and other properties at which the Companies arranged for the disposal or treatment of hazardous substances, including properties that they have previously owned or operated, such as manufactured gas plants (MGP), regardless of whether they were responsible for the contamination or whether the liabilities arose before, during or after the time they owned or operated the properties or arranged for the disposal or treatment of hazardous substances.

Due to all of the above, the Companies' projected capital and other expenditures for environmental compliance are subject to significant uncertainties, including the timing of implementation of any new or modified environmental requirements, the limits imposed by such requirements and the types and costs of the compliance alternatives selected by the Companies. As a result, costs to comply with environmental requirements cannot be estimated with certainty, and actual costs could be significantly higher than projections. New environmental laws and regulations affecting the operations of the Companies may be adopted, and new interpretations of existing laws and regulations could be adopted or become applicable to the Companies or their facilities, any of which may materially adversely affect the Companies' business, adversely affect the Companies' ability to continue operating its power plants as currently done and substantially increase environmental expenditures or liabilities in the future.

Financial Risks:

Financial market disruptions and declines in credit ratings may increase financing costs and/or limit access to the credit markets, which may adversely affect liquidity and results.
The Companies rely on access to short-term money markets, revolving credit facilities provided by financial institutions and long-term capital markets as significant sources of liquidity for capital requirements not satisfied by cash flows from operations. The Companies also rely on bank-provided credit facilities for credit support, such as letters of credit, to support operations. The amount of credit support required for operations varies and is impacted by a number of factors.

Great Plains Energy, KCP&L, GMO and certain of their securities are rated by Moody's Investors Service and S&P Global Ratings. These ratings impact the Companies' cost of funds and Great Plains Energy's ability to provide credit support for its subsidiaries. The interest rates on borrowings under the Companies' revolving credit agreements are subject to increase as their respective credit ratings decrease. The amount of collateral or other credit support required under power supply and certain other agreements is also dependent on credit ratings.

Conditions in the U.S. capital and credit markets may deteriorate in the future for a variety of reasons, including, among others: instability in global markets, political uncertainty in the U.S. or abroad, fluctuations in the price of oil, geopolitical instability or other unforeseen events both in the U.S. and around the world. Adverse market conditions or decreases in Great Plains Energy's, KCP&L's or GMO's credit ratings could have material adverse effects on the Companies. These effects could include, among others: reduced access to capital and increased cost of funds; dilution resulting from equity issuances at reduced prices; changes in the type and/or increases in the amount of collateral or other credit support obligations required to be posted with contractual counterparties; increased nuclear decommissioning trust and pension and other post-retirement benefit plan funding requirements; rate case disallowance of KCP&L's or GMO's costs of capital; reductions in or delays of capital expenditures; or reductions in Great Plains Energy's ability to provide credit support for its subsidiaries. Any of these results could adversely affect the Companies' results of operations, financial position and cash flows. In addition, market disruption and volatility could have an adverse impact on the Companies' lenders, suppliers and other counterparties or customers, causing them to fail to meet their obligations.

Great Plains Energy has guaranteed some of GMO's long-term and short-term debt and payments under these guarantees may adversely affect Great Plains Energy's liquidity.
Great Plains Energy has issued guarantees covering $95.5 million of GMO's long-term debt. Great Plains Energy also guarantees GMO's commercial paper program. At December 31, 2017, GMO had $209.3 million of commercial paper outstanding. The guarantees obligate Great Plains Energy to pay amounts owed by GMO directly to the holders of the guaranteed debt in the event GMO defaults on its payment obligations. Great Plains Energy may also guarantee debt that GMO may issue in the future. Any guarantee payments could adversely affect Great Plains Energy's liquidity.

The inability of Great Plains Energy's subsidiaries to provide sufficient dividends to Great Plains Energy, or the inability otherwise of Great Plains Energy to pay dividends to its shareholders and meet its financial obligations would have an adverse effect.
Great Plains Energy is a holding company with no significant operations of its own. The primary source of funds for payment of dividends to its shareholders and its other financial obligations is dividends paid to it by its subsidiaries, particularly KCP&L and GMO. The ability of Great Plains Energy's subsidiaries to pay dividends or make other distributions, and accordingly, Great Plains Energy's ability to pay dividends on its common stock and meet its financial obligations principally depends on the actual and projected earnings and cash flow, capital requirements and general financial position of its subsidiaries, as well as regulatory factors, financial covenants, general business conditions and other matters.

In addition, Great Plains Energy, KCP&L and GMO are subject to certain corporate and regulatory restrictions and financial covenants that could affect their ability to pay dividends. Great Plains Energy's articles of incorporation restrict the payment of common stock dividends in the event common equity is 25% or less of total capitalization. Under the Federal Power Act, KCP&L and GMO generally can pay dividends only out of retained earnings. The revolving credit agreements of Great Plains Energy, KCP&L and GMO and the note purchase agreement for GMO's Series A, B and C Senior Notes contain a covenant requiring each company to maintain a consolidated indebtedness to consolidated total capitalization ratio of not more than 0.65 to 1.00 at all times. Under the Amended Merger Agreement, Great Plains Energy is also restricted from paying a quarterly common stock dividend in excess of $0.275 per share without the consent of Westar. See Note 11 to the consolidated financial statements for additional information. The Great Plains Energy Board of Directors (Great Plains Energy Board) regularly evaluates the common stock dividend policy and determines an appropriate dividend each quarter, after taking into account such factors as, among other things, earnings, financial condition and cash flows from KCP&L and GMO, as well as general economic conditions. Great Plains Energy cannot assure common shareholders that the dividend will be paid in the future or that, if paid, dividends will be at the same amount or with the same frequency as in the past.

Market performance, increased employee retirements and retirement plan regulations could significantly impact retirement plan funding requirements and associated cash needs and expenses.
Substantially all of the Companies' and WCNOC's employees participate in defined benefit retirement and other post-retirement plans. Former employees also have accrued benefits in defined benefit retirement and other post-retirement plans. The costs of these plans depend on a number of factors, including the rates of return on plan assets, the level and nature of the provided benefits, discount rates, the interest rates used to measure required minimum funding levels, changes in benefit design, changes in laws or regulations, and the Companies' required or voluntary contributions to the plans. The Companies currently have substantial unfunded liabilities under these plans. Also, if the rate of retirements exceeds planned levels, or if these plans experience adverse market returns on investments, or if interest rates materially fall, the Companies' contributions to the plans could rise substantially over historical levels. In addition, changes in accounting rules and assumptions related to future costs, returns on investments, interest rates and other actuarial assumptions, including projected retirements, could have a significant impact on the Companies' results of operations, financial position and cash flows.

The use of derivative contracts in the normal course of business could result in losses that could negatively impact the Companies' results of operations, financial position and cash flows.
The Companies use derivative instruments, such as swaps, options, futures and forwards, to manage commodity and financial risks. Losses could be recognized as a result of volatility in the market values of these contracts, if a counterparty fails to perform, or if the underlying transactions which the derivative instruments are intended to

hedge fail to materialize. In the absence of actively quoted market prices and pricing information from external sources, the valuation of these financial instruments can involve management's judgment or the use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of these contracts.

As a service provider to GMO, KCP&L may have exposure to GMO's financial performance and operations.
GMO has no employees of its own. KCP&L employees operate and manage GMO's properties, and KCP&L charges GMO for the cost of these services. These arrangements may pose risks to KCP&L, including possible claims arising from actions of KCP&L employees in operating GMO's properties and providing other services to GMO. KCP&L's claims for reimbursement for services provided to GMO are unsecured and rank equally with other unsecured obligations of GMO. KCP&L's ability to be reimbursed for the costs incurred for the benefit of GMO depends on the financial ability of GMO to make such payments.

Customer and Weather-Related Risks:

The results of operations, financial position and cash flows of the Companies can be materially affected by changes in customer electricity consumption.
Changes in customer electricity consumption due to sustained financial market disruptions, downturns or sluggishness in the economy, technological advances, energy efficiency or other factors may adversely affect the Companies' results of operations, financial position and cash flows.

Technological advances, energy efficiency, or other energy conservation measures could reduce customer electricity consumption. KCP&L and GMO generate electricity at central station power plants to achieve economies of scale and produce electricity at a competitive cost. There are distributed generation technologies that produce electricity, including microturbines, wind turbines, fuel cells and solar cells, that have recently become more cost competitive. If this trend continues, the Companies' customer electricity consumption could be reduced. Changes in technology could also alter the channels through which the Companies' customers purchase or use electricity, which could reduce the Companies' customer electricity consumption.

Weather is a major driver of the Companies' results of operations, financial position and cash flow.
Weather conditions directly influence the demand for electricity and natural gas and affect the price of energy commodities. Great Plains Energy and KCP&L are significantly impacted by seasonality, with approximately one-third of their retail electric revenues recorded in the third quarter. Unusually mild winter or summer weather can adversely affect sales. In addition, severe weather, including but not limited to tornados, snow, rain, flooding and ice storms can be destructive causing outages and property damage that can potentially result in additional expenses, lower revenues and additional capital restoration costs. KCP&L's and GMO's rates may not always be adjusted timely and adequately to reflect these increased costs. Some of the Companies' generating stations utilize water from the Missouri River for cooling purposes. Low water and flow levels can increase maintenance costs at these stations and, if these levels were to get low enough, could require modifications to plant operations. The possible effects of climate change (such as increased temperatures, increased occurrence of severe weather or reduced precipitation, among other possible results) could potentially increase the volatility of demand and prices for energy commodities, increase the frequency and impact of severe weather, increase the frequency of flooding or decrease water and flow levels. To the extent the frequency of extreme weather events increases, this could increase the Companies' cost in providing service.

Operational Risks:

Operational risks may adversely affect the Companies' results of operations, financial position and cash flows.

The operation of the Companies' electric generation, transmission, distribution and information systems involves many risks, including breakdown or failure of equipment, aging infrastructure, processes and personnel performance; problems that delay or increase the cost of returning facilities to service after outages; limitations that may be imposed by equipment conditions or environmental, safety or other regulatory requirements; fuel supply or fuel transportation reductions or interruptions; labor disputes; difficulties with the implementation or continued operation of information systems; transmission scheduling constraints; and catastrophic events such as fires, floods, droughts, explosions, terrorism, cyber threats, severe weather or other similar occurrences. Furthermore, to the extent that a cyber attack was successful, customer and employee information may be stolen, equipment may be destroyed or damaged and operations may be disrupted. Any such equipment or system outage or constraint can, among other things:

- in the case of generation equipment, affect operating costs, increase capital requirements and costs, increase purchased power volumes and costs and reduce wholesale sales opportunities;

- in the case of transmission equipment, affect operating costs, increase capital requirements and costs, require changes in the source of generation and affect wholesale sales opportunities and the ability to meet regulatory reliability and security requirements;

- in the case of distribution systems, affect revenues and operating costs, increase capital requirements and costs, and affect the ability to meet regulatory service metrics and customer expectations; and

- in the case of information systems, affect the control and operations of generation, transmission, distribution, customer information and other business operations and processes, increase operating costs, increase capital requirements and costs, and affect the ability to meet regulatory reliability and security requirements and customer expectations.

With the exception of Hawthorn No. 5, which was substantially rebuilt in 2001, and Iatan No. 2, which was completed in 2010, all of KCP&L's and GMO's coal-fired generating units and its nuclear generating unit were constructed prior to 1986. The age of these generating units increases the risk of unplanned outages, reduced generation output and higher maintenance expense. Training, preventive maintenance and other programs have been implemented, but there is no assurance that these programs will prevent or minimize future breakdowns or failures of the Companies' generation facilities or increased maintenance expense. Furthermore, aging transmission and distribution facilities are more prone to failure than new facilities, which results in higher maintenance expense and the need to replace these facilities with new infrastructure. The higher maintenance costs and capital expenditures for new replacement infrastructure could cause additional rate volatility for the Companies' customers, resistance by the Companies' regulators to allow customer rate increases and/or regulatory lag.

The Companies currently have general liability and property insurance in place to cover their facilities in amounts that management considers appropriate. These policies, however, do not cover the Companies' transmission or distribution systems, and the cost of repairing damage to these systems may adversely affect the Companies' results of operations, financial position and cash flows. Such policies are subject to certain limits and deductibles and do not include business interruption coverage. Insurance coverage may not be available in the future at reasonable costs or on commercially reasonable terms, and the insurance proceeds received for any loss of, or any damage to, any of the Companies' facilities may not be sufficient to restore the loss or damage.

These and other operating events may reduce the Companies' revenues, increase their costs, or both, and may materially affect their results of operations, financial position and cash flows.

Cyber attacks and other disruptions to facilities could interfere with operations, expose the Companies, customers or employees to a risk of loss and could cause reputational and financial harm.
Electric utilities and other operators of critical energy infrastructure, like KCP&L and GMO, may face a heightened risk of cyber attack. The Companies' facilities could be direct targets or indirect casualties of any such cyber attacks. The Companies' business relies on information technology for the generation, transmission and distribution of electricity, their primary business, as well as in secondary operational functions, including supply chain, and invoicing and collecting payments from customers. In the ordinary course of business, the Companies collect, store and transmit sensitive data including operating information, proprietary business information belonging to the Companies and third parties and personal information belonging to customers and employees. To the extent that a cyber attack was successful, customer and employee information may be stolen, equipment may be destroyed or damaged and operations of the generation fleet and/or reliability of the transmission and distribution system may be disrupted. In such an event, the Companies may experience substantial loss of revenues, material response costs and other financial loss, including the increased cost of insurance coverage. The Companies could also be subject to litigation, increased regulation and reputational damage. Any of the foregoing could have a material adverse impact on the Companies' results of operations, financial position and cash flows.

The Companies are subject to information security risks and risks of unauthorized access to their systems.
In the course of their businesses, the Companies handle a range of system security and sensitive customer information. KCP&L and GMO are subject to laws and rules issued by different agencies concerning safeguarding and maintaining the confidentiality of this information. A security breach of the utilities' information systems such as theft or the inappropriate release of certain types of information, including confidential customer information or system operating information, could have a material adverse impact on the results of operations, financial position and cash flows of the Companies.

KCP&L and GMO operate in a highly regulated industry that requires the continued operation of sophisticated information technology systems and network infrastructures. Despite implementation of security measures, the technology systems are vulnerable to disability, failures, employee error or malfeasance, or unauthorized access. Such failures or breaches of the systems could impact the reliability of generation, transmission and distribution systems, result in legal claims and proceedings, damage the Companies' reputation and also subject the Companies to financial harm. If the technology systems were to fail or be breached and not able to be recovered in a timely manner, critical business functions could be impaired and sensitive confidential data could be compromised, which could have a material adverse impact on the Companies' results of operations, financial position and cash flows.

The cost and schedule of capital projects may materially change and expected performance may not be achieved.
Great Plains Energy's and KCP&L's businesses are capital intensive. The Companies currently have significant capital projects pending and may also have significant capital projects in the future. The risks of any capital project include: that actual costs may exceed estimated costs due to inflation or other factors; risks associated with the incurrence of additional debt or the issuance of additional equity to fund such projects; delays that may occur in obtaining permits and materials; the failure of suppliers and contractors to perform as required under their contracts; inadequate availability or increased cost of equipment, materials or qualified craft labor; delays related to inclement weather; the scope, cost and timing of projects may change due to new or changed environmental requirements, health and safety laws or other factors; and other events beyond the Companies' control may occur that may materially affect the schedule, cost and performance of these projects.

These and other risks could materially increase the estimated costs of capital projects, delay the in-service dates of projects, adversely affect the performance of the projects, and/or require the Companies to purchase additional electricity to supply their respective retail customers until the projects are completed. Thus, these risks may significantly affect the Companies' results of operations, financial position and cash flows.

Failure of one or more generation plant co-owners to pay their share of construction or operations and maintenance costs could increase the Companies' costs and capital requirements.
KCP&L owns 47% of Wolf Creek, 50% of La Cygne Station, 70% of Iatan No. 1 and 55% of Iatan No. 2. GMO owns 18% of both Iatan units and 8% of Jeffrey Energy Center. The remaining portions of these facilities are owned by other utilities that are contractually obligated to pay their proportionate share of capital and other costs.

While the ownership agreements provide that a defaulting co-owner's share of the electricity generated can be sold by the non-defaulting co-owners, there is no assurance that the revenues received will recover the increased costs borne by the non-defaulting co-owners. Occurrence of these or other events could materially increase the Companies' costs and capital requirements.

KCP&L is exposed to risks associated with the ownership and operation of a nuclear generating unit, which could result in an adverse effect on the Companies' business and financial results.
KCP&L owns 47% of Wolf Creek. The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities, including Wolf Creek. In the event of non-compliance, the NRC has the authority to impose fines, shut down the facilities, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. Additionally, the non-compliance of other nuclear facility operators with applicable regulations or the occurrence of a serious nuclear incident anywhere in the world could result in increased regulation of the nuclear industry as a whole. Any revised safety requirements promulgated by the NRC could result in substantial capital expenditures at Wolf Creek.

Wolf Creek has the lowest fuel cost per MWh of any of KCP&L's generating units, excluding renewable generation. An extended outage of Wolf Creek, whether resulting from NRC action, an incident at the plant or otherwise, could have a material adverse effect on KCP&L's results of operations, financial position and cash flows in the event KCP&L incurs higher replacement power and other costs that are not recovered through rates or insurance. If a long-term outage occurred, the state regulatory commissions could reduce rates by excluding the Wolf Creek investment from rate base. Wolf Creek was constructed prior to 1986 and the age of Wolf Creek increases the risk of unplanned outages and results in higher maintenance costs.

Ownership and operation of a nuclear generating unit exposes KCP&L to risks regarding decommissioning costs at the end of the unit's life. KCP&L contributes annually based on estimated decommissioning costs to a tax-qualified trust fund to be used to decommission Wolf Creek. The funding level assumes a projected level of return on trust assets. If the actual return on trust assets is below the projected level or actual decommissioning costs are higher than estimated, KCP&L could be responsible for the balance of funds required and may not be allowed to recover the balance through rates.

KCP&L is also exposed to other risks associated with the ownership and operation of a nuclear generating unit, including, but not limited to, (i) potential liability associated with the potential harmful effects on the environment and human health resulting from the operation of a nuclear generating unit, (ii) the storage, handling, disposal and potential release (by accident, through third-party actions or otherwise) of radioactive materials and (iii) uncertainties with respect to contingencies and assessments if insurance coverage is inadequate. Under the structure for insurance among owners of nuclear generating units, KCP&L is also liable for potential retrospective premium assessments (subject to a cap) per incident at any commercial reactor in the country and losses in excess of insurance coverage.

On March 29, 2017, Westinghouse Electric Company, LLC (Westinghouse) filed voluntary petitions to reorganize under Chapter 11 of the U.S. Bankruptcy Code. Wolf Creek contracts with Westinghouse for nuclear fuel fabrications and reactor services. Westinghouse has stated that it intends to continue normal business operations. However, if Westinghouse did not perform under its contracts with Wolf Creek it could result in an extended outage at Wolf Creek. An extended outage of Wolf Creek could have a material adverse effect on Great Plains Energy's and KCP&L's results of operations, financial position and cash flows in the event KCP&L incurs higher replacement power and other costs that are not recovered through rates. In January 2018, Westinghouse issued a news release stating that it would sell its global business to an unaffiliated third party. This transaction must be approved by the bankruptcy court and applicable regulators. The process has not yet begun, but Westinghouse stated it plans to close the transaction in the third quarter of 2018. It is not yet known at this time if Wolf Creek's contracts will be impacted.

The structure of the regional power market in which the Companies operate could have an adverse effect on the Companies' results of operations, financial position and cash flows.
In March 2014, the SPP launched its Integrated Marketplace. Similar to other RTO or ISO markets, this marketplace determines which generating units among market participants should run, within the operating constraints of a unit, at any given time for maximum cost-effectiveness. In the event that KCP&L's and GMO's generating units are not among the lowest cost generating units operating within the market, KCP&L and GMO could experience decreased levels of wholesale electricity sales.

A market for Transmission Congestion Rights (TCR) is also included as part of the Integrated Marketplace. TCRs are financial instruments used to hedge transmission congestion charges. Both KCP&L and GMO acquire TCRs for the purpose of hedging against transmission congestion charges. There is a risk that KCP&L and GMO could incorrectly model the amount of TCRs needed, or that the TCRs acquired could be ineffective in hedging against transmission congestion charges which could lead to increased purchased power costs.

The rules governing the various regional power markets may change from time to time and such changes could impact the Companies' costs and revenues. Because the manner in which RTOs or ISOs will evolve is unclear, the Companies are unable to assess fully the impact of these changes.

Litigation Risks:

The outcome of legal proceedings cannot be predicted. An adverse finding could have a material adverse effect on the Companies' results of operations, financial position and cash flows.
The Companies are party to various material litigation and regulatory matters arising out of their business operations. The ultimate outcome of these matters cannot presently be determined, nor, in many cases, can the liability that could potentially result from a negative outcome in each case be reasonably estimated. The liability that the Companies may ultimately incur with respect to any of these cases in the event of a negative outcome may be in excess of amounts currently reserved and insured against with respect to such matters.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Electric Utility Generation Resources

	Unit	Location	Year Completed	Estimated 2018 MW Capacity	Primary Fuel
Base Load	Iatan No. 2	Missouri	2010	482 [(a)]	Coal
	Wolf Creek	Kansas	1985	552 [(a)]	Nuclear
	Iatan No. 1	Missouri	1980	490 [(a)]	Coal
	La Cygne Nos. 1 and 2	Kansas	1973, 1977	699 [(a)]	Coal
	Hawthorn No. 5 [(b)]	Missouri	1969	564	Coal
	Montrose Nos. 2 and 3	Missouri	1960, 1964	334	Coal
Peak Load	West Gardner Nos. 1, 2, 3 and 4	Kansas	2003	314	Natural Gas
	Osawatomie	Kansas	2003	76	Natural Gas
	Hawthorn Nos. 6 and 9	Missouri	2000	235	Natural Gas
	Hawthorn No. 8	Missouri	2000	79	Natural Gas
	Hawthorn No. 7	Missouri	2000	78	Natural Gas
	Northeast Black Start Unit	Missouri	1985	2	Oil
	Northeast Nos. 17 and 18	Missouri	1977	105	Oil
	Northeast Nos. 13 and 14	Missouri	1976	95	Oil
	Northeast Nos. 15 and 16	Missouri	1975	106	Oil
	Northeast Nos. 11 and 12	Missouri	1972	88	Oil
Wind	Spearville 2 Wind Energy Facility [(c)]	Kansas	2010	48	Wind
	Spearville 1 Wind Energy Facility [(d)]	Kansas	2006	101	Wind
Total KCP&L				4,448	
Base Load	Iatan No. 2	Missouri	2010	159 [(a)]	Coal
	Iatan No. 1	Missouri	1980	126 [(a)]	Coal
	Jeffrey Energy Center Nos. 1, 2 and 3	Kansas	1978, 1980, 1983	173 [(a)]	Coal
	Sibley Nos. 2 and 3	Missouri	1962, 1969	406	Coal
Peak Load	Lake Road Nos. 2 and 4	Missouri	1957, 1967	115	Natural Gas
	South Harper Nos. 1, 2 and 3	Missouri	2005	303	Natural Gas
	Crossroads Energy Center	Mississippi	2002	292	Natural Gas
	Ralph Green No. 3	Missouri	1981	71	Natural Gas
	Greenwood Nos. 1, 2, 3 and 4	Missouri	1975-1979	242	Natural Gas/Oil
	Lake Road No. 5	Missouri	1974	62	Natural Gas/Oil
	Lake Road Nos. 1 and 3	Missouri	1951, 1962	24	Natural Gas/Oil
	Lake Road Nos. 6 and 7	Missouri	1989, 1990	42	Oil
	Nevada	Missouri	1974	18	Oil
Total GMO				2,033	
Total Great Plains Energy				6,481	

[(a)] Share of a jointly owned unit.
[(b)] In 2001, a new boiler, air quality control equipment and an uprated turbine was placed in service at the Hawthorn Generating Station.
[(c)] Accredited capacity is 16 MW pursuant to SPP reliability standards.
[(d)] Accredited capacity is 31 MW pursuant to SPP reliability standards.

KCP&L owns 50% of La Cygne No. 1 and No. 2 Units, 70% of Iatan No. 1 Unit, 55% of Iatan No. 2 Unit and 47% of Wolf Creek. GMO owns 18% of each of Iatan No. 1 and No. 2 Units and 8% of Jeffrey Energy Center No. 1, No. 2 and No. 3 Units.

Electric Utility Transmission and Distribution Resources
Electric Utility's electric transmission system interconnects with systems of other utilities for reliability and to permit wholesale transactions with other electricity suppliers. Electric Utility has approximately 3,600 circuit miles of transmission lines, 15,600 circuit miles of overhead distribution lines and 7,400 circuit miles of underground distribution lines in Missouri and Kansas. Electric Utility has all material franchise rights necessary to sell electricity within its retail service territory. Electric Utility's transmission and distribution systems are routinely monitored for adequacy to meet customer needs. Management believes the current systems are adequate to serve customers.

Electric Utility General
Electric Utility's generating plants are located on property owned (or co-owned) by KCP&L or GMO, except the Spearville Wind Energy Facilities which are located on easements, and the Crossroads Energy Center and the South Harper Facility which are contractually controlled. Electric Utility's service centers, electric substations and a portion of its transmission and distribution systems are located on property owned or leased by Electric Utility. Electric Utility's transmission and distribution systems are for the most part located above or underneath highways, streets, other public places or property owned by others. Electric Utility believes that it has satisfactory rights to use those places or properties in the form of permits, grants, easements, licenses or franchise rights; however, it has not necessarily undertaken efforts to examine the underlying title to the land upon which the rights rest. Great Plains Energy's and KCP&L's headquarters are located in leased office space.

Substantially all of the fixed property and franchises of KCP&L, which consist principally of electric generating stations, electric transmission and distribution lines and systems, and buildings (subject to exceptions, reservations and releases), are subject to a General Mortgage Indenture and Deed of Trust dated as of December 1, 1986, as supplemented (Indenture). Mortgage bonds totaling $479.5 million were outstanding at December 31, 2017.

A portion of the fixed property and franchises of GMO are subject to a General Mortgage Indenture and Deed of Trust dated as of April 1, 1946, as supplemented. Mortgage bonds totaling $4.6 million were outstanding at December 31, 2017.

ITEM 3. LEGAL PROCEEDINGS

Other Proceedings
The Companies are parties to various lawsuits and regulatory proceedings in the ordinary course of their respective businesses. For information regarding material lawsuits and proceedings, see Notes 2, 6, 15 and 16 to the consolidated financial statements. Such information is incorporated herein by reference.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

GREAT PLAINS ENERGY

Great Plains Energy's common stock is listed on the New York Stock Exchange under the symbol "GXP". At February 16, 2018, Great Plains Energy's common stock was held by 13,952 shareholders of record. Information relating to market prices and cash dividends on Great Plains Energy's common stock is set forth in the following table.

	Common Stock Price Range [a]				Common Stock Dividends Declared		
	2017		2016				
Quarter	High	Low	High	Low	2018	2017	2016
First	$ 29.24	$ 26.87	$ 32.26	$ 26.34	$ 0.275 [b]	$ 0.275	$ 0.2625
Second	29.92	27.86	32.68	28.35		0.275	0.2625
Third	31.58	29.14	31.22	26.53		0.275	0.2625
Fourth	34.70	30.55	28.60	26.20		0.275	0.275

[a] Based on closing stock prices.
[b] Declared February 13, 2018, and payable March 20, 2018, to shareholders of record as of February 27, 2018.

Dividend Restrictions

For information regarding dividend restrictions, see Note 13 to the consolidated financial statements.

Purchases of Equity Securities

The following table provides information regarding purchases by Great Plains Energy for the three months ended December 31, 2017.

Issuer Purchases of Equity Securities				
Month	Total Number of Shares (or Units) Purchased [a]	Average Price Paid per Share (or Unit)	Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs
October 1 - 31	2,981	$ 31.54	—	N/A
November 1 - 30	2,421	33.63	—	N/A
December 1 - 31	17,424	32.53	—	N/A
Total	22,826	$ 32.52	—	N/A

[a] Represents open market purchases for the Company's Dividend Reinvestment and Direct Stock Purchase Plan and defined contribution savings plan (401(k)).

KCP&L

KCP&L is a wholly owned subsidiary of Great Plains Energy, which holds the one share of issued and outstanding KCP&L common stock.

Dividend Restrictions

For information regarding dividend restrictions, see Note 13 to the consolidated financial statements.

ITEM 6. SELECTED FINANCIAL DATA

Year Ended December 31	2017	2016	2015	2014[(a)]	2013[(a)]
Great Plains Energy	(dollars in millions except per share amounts)				
Operating revenues	$ 2,708	$ 2,676	$ 2,502	$ 2,568	$ 2,446
Net income (loss)	$ (106)	$ 290	$ 213	$ 243	$ 250
Basic and diluted earnings (loss) per common share	$ (0.67)	$ 1.61	$ 1.37	$ 1.57	$ 1.62
Total assets at year end [(a)]	$ 12,458	$ 13,570	$ 10,739	$ 10,453	$ 9,770
Total redeemable preferred stock, mandatorily redeemable preferred securities and long-term debt (including current maturities) [(a)]	$ 3,664	$ 3,747	$ 3,746	$ 3,481	$ 3,492
Cash dividends per common share	$ 1.10	$ 1.0625	$ 0.9975	$ 0.935	$ 0.8825
SEC ratio of earnings to combined fixed charges and preferred dividend requirements	1.66	2.54	2.58	2.72	2.75
KCP&L					
Operating revenues	$ 1,891	$ 1,875	$ 1,714	$ 1,731	$ 1,671
Net income	$ 180	$ 225	$ 153	$ 162	$ 169
Total assets at year end [(a)]	$ 8,124	$ 8,058	$ 7,815	$ 7,495	$ 6,821
Total redeemable preferred stock, mandatorily redeemable preferred securities and long-term debt (including current maturities) [(a)]	$ 2,582	$ 2,565	$ 2,563	$ 2,297	$ 2,294
SEC ratio of earnings to fixed charges	3.05	3.30	2.57	2.69	2.76

[(a)] Applicable balances for the years ended December 31, 2014 and 2013 have been adjusted for the adoption of Accounting Standards Update (ASU) No. 2015-03, *Simplifying the Presentation of Debt Issuance Costs*.

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

GREAT PLAINS ENERGY INCORPORATED

EXECUTIVE SUMMARY

Description of Business
Great Plains Energy is a public utility holding company and does not own or operate any significant assets other than the stock of its subsidiaries and cash and cash equivalents.

Great Plains Energy's sole reportable business segment is Electric Utility. Electric Utility consists of KCP&L, a regulated utility, GMO's regulated utility operations and GMO Receivables Company. Electric Utility has approximately 6,500 MWs of owned generating capacity and engages in the generation, transmission, distribution and sale of electricity to approximately 867,100 customers in the states of Missouri and Kansas. Electric Utility's retail electricity rates are comparable to the national average of investor-owned utilities.

Great Plains Energy's corporate and other activities not included in the sole reportable business segment includes GMO activity other than its regulated utility operations, GPETHC and unallocated corporate charges including certain costs to achieve the anticipated merger with Westar.

Anticipated Merger with Westar Energy, Inc.
On July 9, 2017, Great Plains Energy entered into an Amended Merger Agreement by and among Great Plains Energy, Westar, Holdco, and Merger Sub. Pursuant to the Amended Merger Agreement, subject to the satisfaction or waiver of certain conditions, Great Plains Energy will merge with and into Holdco, with Holdco surviving such

merger, and Merger Sub will merge with and into Westar, with Westar surviving such merger. Upon closing, pursuant to the Amended Merger Agreement, each outstanding share of Great Plains Energy's and Westar's common stock will be converted into the right to receive 0.5981 and 1.0, respectively, of validly issued, fully paid and nonassessable shares of common stock, no par value, of Holdco. Following the mergers, Holdco, with a new name that has yet to be established, will be the parent of Great Plains Energy's direct subsidiaries, including KCP&L, and Westar.

The anticipated merger has been structured as a merger of equals in a tax-free exchange of shares that involves no premium paid or received with respect to either Great Plains Energy or Westar. Following the completion of the anticipated merger, Westar shareholders will own approximately 52.5 percent and Great Plains Energy shareholders will own approximately 47.5 percent of the combined company.

Great Plains Energy's anticipated merger with Westar was unanimously approved by the Great Plains Energy Board and Westar Board of Directors, has received the approvals of each of Great Plains Energy's and Westar's shareholders and has received early termination of the waiting period under the HSR Act with respect to antitrust review. The anticipated merger remains subject to regulatory approvals from KCC, the MPSC, NRC, FERC and FCC; as well as other contractual conditions.

See Note 2 to the consolidated financial statements for more information regarding the anticipated merger and redemption of acquisition financing associated with the Original Merger Agreement.

Expected Plant Retirements

In June 2017, Great Plains Energy and KCP&L announced plans to retire KCP&L's Montrose Station and GMO's Sibley Station by December 31, 2018 and GMO's Lake Road No. 4/6 Unit by December 31, 2019. The decision to retire these generating units, which represent approximately 900 MWs of generating capacity, was primarily driven by the age of the plants, expected environmental compliance costs and expected future generation capacity needs. See Note 1 to the consolidated financial statements for more information regarding the retirement of Sibley No. 3 Unit.

Tax Reform

In December 2017, the U.S. Congress passed and President Donald Trump signed Public Law No. 115-97, commonly referred to as the Tax Cuts and Jobs Act (Tax Act). The Tax Act represents the first major reform in U.S. income tax law since 1986. Most notably, the Tax Act reduces the current top corporate income tax rate from 35% to 21% beginning in 2018, repeals the corporate Alternative Minimum Tax (AMT), makes existing AMT tax credit carryforwards refundable, and changes the deductibility and taxability of certain items, among other things. See Note 21 to the consolidated financial statements for more information regarding the impact of tax reform on Great Plains Energy and KCP&L.

Earnings Overview

Great Plains Energy had a loss available for common shareholders of $143.5 million or $0.67 per share in 2017 compared to earnings of $273.5 million or $1.61 per share in 2016. This decrease in earnings was largely driven by a number of non-recurring impacts due to the anticipated merger with Westar and the impacts of U.S. federal income tax reform. The specific drivers of the decrease in earnings were lower gross margin; higher depreciation expense; a loss on the settlement of the 7.00% Series B Mandatory Convertible Preferred Stock (Series B Preferred Stock) dividend make-whole provisions; a loss on extinguishment of debt related to the redemption of Great Plains Energy's $4.3 billion senior notes; an increase in interest charges; higher income tax expense and increased preferred stock dividend requirements and redemption premium; partially offset by a decrease in injuries and damages expense due to settled litigation and an increase in interest income.

In addition, a higher number of average shares outstanding due to Great Plains Energy's registered public offering of 60.5 million shares of common stock in October 2016 diluted the 2017 loss per share by $0.26.

For additional information regarding the change in earnings (loss), refer to the Great Plains Energy Results of Operations and the Electric Utility Results of Operations sections within this Management's Discussion and

Analysis of Financial Condition and Results of Operations. Gross margin is a non-GAAP financial measure. See the explanation of gross margin under Great Plains Energy's Results of Operations.

Adjusted Earnings (Non-GAAP) and Adjusted Earnings Per Share (Non-GAAP)
Great Plains Energy's adjusted earnings (non-GAAP) and adjusted earnings per share (non-GAAP) for 2017 were $269.4 million or $1.74 per share, respectively. Great Plains Energy's adjusted earnings (non-GAAP) and adjusted earnings per share (non-GAAP) for 2016 were $286.0 million and $1.85, respectively. For 2015, adjusted earnings (non-GAAP) and adjusted earnings per share (non-GAAP) were the same as GAAP earnings and GAAP earnings per share at $211.4 million and $1.37, respectively. In addition to earnings (loss) available for common shareholders and diluted earnings (loss) per common share, Great Plains Energy's management uses adjusted earnings (non-GAAP) and adjusted earnings per share (non-GAAP) to evaluate earnings and earnings per share without the impact of the anticipated merger with Westar and the initial impact of U.S. federal income tax reform.

Adjusted earnings (non-GAAP) and adjusted earnings per share (non-GAAP) excludes certain costs, expenses, gains, losses and the per share dilutive effect of equity issuances resulting from the anticipated merger and the previous plan to acquire Westar and the income tax expense associated with the revaluation of deferred income taxes and other initial effects resulting from the enactment of U.S. federal income tax reform. This information is intended to enhance an investor's overall understanding of results. Adjusted earnings (non-GAAP) and adjusted earnings per share (non-GAAP) are used internally to measure performance against budget and in reports for management and the Great Plains Energy Board. Adjusted earnings (non-GAAP) and adjusted earnings per share (non-GAAP) are financial measures that are not calculated in accordance with GAAP and may not be comparable to other companies' presentations or more useful than the GAAP information provided elsewhere in this report.

The following table provides a reconciliation between earnings (loss) available for common shareholders and diluted earnings (loss) per common share as determined in accordance with GAAP and adjusted earnings (non-GAAP) and adjusted earnings per share (non-GAAP):

Reconciliation of GAAP to Non-GAAP	**Earnings (Loss)**			**Earnings (Loss) per Diluted Share**		
	2017	**2016**	**2015**	**2017**	**2016**	**2015**
	(millions, except per share amounts)					
Earnings (loss) available for common shareholders	$ (143.5)	$ 273.5	$ 211.4	$ (0.67)	$ 1.61	$ 1.37
Costs to achieve the anticipated merger with Westar:						
Operating expense, pre-tax [a]	31.8	34.2	—	0.21	0.22	—
Financing, pre-tax [b]	85.5	35.9	—	0.55	0.24	—
Mark-to-market impacts of interest rate swaps, pre-tax [c]	(12.1)	(79.3)	—	(0.08)	(0.51)	—
Interest income, pre-tax [d]	(22.8)	(3.2)	—	(0.15)	(0.02)	—
Loss on Series B Preferred Stock dividend make-whole provisions, pre-tax [e]	124.8	—	—	0.80	—	—
Loss on extinguishment of debt, pre-tax [f]	82.8	—	—	0.53	—	—
Write-off of Series A deferred offering expenses, pre-tax [g]	15.0	—	—	0.10	—	—
Income tax expense (benefit) [h]	(59.7)	9.5	—	(0.37)	0.06	—
Preferred stock [i]	37.3	15.4	—	0.24	0.10	—
Impact of October 2016 share issuance [j]	N/A	N/A	N/A	(0.26)	0.15	—
Impact of U.S. federal income tax reform:						
Income tax expense [k]	130.3	—	—	0.84	—	—
Adjusted earnings (non-GAAP)	$ 269.4	$ 286.0	$ 211.4	$ 1.74	$ 1.85	$ 1.37
Average Shares Outstanding						
Shares used in calculating diluted earnings (loss) per common share				215.5	169.8	154.8
Adjustment for October 2016 share issuance [j]				(60.5)	(14.9)	—
Shares used in calculating adjusted earnings per share (non-GAAP)				155.0	154.9	154.8

[a] Reflects legal, advisory and consulting fees and certain severance expenses and are included in Costs to achieve the anticipated merger with Westar on the consolidated statements of comprehensive income (loss).

[b] Reflects fees for a bridge term loan facility and interest on Great Plains Energy's $4.3 billion senior notes and are included in Interest charges on the consolidated statements of comprehensive income (loss).

[c] Reflects the mark-to-market impacts of interest rate swaps and is included in Interest charges and Non-operating income on the consolidated statements of comprehensive income (loss).

[d] Reflects interest income earned on the proceeds from Great Plains Energy's October 2016 equity offerings and March 2017 issuance of $4.3 billion senior notes and is included in Non-operating income on the consolidated statements of comprehensive income (loss).

[e] Reflects the loss on the settlement of the Series B Preferred Stock dividend make-whole provisions and is included within Loss on Series B Preferred Stock dividend make-whole provisions on the consolidated statements of comprehensive income (loss).

[f] Reflects the loss on extinguishment of debt due to Great Plains Energy's redemption of its $4.3 billion senior notes and is included within Loss on extinguishment of debt on the consolidated statements of comprehensive income (loss).

[g] Reflects the write-off of deferred offering fees as a result of the termination of the stock purchase agreement for $750 million of 7.25% Mandatory Convertible Preferred Stock, Series A (Series A Preferred Stock) and is included within Non-operating expenses on the consolidated statements of comprehensive income (loss).

[h] Reflects an income tax effect calculated at a 38.9% statutory rate, with the exception of certain non-deductible legal and financing fees.

[i] Reflects reductions to earnings available for common shareholders related to preferred stock dividend requirements for Great Plains Energy's Series B Preferred Stock and redemption premiums associated with Series B Preferred Stock and cumulative preferred stock and are included in Preferred stock dividend requirements and redemption premium on the consolidated statements of comprehensive income (loss).

[j] Reflects the average share impact of Great Plains Energy's issuance of 60.5 million shares of common stock in October 2016.

[k] Reflects income tax expense associated with the revaluation of deferred income taxes and other initial impacts resulting from the enactment of U.S. federal income tax reform.

Regulatory Proceedings
See Note 6 to the consolidated financial statements for information regarding regulatory proceedings.

Impact of Recently Issued Accounting Standards
See Note 1 to the consolidated financial statements for information regarding the impact of recently issued accounting standards.

Wolf Creek Refueling Outage
Wolf Creek's latest refueling outage began on September 10, 2016 and ended on November 21, 2016. Wolf Creek's next refueling outage is planned to begin in March of 2018.

ENVIRONMENTAL MATTERS

See Note 15 to the consolidated financial statements for information regarding environmental matters.

RELATED PARTY TRANSACTIONS

See Note 18 to the consolidated financial statements for information regarding related party transactions.

CRITICAL ACCOUNTING POLICIES

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect reported amounts and related disclosures. Management considers an accounting estimate to be critical if it requires assumptions to be made that were uncertain at the time the estimate was made and changes in the estimate or different estimates that could have been used could have a material impact on Great Plains Energy's results of operations and financial position. Management has identified the following accounting policies as critical to the understanding of Great Plains Energy's results of operations and financial position. Management has discussed the development and selection of these critical accounting policies with the Audit Committee of the Great Plains Energy Board of Directors.

Pensions
Great Plains Energy incurs significant costs in providing non-contributory defined pension benefits. The costs are measured using actuarial valuations that are dependent upon numerous factors derived from actual plan experience and assumptions of future plan experience.

Pension costs are impacted by actual employee demographics (including age, life expectancies, compensation levels and employment periods), earnings on plan assets, the level of contributions made to the plan, and plan amendments. In addition, pension costs are also affected by changes in key actuarial assumptions, including anticipated rates of return on plan assets and the discount rates used in determining the projected benefit obligation and pension costs.

The assumed rate of return on plan assets was developed based on the weighted-average of long-term returns forecast for the expected portfolio mix of investments held by the plan. The assumed discount rate was selected based on the prevailing market rate of fixed income debt instruments with maturities matching the expected timing of the benefit obligation. These assumptions, updated annually at the measurement date, are based on management's best estimates and judgment; however, material changes may occur if these assumptions differ from actual events. See Note 9 to the consolidated financial statements for information regarding the assumptions used to determine benefit obligations and net costs.

The following table reflects the sensitivities associated with a 0.5% increase or a 0.5% decrease in key actuarial assumptions. Each sensitivity reflects the impact of the change based on a change in that assumption only.

Actuarial assumption	Change in Assumption	Impact on Projected Benefit Obligation	Impact on 2017 Pension Expense
		(millions)	
Discount rate	0.5% increase	$ (97.4)	$ (6.3)
Rate of return on plan assets	0.5% increase	—	(3.7)
Discount rate	0.5% decrease	110.1	7.0
Rate of return on plan assets	0.5% decrease	—	3.7

Pension expense for KCP&L and GMO is recorded in accordance with rate orders from the MPSC and KCC. The orders allow the difference between pension costs under GAAP and pension costs for ratemaking to be recorded as a regulatory asset or liability with future ratemaking recovery or refunds, as appropriate.

In 2017, Great Plains Energy's pension expense was $113.2 million under GAAP and $99.4 million for ratemaking. The impact on 2017 pension expense in the table above reflects the impact on GAAP pension costs. Under the Companies' rate agreements, any increase or decrease in GAAP pension expense would be deferred in a regulatory asset or liability for future ratemaking treatment. See Note 9 to the consolidated financial statements for additional information regarding the accounting for pensions.

Market conditions and interest rates significantly affect the future assets and liabilities of the plan. It is difficult to predict future pension costs, changes in pension liability and cash funding requirements due to the inherent uncertainty of market conditions.

Regulatory Assets and Liabilities
The Company has recorded assets and liabilities on its consolidated balance sheets resulting from the effects of the ratemaking process, which would not otherwise be recorded under GAAP. Regulatory assets represent incurred costs that are probable of recovery from future revenues. Regulatory liabilities represent future reductions in revenues or refunds to customers.

Management regularly assesses whether regulatory assets and liabilities are probable of future recovery or refund by considering factors such as decisions by the MPSC, KCC or FERC in Electric Utility's rate case filings; decisions in other regulatory proceedings, including decisions related to other companies that establish precedent on matters applicable to Electric Utility; and changes in laws and regulations. If recovery or refund of regulatory assets or liabilities is not approved by regulators or is no longer deemed probable, these regulatory assets or liabilities are recognized in the current period results of operations. Electric Utility's continued ability to meet the criteria for recording regulatory assets and liabilities may be affected in the future by restructuring and deregulation in the electric industry or changes in accounting rules. In the event that the criteria no longer applied to all or a portion of Electric Utility's operations, the related regulatory assets and liabilities would be written off unless an appropriate regulatory recovery mechanism were provided. Additionally, these factors could result in an impairment on utility plant assets. See Note 6 to the consolidated financial statements for additional information.

Impairments of Assets, Intangible Assets and Goodwill
Long-lived assets and intangible assets subject to amortization are required to be reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable as prescribed under GAAP.

Accounting rules require goodwill to be tested for impairment annually and when an event occurs indicating the possibility that an impairment exists. The goodwill impairment test consists of comparing the fair value of a reporting unit to its carrying amount, including goodwill, to identify potential impairment. In the event that the carrying amount exceeds the fair value of the reporting unit, an impairment loss is recognized for the difference between the carrying amount of the reporting unit and its fair value. Great Plains Energy's regulated electric utility operations are considered one reporting unit for assessment of impairment, as they are included within the same operating segment and have similar economic characteristics.

The annual impairment test for the $169.0 million of GMO acquisition goodwill was conducted on September 1, 2017. Fair value of the reporting unit substantially exceeded the carrying amount, including goodwill; therefore, there was no impairment of goodwill.

The determination of fair value of the reporting unit consisted of two valuation techniques: an income approach consisting of a discounted cash flow analysis and a market approach consisting of a determination of reporting unit invested capital using market multiples derived from the historical revenue, earnings before interest, income taxes, depreciation and amortization, net utility asset values and market prices of stock of peer companies. The results of the two techniques were evaluated and weighted to determine a point within the range that management considered representative of fair value for the reporting unit, which involves a significant amount of management judgment.

The discounted cash flow analysis is most significantly impacted by two assumptions: estimated future cash flows and the discount rate applied to those cash flows. Management determined the appropriate discount rate to be based on the reporting unit's weighted average cost of capital (WACC). The WACC takes into account both the return on equity authorized by the MPSC and KCC and after-tax cost of debt. Estimated future cash flows are based on Great Plains Energy's internal business plan, which assumes the occurrence of certain events in the future, such as the outcome of future rate filings, future approved rates of return on equity, anticipated earnings/returns related to future capital investments, continued recovery of cost of service and the renewal of certain contracts. Management also makes assumptions regarding the run rate of operations, maintenance and general and administrative costs based on the expected outcome of the aforementioned events. Should the actual outcome of some or all of these assumptions differ significantly from the current assumptions, revisions to current cash flow assumptions could cause the fair value of Great Plains Energy's reporting unit under the income approach to be significantly different in future periods and could result in a future impairment charge to goodwill.

The market approach analysis is most significantly impacted by management's selection of relevant peer companies as well as the determination of an appropriate control premium to be added to the calculated invested capital of the reporting unit, as control premiums associated with a controlling interest are not reflected in the quoted market price of a single share of stock. Management determined an appropriate control premium by using an average of control premiums for recent acquisitions in the industry. Changes in results of peer companies, selection of different peer companies and future acquisitions with significantly different control premiums could result in a significantly different fair value of Great Plains Energy's reporting unit.

Income Taxes

Income taxes are accounted for using the asset/liability approach. Deferred tax assets and liabilities are determined based on the temporary differences between the financial reporting and tax bases of assets and liabilities, applying enacted statutory tax rates in effect for the year in which the differences are expected to reverse. Deferred investment tax credits are amortized ratably over the life of the related property. Deferred tax assets are also recorded for net operating losses, capital losses and tax credit carryforwards. The Company is required to estimate the amount of taxes payable or refundable for the current year and the deferred tax liabilities and assets for future tax consequences of events reflected in the Company's consolidated financial statements or tax returns. Actual results could differ from these estimates for a variety of reasons including changes in income tax laws, enacted tax rates and results of audits by taxing authorities. This process also requires management to make assessments regarding the timing and probability of the ultimate tax impact from which actual results may differ. The Company records valuation allowances on deferred tax assets if it is determined that it is more likely than not that the asset will not be realized. See Note 21 to the consolidated financial statements for additional information.

GREAT PLAINS ENERGY RESULTS OF OPERATIONS

The following table summarizes Great Plains Energy's comparative results of operations.

	2017	2016	2015
		(millions)	
Operating revenues	$ 2,708.2	$ 2,676.0	$ 2,502.2
Fuel and purchased power	(608.6)	(590.1)	(608.7)
Transmission	(105.7)	(84.8)	(89.1)
Other operating expenses	(987.4)	(1,003.2)	(943.9)
Costs to achieve the anticipated merger with Westar	(31.8)	(34.2)	—
Depreciation and amortization	(371.1)	(344.8)	(330.4)
Operating income	603.6	618.9	530.1
Non-operating income and expenses	19.3	2.8	3.7
Loss on Series B Preferred Stock dividend make-whole provisions	(124.8)	—	—
Loss on extinguishment of debt	(82.8)	—	—
Interest charges	(290.7)	(161.5)	(199.3)
Income tax expense	(233.3)	(172.2)	(122.7)
Income from equity investments	2.5	2.0	1.2
Net income (loss)	(106.2)	290.0	213.0
Preferred dividends and redemption premium	(37.3)	(16.5)	(1.6)
Earnings (loss) available for common shareholders	$ (143.5)	$ 273.5	$ 211.4
Reconciliation of gross margin to operating revenues:			
Operating revenues	$ 2,708.2	$ 2,676.0	$ 2,502.2
Fuel and purchased power	(608.6)	(590.1)	(608.7)
Transmission	(105.7)	(84.8)	(89.1)
Gross margin [(a)]	$ 1,993.9	$ 2,001.1	$ 1,804.4

[(a)] Gross margin is a non-GAAP financial measure. See explanation of gross margin below.

2017 Compared to 2016

Electric Utility Segment

Electric Utility's net income decreased $35.2 million in 2017 compared to 2016 primarily due to:

- a $7.2 million decrease in gross margin driven by cooler weather and a performance incentive for energy efficiency programs under the Missouri Energy Efficiency Investment Act (MEEIA), primarily recognized in 2016; partially offset by an increase in weather-normalized retail demand, an increase in the recovery of program costs for energy efficiency programs under MEEIA, favorable arbitration and insurance settlements in 2017 and an increase in other margin items;
- an $8.2 million decrease in other operating expense primarily driven by a decrease in plant operating and maintenance expense and a decrease in injuries and damages expense primarily due to settled litigation; partially offset by an increase in program costs for energy efficiency programs under MEEIA;
- a $26.3 million increase in depreciation and amortization expense primarily driven by capital additions; and
- a $5.1 million increase in income tax expense primarily driven by the revaluation of KCP&L's and GMO's deferred income taxes not included in rate base as a result of the enactment of U.S. federal income tax reform in December 2017 and decreased wind production tax credits in 2017; partially offset by decreased pre-tax income.

Corporate and Other Activities

Great Plains Energy's corporate and other activities net loss increased $381.8 million in 2017 compared to 2016 primarily due to:

- $7.5 million of other operating expenses for the settlement of litigation at MPS Merchant in 2016;
- a $2.3 million decrease in operating expenses for costs to achieve the anticipated merger with Westar;
- a $130.8 million increase in interest charges due to:
    - an $81.2 million decrease in the mark-to-market gain on deal contingent interest rate swaps entered into in June 2016 to hedge against interest rate fluctuations prior to Great Plains Energy's issuance of $4.3 billion senior notes in March 2017; and
    - a $49.6 million increase in costs incurred to finance the acquisition of Westar under the Original Merger Agreement including $59.1 million of interest on Great Plains Energy's $4.3 billion senior notes issued in March 2017 and redeemed in July 2017 and a decrease of $9.2 million of fees and expenses for a bridge term loan facility;
- a $33.6 million increase in non-operating income due to $14.0 million of mark-to-market gains on deal contingent interest rate swaps and an increase of $19.6 million of interest income earned on increased cash and cash equivalents at Great Plains Energy in 2017 related to the proceeds from Great Plains Energy's October 2016 common stock and Series B Preferred Stock offerings and March 2017 issuance of $4.3 billion of senior notes;
- a $15.0 million increase in non-operating expenses due to the write-off of previously deferred offering fees as a result of the termination of the stock purchase agreement for $750 million of Series A Preferred Stock between Great Plains Energy and OCM Credit Portfolio LP (OMERS) in July 2017;
- a $124.8 million loss on the settlement of the Series B Preferred Stock dividend make-whole provisions in connection with the redemption of Great Plains Energy's Series B Preferred Stock in August 2017;
- an $82.8 million loss on extinguishment of debt due to Great Plains Energy's redemption of its $4.3 billion senior notes in July 2017;
- a $66.2 million increase in income tax expense related to these items;
- a $21.9 million increase in reductions to earnings available for common shareholders primarily due to preferred stock dividend requirements and the redemption premium for Great Plains Energy's Series B Preferred Stock issued in October 2016 and redeemed in August 2017; and
- a $119.2 million increase in income tax expense due to the enactment of U.S. federal income tax reform in December 2017, consisting of $110.1 million related to the revaluation of GMO's non-regulated deferred income tax assets and $9.1 million of income tax expense related to the reassessment of the valuation allowance needed for the realization of refundable AMT credits and state net operating loss (NOL) carryforwards.

2016 Compared to 2015

Electric Utility Segment

Electric Utility's net income increased $68.3 million in 2016 compared to 2015 primarily due to:

- a $196.7 million increase in gross margin driven by new retail rates and cost recovery mechanisms, warmer weather and an increase in the recovery of program costs and throughput disincentive as well as a performance incentive for energy efficiency programs under MEEIA, partially offset by a decrease in weather-normalized retail demand;
- a $50.0 million increase in other operating expenses driven by an increase in pension expense, an increase in program costs for energy efficiency programs under MEEIA, an increase in plant operating and maintenance expense, an increase in injuries and damages expense and an increase in general taxes driven by higher property taxes and higher gross receipts taxes due to an increase in retail revenues;
- $15.9 million of operating expenses for costs to achieve the anticipated merger with Westar;

- a $14.4 million increase in depreciation and amortization expense driven by capital additions;
- a $5.2 million increase in interest charges primarily due to an increase in interest expense in 2016 related to KCP&L's issuance of $350 million of 3.65% Senior Notes in August 2015; partially offset by a decrease in interest expense due to KCP&L's purchase in lieu of redemption of its $50.0 million and $21.9 million Environmental Improvement Revenue Refunding (EIRR) Series 2005 bonds in September 2015; and
- a $43.5 million increase in income tax expense driven by an increase in pre-tax income.

Corporate and Other Activities
Great Plains Energy's corporate and other activities net loss increased $6.2 million in 2016 compared to 2015 primarily due to:

- $7.5 million of other operating expenses for the settlement of litigation at MPS Merchant in 2016;
- $18.3 million of operating expenses for costs to achieve the anticipated merger with Westar;
- $35.9 million of interest charges for fees incurred for a bridge term loan facility;
- a $79.3 million mark-to-market gain on interest rate swaps entered into in June 2016 to hedge against interest rate fluctuations on future issuances of long-term debt expected to be issued to finance a portion of the cash consideration for the acquisition of Westar under the Original Merger Agreement;
- $3.2 million of interest income earned on the proceeds from Great Plains Energy's October 2016 common stock and depositary share offerings;
- $12.7 million of income tax expense related to these items; and
- $15.4 million of reductions to earnings available for common shareholders consisting of $14.8 million of dividends on Great Plains Energy's Series B Preferred Stock issued in October 2016 and $0.6 million related to the redemption of Great Plains Energy's cumulative preferred stock in August 2016.

Gross Margin
Gross margin is a financial measure that is not calculated in accordance with GAAP. Gross margin, as used by Great Plains Energy and KCP&L, is defined as operating revenues less fuel and purchased power and transmission. Expenses for fuel and purchased power and certain transmission costs, offset by wholesale sales margin, are subject to recovery through cost adjustment mechanisms. As a result, operating revenues increase or decrease in relation to a significant portion of these expenses. Management believes that gross margin provides a meaningful basis for evaluating Electric Utility's operations across periods because gross margin excludes the revenue effect of fluctuations in these expenses. Gross margin is used internally to measure performance against budget and in reports for management and the Great Plains Energy Board. The Companies' definition of gross margin may differ from similar terms used by other companies.

ELECTRIC UTILITY RESULTS OF OPERATIONS

The following table summarizes Electric Utility's results of operations.

	2017	2016	2015
		(millions)	
Operating revenues	$ 2,708.2	$ 2,676.0	$ 2,502.2
Fuel and purchased power	(608.6)	(590.1)	(608.7)
Transmission	(105.7)	(84.8)	(89.1)
Other operating expenses	(982.0)	(990.2)	(940.2)
Costs to achieve the anticipated merger with Westar	(15.7)	(15.9)	—
Depreciation and amortization	(371.1)	(344.8)	(330.4)
Operating income	625.1	650.2	533.8
Non-operating income and expenses	(1.9)	2.3	1.7
Interest charges	(196.9)	(196.1)	(190.9)
Income tax expense	(169.4)	(164.3)	(120.8)
Net income	$ 256.9	$ 292.1	$ 223.8
Reconciliation of gross margin to operating revenue:			
Operating revenues	$ 2,708.2	$ 2,676.0	$ 2,502.2
Fuel and purchased power	(608.6)	(590.1)	(608.7)
Transmission	(105.7)	(84.8)	(89.1)
Gross margin [(a)]	$ 1,993.9	$ 2,001.1	$ 1,804.4

[(a)] Gross margin is a non-GAAP financial measure. See explanation of gross margin under Great Plains Energy's Results of Operations.

Electric Utility Gross Margin and MWh Sales

The following tables summarize Electric Utility's gross margin and MWhs sold.

Gross Margin [(a)]	2017	% Change[(c)]	2016	% Change[(c)]	2015
Retail revenues			(millions)		
Residential	$ 1,088.5	—	$ 1,092.5	9	$ 1,006.2
Commercial	1,092.6	2	1,066.0	6	1,001.0
Industrial	238.3	4	229.6	3	222.3
Other retail revenues	18.7	(10)	20.9	3	20.4
Provision for rate refund	10.7	N/M	(9.6)	N/M	—
Energy efficiency (MEEIA)[(b)]	66.4	(17)	80.0	55	51.5
Total retail	2,515.2	1	2,479.4	8	2,301.4
Wholesale revenues	131.8	(7)	142.0	(3)	147.1
Other revenues	61.2	12	54.6	2	53.7
Operating revenues	2,708.2	1	2,676.0	7	2,502.2
Fuel and purchased power	(608.6)	3	(590.1)	(3)	(608.7)
Transmission	(105.7)	25	(84.8)	(5)	(89.1)
Gross margin	$ 1,993.9	—	$ 2,001.1	11	$ 1,804.4

[(a)] Gross margin is a non-GAAP financial measure. See explanation of gross margin under Great Plains Energy's Results of Operations.
[(b)] Consists of recovery of program costs of $55.0 million, $49.3 million and $42.9 million for 2017, 2016 and 2015, respectively, that have a direct offset in utility operating and maintenance expenses, recovery of throughput disincentive of $11.2 million, $15.1 million and $8.6 million for 2017, 2016 and 2015, respectively, and a performance incentive of $0.2 million and $15.6 million for 2017 and 2016, respectively.
[(c)] N/M - not meaningful

MWh Sales	2017	% Change	2016	% Change	2015
Retail MWh sales			(thousands)		
Residential	8,564	(2)	8,774	2	8,585
Commercial	10,695	(1)	10,796	—	10,777
Industrial	3,105	(1)	3,149	(1)	3,191
Other retail MWh sales	102	(11)	115	(1)	116
Total retail	22,466	(2)	22,834	1	22,669
Wholesale MWh sales	7,241	3	7,063	9	6,512
Total MWh sales	29,707	(1)	29,897	3	29,181

Electric Utility's residential customers' usage is significantly affected by weather. Bulk power sales, the major component of wholesale sales, vary with system requirements, generating unit availability, transmission availability, fuel costs, and requirements of other electric systems. Electric Utility's revenues contain certain recovery mechanisms as follows:

- KCP&L's Kansas retail rates contain an Energy Cost Adjustment (ECA) tariff. The ECA tariff reflects the projected annual amounts of fuel, purchased power, emission allowances and asset-based off-system sales margin. These projected amounts are subject to quarterly re-forecasts. Any difference between the ECA revenue collected and the actual ECA amounts for a given year (which may be positive or negative) is recorded either as a reduction of fuel and purchased power expense (for under-recoveries) or a reduction of retail revenues (for over-recoveries) and deferred as a regulatory asset or liability to be recovered from or refunded to Kansas electric retail customers over twelve months beginning April 1 of the succeeding year.
- KCP&L's Kansas retail rates contain a Transmission Delivery Charge (TDC) rider. The TDC tariff reflects a mixture of historical and projected costs related to transmission service, certain RTO fees, transmission rate base, and transmission operating and maintenance expense. These costs are subject to an annual true-up with a twelve month recovery period. The TDC true-up is recorded either as a reduction of transmission expense (for under-recoveries) or a reduction of retail revenues (for over-recoveries) and deferred as a regulatory asset or liability to be recovered from or refunded to KCP&L's Kansas electric retail customers. The TDC became effective in conjunction with new retail rates on October 1, 2015.
- KCP&L's Missouri retail rates contain a Fuel Adjustment Clause (FAC) tariff under which 95% of the difference between actual fuel cost, purchased power costs, certain transmission costs and off-system sales margin and the amount provided in base rates for these costs is passed along to KCP&L's customers. The FAC cycle consists of an accumulation period of six months beginning in January and July with FAC rate approval requested every six months for a twelve month recovery period. The FAC is recorded either as a reduction of fuel and purchased power expense (for under-recoveries) or a reduction of retail revenues (for over-recoveries) and deferred as a regulatory asset or liability to be recovered from or refunded to KCP&L's electric retail customers. The FAC became effective in conjunction with new retail rates on September 29, 2015.
- GMO's electric retail rates contain a FAC tariff under which 95% of the difference between actual fuel cost, purchased power costs, certain transmission costs and off-system sales margin and the amount provided in base rates for these costs is passed along to GMO's customers. The FAC cycle consists of an accumulation period of six months beginning in June and December with FAC rate approval requested every six months for a twelve month recovery period. The FAC is recorded either as a reduction of fuel and purchased power expense (for under-recoveries) or a reduction of retail revenues (for over-recoveries) and deferred as a regulatory asset or liability to be recovered from or refunded to GMO's electric retail customers.
- GMO's steam rates contain a Quarterly Cost Adjustment (QCA) under which 85% of the difference between actual fuel costs and base fuel costs is passed along to GMO's steam customers. The QCA is recorded either as a reduction of fuel and purchased power expense (for under-recoveries) or a reduction of retail revenues (for over-recoveries) and deferred as a regulatory asset or liability to be recovered from or refunded to GMO's steam customers.

Both KCP&L and GMO offer energy efficiency and demand side management programs to their Missouri retail customers under MEEIA and recover program costs, throughput disincentive and as applicable, certain performance incentives in retail rates. KCP&L and GMO recover these items through a rider mechanism. For program costs, the difference between the amount collected and actual program costs is recorded either as a reduction to utility operating and maintenance expense (for under-recoveries) or a reduction to retail revenues (for over-recoveries) and is deferred as a regulatory asset or liability to be recovered from or refunded to customers. For throughput disincentive, the difference between the amount collected and the actual throughput disincentive is recorded as an increase to or reduction of retail revenues and is deferred as a regulatory asset or liability to be recovered from or refunded to customers. The performance incentive is recorded as an increase to retail revenues and a receivable to be recovered from customers.

Electric Utility's gross margin decreased $7.2 million in 2017 compared to 2016 driven by:

- an estimated $53 million decrease due to cooler weather driven by a 16% decrease in cooling degree days (CDD);
- a $15.4 million decrease in MEEIA performance incentive related to the achievement of certain energy savings levels in the first cycle of KCP&L's and GMO's MEEIA programs, which was primarily recognized in 2016;
- an estimated $33 million increase due to weather-normalized retail demand;
- a $5.7 million increase for recovery of program costs for energy efficiency programs under MEEIA, which have a direct offset in utility operating and maintenance expense;
- $6.3 million of favorable arbitration and insurance settlements in 2017 that did not pass through KCP&L's fuel recovery mechanism in Missouri; and
- an estimated $16 million increase in other margin items.

Electric Utility's gross margin increased $196.7 million in 2016 compared to 2015 primarily driven by:

- an estimated $111 million increase due to new retail rates and an estimated $37 million increase due to new cost recovery mechanisms for KCP&L in Missouri effective September 29, 2015, and in Kansas effective October 1, 2015;
- an estimated $38 million increase due to warmer weather with a 16% increase in CDD in 2016;
- a $6.4 million increase for recovery of program costs for energy efficiency programs under MEEIA, which have a direct offset in utility operating and maintenance expense;
- a $6.5 million increase in MEEIA throughput disincentive;
- a $15.6 million MEEIA performance incentive recognized in 2016 related to the achievement of certain energy savings levels in the first cycle of KCP&L's and GMO's MEEIA programs; and
- an estimated $9 million decrease due to a decrease in weather-normalized retail demand.

The following table provides CDD and heating degree days (HDD) for the last three years at the Kansas City International Airport. CDD and HDD are used to reflect the demand for energy to cool or heat homes and buildings.

	2017	**% Change**	**2016**	**% Change**	**2015**
CDD	1,325	(16)	1,585	16	1,370
HDD	4,381	2	4,296	(6)	4,578

Electric Utility Other Operating Expenses ***(including utility operating and maintenance expenses, general taxes and other)***
Electric Utility's other operating expenses decreased $8.2 million in 2017 compared to 2016 primarily driven by:

- a $6.2 million decrease in plant operating and maintenance expense;
- a $10.5 million decrease in injuries and damages expense primarily due to settled litigation in 2017 in which actual losses were less than estimated; and
- a $5.7 million increase in program costs for energy efficiency programs under MEEIA, which have a direct offset in revenue.

Electric Utility's other operating expenses increased $50.0 million in 2016 compared to 2015 primarily driven by:

- a $4.8 million increase in pension expense corresponding to the resetting of pension expense trackers with the effective date of new retail rates;
- a $6.4 million increase in program costs for energy efficiency programs under MEEIA, which have a direct offset in revenue;
- a $4.9 million increase in plant operating and maintenance expense;
- a $7.9 million increase in injuries and damages expense primarily due to an increase in estimated losses from an unfavorable judgment in ongoing litigation; and
- a $13.7 million increase in general taxes driven by higher property taxes and higher gross receipts taxes due to an increase in retail revenues.

Electric Utility Depreciation and Amortization
Electric Utility's depreciation and amortization expense increased $26.3 million and $14.4 million in 2017 compared to 2016 and 2016 compared to 2015, respectively, primarily due to capital additions.

Electric Utility Interest Charges
Electric Utility's interest charges increased $5.2 million in 2016 compared to 2015 primarily due to a $7.9 million increase in interest expense related to KCP&L's issuance of $350 million of 3.65% Senior Notes in August 2015; partially offset by a $2.2 million decrease in interest expense due to KCP&L's purchase in lieu of redemption of its $50.0 million and $21.9 million EIRR Series 2005 bonds in September 2015.

Electric Utility Income Tax Expense
Electric Utility's income tax expense increased $5.1 million in 2017 compared to 2016 primarily due to an increase of $11.1 million related to the revaluation of KCP&L's and GMO's deferred income taxes not included in rate base as a result of the enactment of U.S. federal income tax reform in December 2017 and an increase of $4.5 million due to decreased wind production tax credits in 2017; partially offset by a decrease of $11.8 million due to decreased pre-tax income.

Electric Utility's income tax expense increased $43.5 million in 2016 compared to 2015 due to increased pre-tax income.

GREAT PLAINS ENERGY SIGNIFICANT BALANCE SHEET CHANGES
(December 31, 2017 compared to December 31, 2016)

- Great Plains Energy's cash and cash equivalents decreased $167.7 million primarily due to the redemption of Great Plains Energy's $4.3 billion senior notes for $4,400.1 million in July 2017, the redemption of Great Plains Energy's Series B Preferred Stock in August 2017 for $963.4 million and the maturity of Great Plains Energy's $100.0 million of 6.875% Senior Notes in September 2017; partially offset by the issuance of Great Plains Energy's $4.3 billion senior notes and the maturity of a $1.0 billion time deposit in March 2017.
- Great Plains Energy's time deposit decreased $1.0 billion due to its maturity in March 2017.

- Great Plains Energy's plant to be retired, net increased $143.6 million in connection with the expected retirement of GMO's Sibley No. 3 Unit. See Note 1 to the consolidated financial statements for additional information.
- Great Plains Energy's regulatory assets decreased $134.1 million and regulatory liabilities increased $796.4 million primarily due to an $868.3 million decrease in net deferred income tax liabilities due to the revaluation and restatement of deferred income tax assets and liabilities included in rate base and a tax gross-up adjustment for ratemaking purposes in December 2017 as a result of the change in corporate income tax rate from U.S. federal income tax reform. See Note 6 and Note 21 to the consolidated financial statements for additional information.
- Great Plains Energy's deferred income taxes decreased $708.0 million primarily due to the revaluation and restatement of deferred income tax assets and liabilities and a tax gross-up adjustment for ratemaking purposes in December 2017 as a result of the change in corporate income tax rate from U.S. federal income tax reform.
- Great Plains Energy's preference stock without par value decreased $836.2 million due to the redemption of Great Plains Energy's Series B Preferred Stock in August 2017.

CAPITAL REQUIREMENTS AND LIQUIDITY

Great Plains Energy operates through its subsidiaries and has no material assets other than the stock of its subsidiaries and cash and cash equivalents. Great Plains Energy's ability to make payments on its debt securities and its ability to pay dividends is dependent on its receipt of dividends or other distributions from its subsidiaries, proceeds from the issuance of its securities and borrowing under its revolving credit facility.

Great Plains Energy's capital requirements are principally comprised of debt maturities and Electric Utility's construction and other capital expenditures. These items as well as additional cash and capital requirements, including requirements related to the anticipated merger with Westar, are discussed below.

Great Plains Energy's liquid resources at December 31, 2017, consisted of $1.1 billion of cash and cash equivalents on hand and $856.4 million of available borrowing capacity from unused bank lines of credit and receivable sale agreements. The available borrowing capacity consisted of $188.0 million from Great Plains Energy's revolving credit facility, $429.8 million from KCP&L's credit facilities and $238.6 million from GMO's credit facilities. See Notes 4 and 11 to the consolidated financial statements for more information regarding the receivable sale agreements and revolving credit facilities, respectively. Generally, Great Plains Energy uses these liquid resources to meet its day-to-day cash flow requirements, and from time to time issues equity and/or long-term debt to repay short-term debt or increase cash balances.

The $1.1 billion of cash and cash equivalents on hand at December 31, 2017, is primarily the result of Great Plains Energy's common stock offering in October 2016, the proceeds of which were to be used to fund a portion of the cash consideration for the acquisition of Westar under the Original Merger Agreement. Great Plains Energy also expects to receive $140.6 million in proceeds from its deal contingent interest rate swaps upon the closing of the anticipated merger with Westar. Under the Amended Merger Agreement, Great Plains Energy is required to have not less than $1.25 billion in cash and cash equivalents on its balance sheet at the closing of the anticipated merger with Westar. It is expected that this excess cash will be returned to shareholders of the combined company through the repurchase of common stock over time after the closing of the anticipated merger.

Great Plains Energy intends to meet day-to-day cash flow requirements including interest payments, retirement of maturing debt, construction requirements, dividends and pension benefit plan funding requirements with a combination of internally generated funds and proceeds from short-term debt. From time to time, Great Plains Energy issues equity and/or long-term debt to repay short-term debt or increase cash balances. Great Plains Energy's intention to meet a portion of these requirements with internally generated funds may be impacted by the effect of inflation on operating expenses, the level of MWh sales, regulatory actions, compliance with environmental regulations and the availability of generating units. In addition, Great Plains Energy may issue equity, equity-linked securities and/or debt to finance growth.

Cash Flows from Operating Activities

Great Plains Energy generated positive cash flows from operating activities for the periods presented. The $26.5 million increase in cash flows from operating activities for Great Plains Energy in 2017 compared to 2016 was primarily driven by a $35.5 million decrease in the under recovery of costs subject to fuel recovery mechanisms partially offset by an increase in Great Plains Energy's pension funding contributions of $7.1 million. Other changes in working capital are detailed in Note 3 to the consolidated financial statements. The individual components of working capital vary with normal business cycles and operations.

The $30.9 million increase in cash flows from operating activities for Great Plains Energy in 2016 compared to 2015 was primarily driven by new retail rates for KCP&L and warmer weather.

Cash Flows from Investing Activities

Great Plains Energy's cash used for investing activities varies with the timing of utility capital expenditures and purchases of investments and nonutility property.

In 2017, Great Plains Energy received $1.0 billion for proceeds from the maturity of a time deposit.

In 2016, Great Plains Energy purchased a $1.0 billion time deposit with a portion of the proceeds from its October 2016 common stock and depositary share offerings.

Great Plains Energy's utility capital expenditures decreased $67.7 million in 2016 compared to 2015 primarily due to a decrease in cash utility capital expenditures related to infrastructure and system improvements.

Cash Flows from Financing Activities

Great Plains Energy's cash flows from financing activities in 2017 reflects gross proceeds of $4.6 billion from the issuance of Great Plains Energy's $4.3 billion senior notes in March 2017 and KCP&L's issuance of $300.0 million of 4.20% unsecured Senior Notes in June 2017; $38.3 million in issuance fees related to the issuance of senior notes; $4.7 billion of long-term debt repayments from the maturity of KCP&L's $250.0 million of 5.85% unsecured Senior Notes in June 2017, the redemption of Great Plains Energy's $4.3 billion senior notes and a $43.0 million redemption premium in July 2017, the maturity of KCP&L's $31.0 million secured Series 1992 EIRR in July 2017 and the maturity of Great Plains Energy's $100.0 million of 6.875% unsecured Senior Notes in September 2017; a $78.0 million increase in dividends paid in 2017 compared to 2016 primarily due to Great Plains Energy's October 2016 common stock and depositary share offerings; and the $963.4 million redemption of Series B Preferred Stock in August 2017.

Great Plains Energy's cash flows from financing activities in 2016 reflect gross proceeds of $1.6 billion from the issuance of 60.5 million shares of common stock at a public offering price of $26.45 per share and gross proceeds of $862.5 million from the issuance of 17.3 million depositary shares each representing a 1/20th interest in a share of Great Plains Energy's Series B Preferred Stock at $50 per depositary share. Great Plains Energy paid $40.1 million for the redemption of its 390,000 shares of cumulative preferred stock and $143.6 million in issuance fees related to common stock and depositary share issuances, establishing Great Plains Energy's bridge term loan facility and a payment to OMERS pursuant to a stock purchase agreement.

Impact of Credit Ratings on Liquidity

The ratings of Great Plains Energy's, KCP&L's and GMO's securities by the credit rating agencies impact their liquidity, including the cost of borrowings under their revolving credit agreements and in the capital markets. The Companies view maintenance of strong credit ratings as extremely important to their access to and cost of debt financing and to that end maintain an active and ongoing dialogue with the agencies with respect to results of operations, financial position and future prospects. While a decrease in these credit ratings would not cause any acceleration of Great Plains Energy's, KCP&L's or GMO's debt, it could increase interest charges under Great Plains Energy's, KCP&L's and GMO's revolving credit agreements. A decrease in credit ratings could also have, among other things, an adverse impact, which could be material, on Great Plains Energy's, KCP&L's and GMO's access to capital, the cost of funds, the ability to recover actual interest costs in state regulatory proceedings, the type and amounts of collateral required under supply agreements and Great Plains Energy's ability to provide credit support for its subsidiaries.

As of February 21, 2018, the major credit rating agencies rated Great Plains Energy's, KCP&L's and GMO's securities as detailed in the following table.

	Moody's Investors Service	S&P Global Ratings
Great Plains Energy		
Outlook	Stable	Positive
Corporate Credit Rating	-	BBB+
Senior Unsecured Debt	Baa2	BBB
KCP&L		
Outlook	Stable	Positive
Senior Secured Debt	A2	A
Senior Unsecured Debt	Baa1	BBB+
Commercial Paper	P-2	A-2
GMO		
Outlook	Stable	Positive
Senior Unsecured Debt	Baa2	BBB+
Commercial Paper	P-2	A-2

A securities rating is not a recommendation to buy, sell or hold securities and may be subject to revision or withdrawal at any time by the assigning rating agency.

Financing Authorization

Under stipulations with the MPSC and KCC, Great Plains Energy and KCP&L maintain common equity at not less than 30% and 35%, respectively, of total capitalization (including only the amount of short-term debt in excess of the amount of construction work in progress).

KCP&L's long-term financing activities are subject to the authorization of the MPSC. In May 2017, the MPSC authorized KCP&L to issue up to $350.0 million of long-term debt through December 31, 2017. At December 31, 2017, KCP&L had utilized $300.0 million of this authorization. In February 2018, the MPSC authorized KCP&L to issue up to $750.0 million of long-term debt through September 30, 2019, to replace the authorization which expired on December 31, 2017.

KCP&L's and GMO's short-term financing activities are subject to the authorization of FERC. In November 2016, FERC authorized KCP&L to have outstanding at any one time up to a total of $1.0 billion in short-term debt instruments through December 2018. At December 31, 2017, there was $832.5 million available under this authorization. In February 2016, FERC authorized GMO to have outstanding at any one time up to a total of $750.0 million in short-term debt instruments through March 2018. At December 31, 2017, there was $540.7 million available under this authorization. In December 2017, GMO filed a request with FERC to have outstanding at any one time up to $750.0 million in short-term debt instruments through March 2020.

KCP&L and GMO are also authorized by FERC to participate in the Great Plains Energy money pool, an internal financing arrangement in which funds may be lent on a short-term basis to KCP&L and GMO. At December 31, 2017, there were no outstanding payables under the money pool.

Significant Financing Activities

Great Plains Energy

Great Plains Energy has an effective shelf registration statement for the sale of unlimited amounts of securities with the SEC that became effective in March 2015 and expires in March 2018. Great Plains Energy does not expect to replace this shelf registration statement prior to the closing of the anticipated merger with Westar.

In March 2017, Great Plains Energy issued $4.3 billion of senior notes and as a result of the Amended Merger Agreement, redeemed the senior notes in July 2017. See Note 12 to the consolidated financial statements for more information on the redemption of the senior notes.

In August 2017, as a result of the Amended Merger Agreement, Great Plains Energy redeemed its Series B Preferred Stock. See Note 14 to the consolidated financial statements for more information on the redemption of the Series B Preferred Stock.

In September 2017, Great Plains Energy repaid its $100.0 million of 6.875% unsecured Senior Notes at maturity.

KCP&L

KCP&L has an effective shelf registration statement providing for the sale of unlimited amounts of notes and mortgage bonds with the SEC that was filed and became effective in March 2015 and expires in March 2018. Upon expiration of this registration statement, KCP&L intends to file a new shelf registration statement with the SEC providing for the sale of up to $1.1 billion in aggregate principal amount of notes and mortgage bonds.

In June 2017, KCP&L issued, at a discount, $300.0 million of 4.20% unsecured Senior Notes, maturing in 2047, with proceeds used to repay $250.0 million of 5.85% Senior Notes that matured in June 2017 and $31.0 million of secured Series 1992 EIRR bonds that matured in July 2017.

Debt Agreements

See Note 11 to the consolidated financial statements for information regarding revolving credit facilities.

Projected Utility Capital Expenditures

Great Plains Energy's cash utility capital expenditures, excluding Allowance for Funds Used During Construction (AFUDC) to finance construction, were $573.5 million, $609.4 million and $677.1 million in 2017, 2016 and 2015, respectively. Utility capital expenditures represent a significant portion of Great Plains Energy's capital requirements. Utility capital expenditures projected for the next five years include improvements to generating, distribution and transmission facilities, software upgrades and expenditures for environmental projects at coal-fired power plants. Great Plains Energy intends to meet these capital requirements with a combination of internally generated funds and proceeds from short-term and long-term debt.

Utility capital expenditures projected for the next five years, excluding AFUDC, are detailed in the following table. This utility capital expenditure plan is subject to continual review and change.

	2018	2019	2020	2021	2022
			(millions)		
Generating facilities	$ 165.8	$ 170.2	$ 151.4	$ 139.8	$ 151.7
Distribution and transmission facilities	246.7	256.6	245.7	284.7	235.2
General facilities	100.2	108.8	93.4	87.5	71.0
Nuclear fuel	21.4	24.7	43.8	25.4	24.8
Environmental	14.6	2.8	7.7	20.1	63.1
Total utility capital expenditures	$ 548.7	$ 563.1	$ 542.0	$ 557.5	$ 545.8

Pensions

The Company incurs significant costs in providing defined benefit plans for substantially all active and inactive employees of KCP&L and GMO and its 47% ownership share of WCNOC's defined benefit plans. Funding of the plans follows legal and regulatory requirements with funding equaling or exceeding the minimum requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA).

In 2017 and 2016, the Company contributed $76.9 million and $69.8 million to the pension plans, respectively, and expects to contribute $84.0 million in 2018 to satisfy ERISA funding requirements and the MPSC and KCC rate orders, the majority of which is expected to be paid by KCP&L. Additional contributions to the plans are expected beyond 2018 in amounts at least sufficient to meet the greater of ERISA or regulatory funding requirements; however, these amounts have not yet been determined.

Additionally, the Company provides post-retirement health and life insurance benefits for certain retired employees and expects to make benefit contributions of $4.6 million under the provisions of these plans in 2018, the majority of which is expected to be paid by KCP&L.

Management believes the Company has adequate access to capital resources through cash flows from operations or through existing lines of credit to support these funding requirements.

Supplemental Capital Requirements and Liquidity Information

The information in the following table is provided to summarize Great Plains Energy's cash obligations and commercial commitments.

Payment due by period	2018	2019	2020	2021	2022	After 2022	Total
Long-term debt				(millions)			
Principal	$ 351.1	$ 401.1	$ 1.1	$ 432.0	$ 287.5	$ 2,209.6	$ 3,682.4
Interest	170.3	144.9	130.5	121.9	99.0	1,180.7	1,847.3
Lease commitments							
Operating leases	12.1	9.3	9.7	9.7	9.5	101.0	151.3
Capital leases	0.4	0.4	0.4	0.4	0.4	2.7	4.7
Pension and other post-retirement plans	88.6	88.6	88.6	88.6	88.6	(a)	443.0
Purchase commitments							
Fuel	210.4	180.1	67.3	5.1	37.4	80.7	581.0
Power	47.3	47.3	47.3	47.4	47.6	414.6	651.5
Other	20.9	14.7	6.7	5.5	2.4	35.9	86.1
Total contractual commitments [a]	$ 901.1	$ 886.4	$ 351.6	$ 710.6	$ 572.4	$ 4,025.2	$ 7,447.3

[a] The Company expects to make contributions to the pension and other post-retirement plans beyond 2022 but the amounts are not yet determined. Amounts for years after 2018 are estimates based on information available in determining the amount for 2018. Actual amounts for years after 2018 could be significantly different than the estimated amounts in the table above.

Long-term debt includes current maturities. Long-term debt principal excludes $18.7 million of net discounts on senior notes and debt issuance costs. Variable rate interest obligations are based on rates as of December 31, 2017.

Lease commitments end in 2048. Operating lease commitments include railcars to serve jointly-owned generating units where KCP&L is the managing partner. Of the amounts included in the table above, KCP&L will be reimbursed by the other owners for approximately $1.2 million in 2018 and approximately $0.4 million per year from 2019 to 2025, for a total of $4.0 million.

The Company expects to contribute $88.6 million to the pension and other post-retirement plans in 2018, of which the majority is expected to be paid by KCP&L. Additional contributions to the plans are expected beyond 2022 in amounts at least sufficient to meet the greater of ERISA or regulatory funding requirements; however, these amounts have not yet been determined. Amounts for years after 2018 are estimates based on information available in determining the amount for 2018. Actual amounts for years after 2018 could be significantly different than the estimated amounts in the table above.

Fuel commitments consist of commitments for nuclear fuel, coal and coal transportation costs. Power commitments consist of commitments for renewable energy under power purchase agreements. Other represents individual commitments entered into in the ordinary course of business.

Great Plains Energy has other insignificant long-term liabilities recorded on its consolidated balance sheet at December 31, 2017, which do not have a definitive cash payout date and are not included in the table above.

Off-Balance Sheet Arrangements

In the ordinary course of business, Great Plains Energy and certain of its subsidiaries enter into various agreements providing financial or performance assurance to third parties on behalf of certain subsidiaries. Such agreements include, for example, guarantees and letters of credit. These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to a subsidiary on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiary's intended business purposes. The majority of these agreements guarantee the Company's own future performance, so a liability for the fair value of the obligation is not recorded.

At December 31, 2017, Great Plains Energy has provided $133.5 million of credit support for GMO as follows:

- Great Plains Energy direct guarantees to GMO counterparties totaling $38.0 million, which expire in 2018 and
- Great Plains Energy guarantees of GMO long-term debt totaling $95.5 million, which includes debt with maturity dates ranging from 2018 to 2023.

Great Plains Energy has also guaranteed GMO's commercial paper program. At December 31, 2017, GMO had $209.3 million commercial paper outstanding. None of the guaranteed obligations are subject to default or prepayment if GMO's credit ratings were downgraded.

At December 31, 2017, KCP&L had issued letters of credit totaling $5.2 million as credit support to certain counterparties that expire in 2018. KCP&L has also issued $148.1 million of letters of credit as credit support for its variable rate EIRR Bond Series 2007A and B that expire in 2018.

At December 31, 2017, GMO had issued letters of credit totaling $2.1 million as credit support to certain counterparties that expire in 2018.

KANSAS CITY POWER & LIGHT COMPANY

MANAGEMENT'S NARRATIVE ANALYSIS OF RESULTS OF OPERATIONS

The following table summarizes KCP&L's consolidated comparative results of operations.

	2017	2016
	(millions)	
Operating revenues	$ 1,890.7	$ 1,875.4
Fuel and purchased power	(412.1)	(372.7)
Transmission	(68.6)	(56.4)
Other operating expenses	(689.5)	(705.8)
Costs to achieve the anticipated merger with Westar	(10.5)	(10.9)
Depreciation and amortization	(266.3)	(247.5)
Operating income	443.7	482.1
Non-operating income and expenses	3.1	4.2
Interest charges	(138.8)	(139.4)
Income tax expense	(128.2)	(121.9)
Net income	$ 179.8	$ 225.0
Reconciliation of gross margin to operating revenues:		
Operating revenues	$ 1,890.7	$ 1,875.4
Fuel and purchased power	(412.1)	(372.7)
Transmission	(68.6)	(56.4)
Gross margin [(a)]	$ 1,410.0	$ 1,446.3

(a) Gross margin is a non-GAAP financial measure. See explanation of gross margin under Great Plains Energy's Results of Operations.

KCP&L Gross Margin and MWh Sales

The following table summarizes KCP&L's gross margin and MWhs sold.

	Revenues and Costs 2017	Revenues and Costs 2016	% Change	MWhs Sold 2017	MWhs Sold 2016	% Change
Retail revenues	(millions)			(thousands)		
Residential	$ 715.6	$ 713.0	—	5,182	5,330	(3)
Commercial	826.5	798.5	4	7,466	7,553	(1)
Industrial	157.7	147.4	7	1,815	1,839	(1)
Other retail revenues	11.1	13.1	(15)	72	83	(14)
Provision for rate refund	0.9	0.8	16	N/A	N/A	N/A
Energy efficiency (MEEIA)[(a)]	30.1	50.9	(41)	N/A	N/A	N/A
Total retail	1,741.9	1,723.7	1	14,535	14,805	(2)
Wholesale revenues	122.9	128.9	(5)	6,788	6,629	2
Other revenues	25.9	22.8	13	N/A	N/A	N/A
Operating revenues	1,890.7	1,875.4	1	21,323	21,434	(1)
Fuel and purchased power	(412.1)	(372.7)	11			
Transmission	(68.6)	(56.4)	22			
Gross margin [(b)]	$ 1,410.0	$ 1,446.3	(3)			

(a) Consists of recovery of program costs of $24.1 million and $31.0 million for 2017 and 2016, respectively, that have a direct offset in operating and maintenance expenses and recovery of throughput disincentive of $6.0 million and $9.5 million for 2017 and 2016, respectively, and a performance incentive of $10.4 million for 2016.

(b) Gross margin is a non-GAAP financial measure. See explanation of gross margin under Great Plains Energy's Results of Operations.

KCP&L's gross margin decreased $36.3 million in 2017 compared to 2016 primarily driven by:

- an estimated $42 million decrease due to cooler weather driven by a 16% decrease in CDD;
- a $6.9 million decrease for recovery of program costs for energy efficiency programs under MEEIA, which have a direct offset in utility operating and maintenance expense;
- a $10.4 million MEEIA performance incentive related to the achievement of certain energy savings levels in the first cycle of KCP&L's MEEIA program, which was recognized in 2016;
- $6.3 million of favorable arbitration and insurance settlements in 2017 that did not pass through KCP&L's fuel recovery mechanism in Missouri; and
- an estimated $14 million increase due to weather-normalized retail demand.

KCP&L Other Operating Expenses (*including utility operating and maintenance expenses, general taxes and other*)
KCP&L's other operating expenses decreased $16.3 million in 2017 compared to 2016 primarily driven by:

- a $6.9 million decrease in program costs for energy efficiency programs under MEEIA, which have a direct offset in revenue;
- a $3.7 million decrease in plant operating and maintenance expense; and
- a $10.6 million decrease in injuries and damages expense primarily due to settled litigation in 2017 in which actual losses were less than estimated.

KCP&L Depreciation and Amortization
KCP&L's depreciation and amortization expense increased $18.8 million in 2017 compared to 2016 primarily due to capital additions.

KCP&L Income Tax Expense
KCP&L's income tax expense increased $6.3 million in 2017 compared to 2016 primarily due to an increase of $16.5 million related to the revaluation of KCP&L's deferred income taxes not included in rate base as a result of the enactment of U.S. federal income tax reform in December 2017 and an increase of $4.5 million due to decreased wind production tax credits in 2017; partially offset by a decrease of $15.1 million due to decreased pre-tax income.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

In the ordinary course of business, Great Plains Energy and KCP&L face risks that are either non-financial or non-quantifiable. Such risks principally include business, legal, operational and credit risks and are not represented in the following analysis. See Item 1A Risk Factors and Item 7 MD&A for further discussion of risk factors.

Great Plains Energy and KCP&L are exposed to market risks associated with commodity price and supply, interest rates and equity prices. Management has established risk management policies and strategies to reduce the potentially adverse effects that the volatility of the markets may have on its operating results. During the ordinary course of business, under the direction and control of an internal commodity risk committee, Great Plains Energy's and KCP&L's hedging strategies are reviewed to determine the hedging approach deemed appropriate based upon the circumstances of each situation. Though management believes its risk management practices are effective, it is not possible to identify and eliminate all risk. Great Plains Energy and KCP&L could experience losses, which could have a material adverse effect on their results of operations or financial position, due to many factors, including unexpectedly large or rapid movements or disruptions in the energy markets, from regulatory-driven market rule changes and/or bankruptcy or non-performance of customers or counterparties, and/or failure of underlying transactions that have been hedged to materialize.

Hedging Strategies
Great Plains Energy and KCP&L, from time to time, utilize derivative instruments to execute risk management and hedging strategies. Derivative instruments, such as futures, forward contracts, swaps or options, derive their value

from underlying assets, indices, reference rates or a combination of these factors. These derivative instruments include negotiated contracts, which are referred to as over-the-counter derivatives, and instruments listed and traded on an exchange.

Interest Rate Risk
Great Plains Energy and KCP&L manage interest expense and short- and long-term liquidity through a combination of fixed and variable rate debt. Generally, the amount of each type of debt is managed through market issuance, but interest rate swap and cap agreements with highly rated financial institutions may also be used to achieve the desired combination. At December 31, 2017, 4% and 7%, respectively, of Great Plains Energy's and KCP&L's long-term debt was variable rate debt. Interest rates impact the fair value of long-term debt. A change in interest rates would impact Great Plains Energy and KCP&L to the extent they redeemed any of their outstanding long-term debt. Great Plains Energy's and KCP&L's book values of long-term debt were below fair value by 7% at December 31, 2017.

Great Plains Energy and KCP&L had $376.8 million and $167.5 million, respectively, of commercial paper outstanding at December 31, 2017. The principal amount of the commercial paper, which will vary during the year, drives Great Plains Energy's and KCP&L's commercial paper interest expense. Assuming $376.8 million and $167.5 million of commercial paper was outstanding for all of 2018 for Great Plains Energy and KCP&L, respectively, a hypothetical 10% increase in commercial paper rates would result in an increase in interest expense of $0.5 million for Great Plains Energy and $0.2 million for KCP&L in 2018. Assuming $376.8 million and $167.5 million of commercial paper was outstanding for all of 2018 for Great Plains Energy and KCP&L, respectively, a hypothetical 100 basis point increase in commercial paper rates would result in an increase in interest expense of $3.8 million for Great Plains Energy and $1.7 million for KCP&L in 2018.

Commodity Risk
Great Plains Energy and KCP&L engage in the wholesale and retail marketing of electricity and are exposed to risk associated with the price of electricity. Exposure to these risks is affected by a number of factors including the quantity and availability of fuel used for generation and the quantity of electricity customers consume. Customers' electricity usage could also vary from year to year based on the weather or other factors. Quantities of fossil fuel used for generation vary from year to year based on the availability, price and deliverability of a given fuel type as well as planned and unplanned outages at facilities that use fossil fuels.

KCP&L's wholesale operations include the physical delivery and marketing of power obtained through its generation capacity. KCP&L is required to maintain a minimum reserve margin of 12%. This net positive supply of capacity is maintained through KCP&L's generation assets, capacity agreements, power purchase agreements and peak demand reduction programs to protect KCP&L from the potential operational failure of one of its power generating units. KCP&L continually evaluates the need for additional risk mitigation measures in order to minimize its financial exposure to, among other things, spikes in wholesale power prices during periods of high demand.

KCP&L's sales include the sale of electricity to its retail customers and bulk power sales of electricity in the wholesale market. KCP&L is a member of SPP Consolidated Balancing Authority (CBA) and Integrated Marketplace (IM), which are largely responsible for the dispatch of member generating facilities and the resulting supply of energy to fulfill member load obligations. KCP&L's Kansas ECA allows for the recovery of increased fuel and purchased power costs from Kansas retail customers. KCP&L’s Missouri FAC allows for KCP&L Missouri retail electric rates to be adjusted based on 95% of the difference between actual fuel and purchased power costs and the amount of fuel and purchased power costs provided in base rates. Most of the change in market prices for fuel and purchased power is recovered through the ECA or FAC, which mitigates KCP&L’s commodity price exposure.

GMO is also a member of SPP’s CBA and IM. GMO has an FAC that allows GMO to adjust retail electric rates based on 95% of the difference between actual fuel and purchased power costs and the amount of fuel and purchased power costs provided in base rates. Most of the change in market prices for fuel and purchased power is recovered through the FAC, which mitigates GMO's commodity price exposure.

Credit Risk - MPS Merchant

MPS Merchant is exposed to credit risk. Credit risk is measured by the loss that would be recorded if counterparties failed to perform pursuant to the terms of the contractual obligations less the value of any collateral held. MPS Merchant's counterparties are not externally rated. Credit exposure to counterparties at December 31, 2017, was $4.5 million.

Investment Risk

KCP&L maintains trust funds, as required by the NRC, to fund its share of decommissioning the Wolf Creek nuclear power plant. As of December 31, 2017, these funds were invested primarily in domestic equity securities and fixed income securities and are reflected at fair value on KCP&L's balance sheets. The mix of securities is designed to provide returns to be used to fund decommissioning and to compensate for inflationary increases in decommissioning costs; however, the equity securities in the trusts are exposed to price fluctuations in equity markets and the value of fixed rate fixed income securities are exposed to changes in interest rates. A hypothetical increase in interest rates resulting in a hypothetical 10% decrease in the value of the fixed income securities would have resulted in a $7.2 million reduction in the value of the decommissioning trust funds at December 31, 2017. A hypothetical 10% decrease in equity prices would have resulted in an $18.2 million reduction in the fair value of the equity securities at December 31, 2017. KCP&L's exposure to investment risk associated with the decommissioning trust funds is in large part mitigated due to the fact that KCP&L is currently allowed to recover its decommissioning costs in its rates. If the actual return on trust assets is below the anticipated level, KCP&L could be responsible for the balance of funds required to decommission Wolf Creek; however, while there can be no assurances, management believes a rate increase would be allowed to recover decommissioning costs over the remaining life of the unit.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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Great Plains Energy Incorporated

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of Great Plains Energy Incorporated

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Great Plains Energy Incorporated and subsidiaries (the "Company") as of December 31, 2017 and 2016, and the related consolidated statements of comprehensive income (loss), shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2017, and the related notes and the financial statement schedules 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 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.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholder and the Board of Directors of Kansas City Power & Light Company

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Kansas City Power & Light Company and subsidiaries (the "Company") as of December 31, 2017 and 2016, the related consolidated statements of comprehensive income, common shareholder's equity, and cash flows, for each of the three years in the period ended December 31, 2017, and the related notes and the financial statement 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 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.

GREAT PLAINS ENERGY INCORPORATED

Consolidated Statements of Comprehensive Income (Loss)

Year Ended December 31	2017	2016	2015
Operating Revenues	(millions, except per share amounts)		
Electric revenues	$ 2,708.2	$ 2,676.0	$ 2,502.2
Operating Expenses			
Fuel and purchased power	608.6	590.1	608.7
Transmission	105.7	84.8	89.1
Utility operating and maintenance expenses	754.2	759.5	724.8
Costs to achieve the anticipated merger with Westar Energy, Inc.	31.8	34.2	—
Depreciation and amortization	371.1	344.8	330.4
General taxes	229.2	226.7	213.2
Other	4.0	17.0	5.9
Total	2,104.6	2,057.1	1,972.1
Operating income	603.6	618.9	530.1
Other Income (Expense)			
Non-operating income	50.7	17.1	11.7
Non-operating expenses	(31.4)	(14.3)	(8.0)
Loss on Series B Preferred Stock dividend make-whole provisions (Note 14)	(124.8)	—	—
Loss on extinguishment of debt (Note 12)	(82.8)	—	—
Total	(188.3)	2.8	3.7
Interest charges	(290.7)	(161.5)	(199.3)
Income before income tax expense and income from equity investments	124.6	460.2	334.5
Income tax expense	(233.3)	(172.2)	(122.7)
Income from equity investments, net of income taxes	2.5	2.0	1.2
Net income (loss)	(106.2)	290.0	213.0
Preferred stock dividend requirements and redemption premium	37.3	16.5	1.6
Earnings (loss) available for common shareholders	$ (143.5)	$ 273.5	$ 211.4
Average number of basic common shares outstanding	215.5	169.4	154.2
Average number of diluted common shares outstanding	215.5	169.8	154.8
Basic and diluted earnings (loss) per common share	$ (0.67)	$ 1.61	$ 1.37
Comprehensive Income (Loss)			
Net income (loss)	$ (106.2)	$ 290.0	$ 213.0
Other comprehensive income			
Derivative hedging activity			
Reclassification to expenses, net of tax	4.9	5.6	5.7
Derivative hedging activity, net of tax	4.9	5.6	5.7
Defined benefit pension plans			
Net gain (loss) arising during period	(0.7)	(1.1)	1.0
Income tax (expense) benefit	(0.2)	0.4	(0.4)
Net gain (loss) arising during period, net of tax	(0.9)	(0.7)	0.6
Amortization of net losses included in net periodic benefit costs, net of tax	0.4	0.5	0.4
Change in unrecognized pension expense, net of tax	(0.5)	(0.2)	1.0
Total other comprehensive income	4.4	5.4	6.7
Comprehensive income (loss)	$ (101.8)	$ 295.4	$ 219.7

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

GREAT PLAINS ENERGY INCORPORATED

Consolidated Balance Sheets

	December 31	
	2017	2016
ASSETS	(millions, except share amounts)	
Current Assets		
Cash and cash equivalents	**$ 1,125.4**	$ 1,293.1
Time deposit	**—**	1,000.0
Receivables, net	**151.7**	166.0
Accounts receivable pledged as collateral	**180.0**	172.4
Fuel inventories, at average cost	**103.2**	108.8
Materials and supplies, at average cost	**171.2**	162.2
Deferred refueling outage costs	**6.8**	22.3
Interest rate derivative instruments	**91.4**	79.3
Prepaid expenses and other assets	**33.4**	55.4
Total	**1,863.1**	3,059.5
Utility Plant, at Original Cost		
Electric	**13,674.1**	13,597.7
Less - accumulated depreciation	**5,224.0**	5,106.9
Net utility plant in service	**8,450.1**	8,490.8
Construction work in progress	**458.6**	403.9
Plant to be retired, net	**143.6**	—
Nuclear fuel, net of amortization of $204.2 and $172.1	**72.4**	62.0
Total	**9,124.7**	8,956.7
Investments and Other Assets		
Nuclear decommissioning trust fund	**258.4**	222.9
Regulatory assets	**913.9**	1,048.0
Goodwill	**169.0**	169.0
Other	**128.8**	113.9
Total	**1,470.1**	1,553.8
Total	**$ 12,457.9**	$ 13,570.0

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

GREAT PLAINS ENERGY INCORPORATED

Consolidated Balance Sheets

	December 31	
	2017	2016
LIABILITIES AND CAPITALIZATION	(millions, except share amounts)	
Current Liabilities		
Notes payable	**$ 11.0**	$ —
Collateralized note payable	**180.0**	172.4
Commercial paper	**376.8**	334.8
Current maturities of long-term debt	**351.1**	382.1
Accounts payable	**340.0**	323.7
Accrued taxes	**35.1**	33.3
Accrued interest	**42.8**	50.8
Accrued compensation and benefits	**50.1**	52.1
Pension and post-retirement liability	**2.7**	3.0
Other	**59.2**	32.6
Total	**1,448.8**	1,384.8
Deferred Credits and Other Liabilities		
Deferred income taxes	**621.7**	1,329.7
Deferred tax credits	**124.8**	126.2
Asset retirement obligations	**262.5**	316.0
Pension and post-retirement liability	**535.0**	488.3
Regulatory liabilities	**1,106.3**	309.9
Other	**81.4**	87.9
Total	**2,731.7**	2,658.0
Capitalization		
Great Plains Energy shareholders' equity		
Common stock - 600,000,000 shares authorized without par value 215,801,723 and 215,479,105 shares issued, stated value	**4,233.1**	4,217.0
Preference stock - 11,000,000 shares authorized without par value 7.00% Series B Mandatory Convertible Preferred Stock $1,000 per share liquidation preference, 0 and 862,500 shares issued and outstanding	**—**	836.2
Retained earnings	**737.9**	1,119.2
Treasury stock - 137,589 and 128,087 shares, at cost	**(4.0)**	(3.8)
Accumulated other comprehensive loss	**(2.2)**	(6.6)
Total shareholders' equity	**4,964.8**	6,162.0
Long-term debt (Note 12)	**3,312.6**	3,365.2
Total	**8,277.4**	9,527.2
Commitments and Contingencies (Note 15)		
Total	**$ 12,457.9**	$ 13,570.0

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

GREAT PLAINS ENERGY INCORPORATED

Consolidated Statements of Cash Flows

Year Ended December 31	**2017**	2016	2015
Cash Flows from Operating Activities		(millions)	
Net income (loss)	**$ (106.2)**	$ 290.0	$ 213.0
Adjustments to reconcile income (loss) to net cash from operating activities:			
Depreciation and amortization	**371.1**	344.8	330.4
Amortization of:			
Nuclear fuel	**32.1**	26.6	26.8
Other	**63.9**	77.5	47.7
Deferred income taxes, net	**235.4**	170.1	124.9
Investment tax credit amortization	**(1.4)**	(1.4)	(1.4)
Income from equity investments, net of income taxes	**(2.5)**	(2.0)	(1.2)
Fair value impacts of interest rate swaps	**(12.1)**	(79.3)	—
Loss on Series B Preferred Stock dividend make-whole provisions (Note 14)	**124.8**	—	—
Loss on extinguishment of debt (Note 12)	**82.8**	—	—
Other operating activities (Note 3)	**22.6**	(42.3)	12.9
Net cash from operating activities	**810.5**	784.0	753.1
Cash Flows from Investing Activities			
Utility capital expenditures	**(573.5)**	(609.4)	(677.1)
Allowance for borrowed funds used during construction	**(7.4)**	(6.8)	(5.8)
Purchases of nuclear decommissioning trust investments	**(33.6)**	(31.9)	(50.9)
Proceeds from nuclear decommissioning trust investments	**30.3**	28.6	47.6
Purchase of time deposit	**—**	(1,000.0)	—
Proceeds from time deposit	**1,000.0**	—	—
Other investing activities	**(45.6)**	(64.0)	(48.2)
Net cash from investing activities	**370.2**	(1,683.5)	(734.4)
Cash Flows from Financing Activities			
Issuance of common stock	**2.9**	1,603.7	3.0
Issuance of preferred stock	**—**	862.5	—
Issuance of long-term debt	**4,591.1**	—	348.8
Issuance of long-term debt from remarketing	**—**	—	146.5
Repayment of long-term debt from remarketing	**—**	—	(146.5)
Issuance fees	**(38.3)**	(143.6)	(3.0)
Repayment of long-term debt, including redemption premium	**(4,725.1)**	(1.1)	(87.0)
Net change in short-term borrowings	**53.0**	100.8	(128.3)
Net change in collateralized short-term borrowings	**7.6**	(2.6)	4.0
Dividends paid	**(272.0)**	(194.0)	(155.5)
Redemption of preferred stock	**(963.4)**	(40.1)	—
Other financing activities	**(4.2)**	(4.3)	(2.4)
Net cash from financing activities	**(1,348.4)**	2,181.3	(20.4)
Net Change in Cash and Cash Equivalents	**(167.7)**	1,281.8	(1.7)
Cash and Cash Equivalents at Beginning of Year	**1,293.1**	11.3	13.0
Cash and Cash Equivalents at End of Year	**$ 1,125.4**	$ 1,293.1	$ 11.3

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

GREAT PLAINS ENERGY INCORPORATED

Consolidated Statements of Shareholders' Equity

Year Ended December 31	**2017**		2016		2015	
	Shares	**Amount**	Shares	Amount	Shares	Amount
Common Stock			(millions, except share amounts)			
Beginning balance	**215,479,105**	**$ 4,217.0**	154,504,900	$ 2,646.7	154,254,037	$ 2,639.3
Issuance of common stock	**322,618**	**11.7**	60,974,205	1,565.3	250,863	6.6
Equity compensation expense, net of forfeitures		**5.4**		4.3		1.9
Unearned Compensation						
Issuance of restricted common stock		**(2.3)**		(2.8)		(2.4)
Forfeiture of restricted common stock		**0.7**		—		0.5
Compensation expense recognized		**2.1**		2.7		1.8
Other		**(1.5)**		0.8		(1.0)
Ending balance	**215,801,723**	**4,233.1**	215,479,105	4,217.0	154,504,900	2,646.7
Cumulative Preferred Stock						
Beginning balance	—	—	390,000	39.0	390,000	39.0
Redemption of cumulative preferred stock	—	—	(390,000)	(39.0)	—	—
Ending balance	**—**	**—**	—	—	390,000	39.0
Preference Stock						
Beginning balance	**862,500**	**836.2**	—	—	—	—
Issuance of Series B Preferred Stock	**—**	**—**	862,500	836.2	—	—
Redemption of Series B Preferred Stock	**(862,500)**	**(836.2)**	—	—	—	—
Ending balance	**—**	**—**	862,500	836.2	—	—
Retained Earnings						
Beginning balance		**1,119.2**		1,024.4		967.8
Net income (loss)		**(106.2)**		290.0		213.0
Redemption premium on preferred stock		**(2.4)**		(0.6)		—
Dividends:						
Common stock ($1.10, $1.0625 and $0.9975 per share)		**(237.1)**		(181.0)		(153.9)
Preferred stock - at required rates		**(34.9)**		(13.0)		(1.6)
Performance shares		**(0.7)**		(0.6)		(0.9)
Ending balance		**737.9**		1,119.2		1,024.4
Treasury Stock						
Beginning balance	**(128,087)**	**(3.8)**	(101,229)	(2.6)	(91,281)	(2.3)
Treasury shares acquired	**(149,544)**	**(4.3)**	(138,021)	(4.1)	(76,468)	(2.0)
Treasury shares reissued	**140,042**	**4.1**	111,163	2.9	66,520	1.7
Ending balance	**(137,589)**	**(4.0)**	(128,087)	(3.8)	(101,229)	(2.6)
Accumulated Other Comprehensive Income (Loss)						
Beginning balance		**(6.6)**		(12.0)		(18.7)
Derivative hedging activity, net of tax		**4.9**		5.6		5.7
Change in unrecognized pension expense, net of tax		**(0.5)**		(0.2)		1.0
Ending balance		**(2.2)**		(6.6)		(12.0)
Total Great Plains Energy Shareholders' Equity		**$ 4,964.8**		$ 6,162.0		$ 3,695.5

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

KANSAS CITY POWER & LIGHT COMPANY

Consolidated Statements of Comprehensive Income

Year Ended December 31	2017	2016	2015
Operating Revenues		(millions)	
Electric revenues	$ 1,890.7	$ 1,875.4	$ 1,713.8
Operating Expenses			
Fuel and purchased power	412.1	372.7	397.1
Transmission	68.6	56.4	58.4
Operating and maintenance expenses	506.4	525.8	494.2
Costs to achieve the anticipated merger with Westar Energy, Inc.	10.5	10.9	—
Depreciation and amortization	266.3	247.5	235.7
General taxes	182.5	177.5	163.5
Other	0.6	2.5	0.9
Total	1,447.0	1,393.3	1,349.8
Operating income	443.7	482.1	364.0
Other Income (Expense)			
Non-operating income	11.2	11.8	8.4
Non-operating expenses	(8.1)	(7.6)	(7.2)
Total	3.1	4.2	1.2
Interest charges	(138.8)	(139.4)	(135.6)
Income before income tax expense	308.0	346.9	229.6
Income tax expense	(128.2)	(121.9)	(76.8)
Net income	$ 179.8	$ 225.0	$ 152.8
Comprehensive Income			
Net income	$ 179.8	$ 225.0	$ 152.8
Other comprehensive income			
Derivative hedging activity			
Reclassification to expenses, net of tax	4.6	5.4	5.3
Derivative hedging activity, net of tax	4.6	5.4	5.3
Total other comprehensive income	4.6	5.4	5.3
Comprehensive income	$ 184.4	$ 230.4	$ 158.1

The disclosures regarding KCP&L included in the accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

KANSAS CITY POWER & LIGHT COMPANY

Consolidated Balance Sheets

	December 31	
	2017	2016
ASSETS	(millions, except share amounts)	
Current Assets		
Cash and cash equivalents	**$ 2.2**	$ 4.5
Receivables, net	**106.3**	139.1
Related party receivables	**84.7**	67.2
Accounts receivable pledged as collateral	**130.0**	110.0
Fuel inventories, at average cost	**71.0**	72.9
Materials and supplies, at average cost	**126.0**	118.9
Deferred refueling outage costs	**6.8**	22.3
Refundable income taxes	**5.4**	12.7
Prepaid expenses and other assets	**27.6**	27.9
Total	**560.0**	575.5
Utility Plant, at Original Cost		
Electric	**10,213.2**	9,925.1
Less - accumulated depreciation	**4,070.3**	3,858.4
Net utility plant in service	**6,142.9**	6,066.7
Construction work in progress	**350.3**	300.4
Nuclear fuel, net of amortization of $204.2 and $172.1	**72.4**	62.0
Total	**6,565.6**	6,429.1
Investments and Other Assets		
Nuclear decommissioning trust fund	**258.4**	222.9
Regulatory assets	**691.9**	801.8
Other	**48.0**	29.1
Total	**998.3**	1,053.8
Total	**$ 8,123.9**	$ 8,058.4

The disclosures regarding KCP&L included in the accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

KANSAS CITY POWER & LIGHT COMPANY

Consolidated Balance Sheets

	December 31	
	2017	2016
LIABILITIES AND CAPITALIZATION	(millions, except share amounts)	
Current Liabilities		
Collateralized note payable	**$ 130.0**	$ 110.0
Commercial paper	**167.5**	132.9
Current maturities of long-term debt	**350.0**	281.0
Accounts payable	**249.0**	231.6
Accrued taxes	**29.0**	27.0
Accrued interest	**32.4**	32.4
Accrued compensation and benefits	**50.1**	52.1
Pension and post-retirement liability	**1.4**	1.6
Other	**46.8**	11.4
Total	**1,056.2**	880.0
Deferred Credits and Other Liabilities		
Deferred income taxes	**616.1**	1,228.3
Deferred tax credits	**121.8**	122.8
Asset retirement obligations	**231.4**	278.0
Pension and post-retirement liability	**512.2**	465.8
Regulatory liabilities	**779.2**	187.4
Other	**61.6**	70.6
Total	**2,322.3**	2,352.9
Capitalization		
Common shareholder's equity		
Common stock - 1,000 shares authorized without par value		
1 share issued, stated value	**1,563.1**	1,563.1
Retained earnings	**949.7**	982.6
Accumulated other comprehensive income (loss)	**0.4**	(4.2)
Total	**2,513.2**	2,541.5
Long-term debt (Note 12)	**2,232.2**	2,284.0
Total	**4,745.4**	4,825.5
Commitments and Contingencies (Note 15)		
Total	**$ 8,123.9**	$ 8,058.4

The disclosures regarding KCP&L included in the accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

KANSAS CITY POWER & LIGHT COMPANY

Consolidated Statements of Cash Flows

Year Ended December 31	2017	2016	2015
Cash Flows from Operating Activities		(millions)	
Net income	$ 179.8	$ 225.0	$ 152.8
Adjustments to reconcile income to net cash from operating activities:			
Depreciation and amortization	266.3	247.5	235.7
Amortization of:			
Nuclear fuel	32.1	26.6	26.8
Other	30.2	33.9	29.1
Deferred income taxes, net	83.5	93.4	99.4
Investment tax credit amortization	(1.0)	(1.0)	(1.0)
Other operating activities (Note 3)	20.0	(2.1)	(61.5)
Net cash from operating activities	610.9	623.3	481.3
Cash Flows from Investing Activities			
Utility capital expenditures	(437.7)	(418.8)	(518.3)
Allowance for borrowed funds used during construction	(6.1)	(5.6)	(3.9)
Purchases of nuclear decommissioning trust investments	(33.6)	(31.9)	(50.9)
Proceeds from nuclear decommissioning trust investments	30.3	28.6	47.6
Other investing activities	(23.9)	(23.8)	(25.5)
Net cash from investing activities	(471.0)	(451.5)	(551.0)
Cash Flows from Financing Activities			
Issuance of long-term debt	299.2	—	348.8
Issuance of long-term debt from remarketing	—	—	146.5
Repayment of long-term debt from remarketing	—	—	(146.5)
Issuance fees	(3.0)	(0.2)	(3.0)
Repayment of long-term debt	(281.0)	—	(85.9)
Net change in short-term borrowings	34.6	(47.4)	(178.0)
Net change in collateralized short-term borrowings	20.0	—	—
Net money pool borrowings	—	—	(12.6)
Dividends paid to Great Plains Energy	(212.0)	(122.0)	—
Net cash from financing activities	(142.2)	(169.6)	69.3
Net Change in Cash and Cash Equivalents	(2.3)	2.2	(0.4)
Cash and Cash Equivalents at Beginning of Year	4.5	2.3	2.7
Cash and Cash Equivalents at End of Year	$ 2.2	$ 4.5	$ 2.3

The disclosures regarding KCP&L included in the accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

KANSAS CITY POWER & LIGHT COMPANY

Consolidated Statements of Common Shareholder's Equity

Year Ended December 31	**2017**		2016		2015	
	Shares	**Amount**	Shares	Amount	Shares	Amount
		(millions, except share amounts)				
Common Stock	**1**	**$ 1,563.1**	1	$ 1,563.1	1	$ 1,563.1
Retained Earnings						
Beginning balance		**982.6**		879.6		726.8
Net income		**179.8**		225.0		152.8
Cumulative effect of adoption of ASU 2016-09 (Note 1)		**(0.7)**		—		—
Dividends:						
Common stock held by Great Plains Energy		**(212.0)**		(122.0)		—
Ending balance		**949.7**		982.6		879.6
Accumulated Other Comprehensive Income (Loss)						
Beginning balance		**(4.2)**		(9.6)		(14.9)
Derivative hedging activity, net of tax		**4.6**		5.4		5.3
Ending balance		**0.4**		(4.2)		(9.6)
Total Common Shareholder's Equity		**$ 2,513.2**		$ 2,541.5		$ 2,433.1

The disclosures regarding KCP&L included in the accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

GREAT PLAINS ENERGY INCORPORATED
KANSAS CITY POWER & LIGHT COMPANY

Notes to Consolidated Financial Statements

The notes to consolidated financial statements that follow are a combined presentation for Great Plains Energy Incorporated and Kansas City Power & Light Company, both registrants under this filing. The terms "Great Plains Energy," "Company," "KCP&L" and "Companies" are used throughout this report. "Great Plains Energy" and the "Company" refer to Great Plains Energy Incorporated and its consolidated subsidiaries, unless otherwise indicated. "KCP&L" refers to Kansas City Power & Light Company and its consolidated subsidiaries. "Companies" refers to Great Plains Energy Incorporated and its consolidated subsidiaries and KCP&L and its consolidated subsidiaries.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization

Great Plains Energy, a Missouri corporation incorporated in 2001, is a public utility holding company and does not own or operate any significant assets other than the stock of its subsidiaries and cash and cash equivalents. Great Plains Energy's wholly owned direct subsidiaries with significant operations are as follows:

- KCP&L is an integrated, regulated electric utility that provides electricity to customers primarily in the states of Missouri and Kansas. KCP&L has one active wholly owned subsidiary, Kansas City Power & Light Receivables Company (KCP&L Receivables Company).
- KCP&L Greater Missouri Operations Company (GMO) is an integrated, regulated electric utility that provides electricity to customers in the state of Missouri. GMO also provides regulated steam service to certain customers in the St. Joseph, Missouri area. GMO has two active wholly owned subsidiaries, GMO Receivables Company and MPS Merchant Services, Inc. (MPS Merchant). MPS Merchant has certain long-term natural gas contracts remaining from its former non-regulated trading operations.

Great Plains Energy also wholly owns GPE Transmission Holding Company, LLC (GPETHC). GPETHC owns 13.5% of Transource Energy, LLC (Transource) with the remaining 86.5% owned by AEP Transmission Holding Company, LLC (AEPTHC), a subsidiary of American Electric Power Company, Inc. GPETHC accounts for its investment in Transource under the equity method. Transource is focused on the development of competitive electric transmission projects.

Each of Great Plains Energy's and KCP&L's consolidated financial statements includes the accounts of their subsidiaries. Intercompany transactions have been eliminated.

Great Plains Energy's sole reportable business segment is the electric utility segment (Electric Utility). See Note 22 for additional information.

Use of Estimates

The process of preparing financial statements in conformity with Generally Accepted Accounting Principles (GAAP) requires the use of estimates and assumptions that affect the reported amounts of certain types of assets, liabilities, revenues and expenses. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements. Accordingly, upon settlement, actual results may differ from estimated amounts.

Cash and Cash Equivalents

Cash equivalents consist of highly liquid investments with original maturities of three months or less at acquisition.

Time Deposit

Consists of a non-negotiable fixed rate investment in a time deposit with an original maturity of greater than three months and is recorded on the balance sheet at cost. The Company estimates the fair value of the time deposit, which approximates its carrying value, using Level 2 inputs based on current interest rates for similar investments with comparable credit risk and time to maturity.

Fair Value of Financial Instruments
The following methods and assumptions were used to estimate the fair value of each class of financial instrument for which it is practicable to estimate that value.

Nuclear decommissioning trust fund - KCP&L's nuclear decommissioning trust fund assets are recorded at fair value based on quoted market prices of the investments held by the fund and/or valuation models.

Pension plans - For financial reporting purposes, the market value of plan assets is the fair value. For regulatory reporting purposes, a five-year smoothing of assets is used to determine fair value.

Derivative Instruments
The Company records derivative instruments on the balance sheet at fair value in accordance with GAAP. Great Plains Energy and KCP&L enter into derivative contracts to manage exposure to commodity price and interest rate fluctuations. Derivative instruments are entered into solely for hedging purposes and are not issued or held for speculative reasons.

The Company considers various qualitative factors, such as contract and market place attributes, in designating derivative instruments at inception. Great Plains Energy and KCP&L may elect the normal purchases and normal sales (NPNS) exception, which requires the effects of the derivative to be recorded when the underlying contract settles. Great Plains Energy and KCP&L account for derivative instruments that are not designated as NPNS as non-hedging derivatives, which are recorded as assets or liabilities on the consolidated balance sheets at fair value.

Great Plains Energy and KCP&L offset fair value amounts recognized for derivative instruments under master netting arrangements, which include rights to reclaim cash collateral (a receivable), or the obligation to return cash collateral (a payable).

Utility Plant
Great Plains Energy's and KCP&L's utility plant is stated at historical cost. These costs include taxes, an allowance for the cost of borrowed and equity funds used to finance construction and payroll-related costs, including pensions and other fringe benefits. Replacements, improvements and additions to units of property are capitalized. Repairs of property and replacements of items not considered to be units of property are expensed as incurred (except as discussed under Deferred Refueling Outage Costs). When property units are retired or otherwise disposed, the original cost, net of salvage, is charged to accumulated depreciation. Substantially all of KCP&L's utility plant is pledged as collateral for KCP&L's mortgage bonds under the General Mortgage Indenture and Deed of Trust dated December 1, 1986, as supplemented (Indenture). A portion of GMO's utility plant is pledged as collateral for GMO's mortgage bonds under the General Mortgage Indenture and Deed of Trust dated April 1, 1946, as supplemented.

As prescribed by The Federal Energy Regulatory Commission (FERC), Allowance for Funds Used During Construction (AFUDC) is charged to the cost of the plant during construction. AFUDC equity funds are included as a non-cash item in non-operating income and AFUDC borrowed funds are a reduction of interest charges. The rates used to compute gross AFUDC are compounded semi-annually. The rates used to compute gross AFUDC for KCP&L averaged 4.9% in 2017, 5.7% in 2016 and 3.0% in 2015. The rates used to compute gross AFUDC for GMO averaged 1.9% in 2017, 1.6% in 2016 and 4.2% in 2015.

Great Plains Energy's and KCP&L's balances of utility plant, at original cost, with a range of estimated useful lives are listed in the following tables.

Great Plains Energy

December 31	**2017**	**2016**
Utility plant, at original cost	(millions)	
Generation (20 - 60 years)	$ 7,930.8	$ 8,106.4
Transmission (15 - 70 years)	912.3	886.3
Distribution (8 - 66 years)	3,789.0	3,629.1
General (5 - 50 years)	1,042.0	975.9
Total [(a)]	$ 13,674.1	$ 13,597.7

[(a)] Includes $265.0 million and $261.2 million at December 31, 2017 and 2016, respectively, of land and other assets that are not depreciated.

KCP&L

December 31	**2017**	**2016**
Utility plant, at original cost	(millions)	
Generation (20 - 60 years)	$ 6,471.5	$ 6,350.7
Transmission (15 - 70 years)	500.4	484.1
Distribution (8 - 55 years)	2,389.4	2,298.4
General (5 - 50 years)	851.9	791.9
Total [(a)]	$ 10,213.2	$ 9,925.1

[(a)] Includes $176.0 million and $178.0 million at December 31, 2017 and 2016, respectively, of land and other assets that are not depreciated.

Plant to be Retired, Net

When Great Plains Energy and KCP&L retire utility plant, the original cost, net of salvage, is charged to accumulated depreciation. However, when it becomes probable an asset will be retired significantly in advance of its original expected useful life and in the near term, the cost of the asset and related accumulated depreciation is recognized as a separate asset as a probable abandonment. If the asset is still in service, the net amount is classified as plant to be retired, net on the consolidated balance sheets. If the asset is no longer in service, the net amount is classified in regulatory assets on the consolidated balance sheets.

Great Plains Energy and KCP&L must also assess the probability of full recovery of the remaining net book value of the abandonment. The net book value that may be retained as an asset on the balance sheet for the abandonment is dependent upon amounts that may be recovered through regulated rates, including any return. An impairment charge, if any, would equal the difference between the remaining net book value of the asset and the present value of the future revenues expected from the asset.

In June 2017, Great Plains Energy and KCP&L announced the expected retirement of certain older generating units, including GMO's Sibley No. 3 Unit, over the next several years. As of December 31, 2017, Great Plains Energy has determined that Sibley No. 3 Unit meets the criteria to be considered probable of abandonment and has classified its remaining net book value of $143.6 million within plant to be retired, net on its consolidated balance sheet. The Company is currently allowed a full recovery of and a full return on Sibley No. 3 Unit in rates and has concluded that no impairment is required as of December 31, 2017.

Depreciation and Amortization

Depreciation and amortization of utility plant other than nuclear fuel is computed using the straight-line method over the estimated lives of depreciable property based on rates approved by state regulatory authorities. Annual depreciation rates average approximately 3%. Nuclear fuel is amortized to fuel expense based on the quantity of heat produced during the generation of electricity.

Great Plains Energy's depreciation expense was $330.8 million, $308.8 million and $299.4 million for 2017, 2016 and 2015, respectively. KCP&L's depreciation expense was $228.4 million, $215.4 million and $208.5 million for 2017, 2016 and 2015, respectively.

Nuclear Plant Decommissioning Costs
Nuclear plant decommissioning cost estimates are based on the immediate dismantlement method and include the costs of decontamination, dismantlement and site restoration. Based on these cost estimates, KCP&L contributes to a tax-qualified trust fund to be used to decommission Wolf Creek Generating Station (Wolf Creek). Related liabilities for decommissioning are included on Great Plains Energy's and KCP&L's balance sheets in Asset Retirement Obligations (AROs).

As a result of the authorized regulatory treatment and related regulatory accounting, differences between the decommissioning trust fund asset and the related ARO are recorded as a regulatory asset or liability. See Note 8 for discussion of AROs including those associated with nuclear plant decommissioning costs.

Deferred Refueling Outage Costs
KCP&L uses the deferral method to account for operations and maintenance expenses incurred in support of Wolf Creek's scheduled refueling outages and amortizes them evenly (monthly) over the unit's operating cycle, which is approximately 18 months, until the next scheduled outage. Replacement power costs during an outage are expensed as incurred.

Regulatory Matters
KCP&L and GMO defer items on the balance sheet resulting from the effects of the ratemaking process, which would not be recorded if KCP&L and GMO were not regulated. See Note 6 for additional information concerning regulatory matters.

Revenue Recognition
Great Plains Energy and KCP&L recognize revenues on sales of electricity when the service is provided. Revenues recorded include electric services provided but not yet billed by KCP&L and GMO. Unbilled revenues are recorded for kWh usage in the period following the customers' billing cycle to the end of the month. KCP&L's and GMO's estimate is based on net system kWh usage less actual billed kWhs. KCP&L's and GMO's estimated unbilled kWhs are allocated and priced by regulatory jurisdiction across the rate classes based on actual billing rates.

KCP&L and GMO collect from customers gross receipts taxes levied by state and local governments. These taxes from KCP&L's Missouri customers are recorded gross in operating revenues and general taxes on Great Plains Energy's and KCP&L's statements of comprehensive income. KCP&L's gross receipts taxes collected from Missouri customers were $72.9 million, $70.3 million and $62.0 million in 2017, 2016 and 2015, respectively. These taxes from KCP&L's Kansas customers and GMO's customers are recorded net in operating revenues on Great Plains Energy's and KCP&L's statements of comprehensive income (loss).

Great Plains Energy and KCP&L collect sales taxes from customers and remit to state and local governments. These taxes are presented on a net basis on Great Plains Energy's and KCP&L's statements of comprehensive income (loss).

Great Plains Energy and KCP&L record sale and purchase activity on a net basis in wholesale revenue or purchased power when transacting with Regional Transmission Organization (RTO)/Independent System Operator (ISO) markets.

Allowance for Doubtful Accounts
This reserve represents estimated uncollectible accounts receivable and is based on management's judgment considering historical loss experience and the characteristics of existing accounts. Provisions for losses on receivables are expensed to maintain the allowance at a level considered adequate to cover expected losses. Receivables are charged off against the reserve when they are deemed uncollectible.

Property Gains and Losses
Net gains and losses from the sale of assets and businesses and from asset impairments are recorded in operating expenses.

Asset Impairments
Long-lived assets and finite-lived intangible assets subject to amortization are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If the sum of the undiscounted expected future cash flows from an asset to be held and used is less than the carrying value of the asset, an asset impairment must be recognized in the financial statements. The amount of impairment recognized is the excess of the carrying value of the asset over its fair value.

Goodwill and indefinite lived intangible assets are tested for impairment annually and when an event occurs indicating the possibility that an impairment exists. The annual test must be performed at the same time each year. The goodwill impairment test consists of comparing the fair value of a reporting unit to its carrying amount, including goodwill, to identify potential impairment. In the event that the carrying amount exceeds the fair value of the reporting unit, an impairment loss is recognized for the difference between the carrying amount of the reporting unit and its fair value.

Income Taxes
Income taxes are accounted for using the asset/liability approach. Deferred tax assets and liabilities are determined based on the temporary differences between the financial reporting and tax bases of assets and liabilities, applying enacted statutory tax rates in effect for the year in which the differences are expected to reverse. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion of the deferred tax assets will not be realized.

Great Plains Energy and KCP&L recognize tax benefits based on a “more-likely-than-not” recognition threshold. In addition, Great Plains Energy and KCP&L recognize interest accrued related to unrecognized tax benefits in interest expense and penalties in non-operating expenses.

Great Plains Energy files a consolidated federal income tax return as well as unitary and combined income tax returns in several state jurisdictions with Kansas and Missouri being the most significant. Income taxes for consolidated or combined subsidiaries are allocated to the subsidiaries based on separate company computations of income or loss. KCP&L's income tax provision includes taxes allocated based on its separate company income or loss.

As of December 31, 2017, Great Plains Energy and KCP&L have established a net regulatory liability for the additional future refunds to be made to customers for the over collection of income taxes in rates. Tax credits are recognized in the year generated except for certain KCP&L and GMO investment tax credits that have been deferred and amortized over the remaining service lives of the related properties.

Environmental Matters
Environmental costs are accrued when it is probable a liability has been incurred and the amount of the liability can be reasonably estimated.

Non-Operating Income and Expenses
In 2017, Great Plains Energy's non-operating income included $22.8 million of interest income earned on increased cash and cash equivalents at Great Plains Energy in 2017 related to the proceeds from Great Plains Energy's October 2016 common stock and Series B Preferred Stock offerings and March 2017 issuance of $4.3 billion of senior notes and $14.0 million of mark-to-market gains on deal contingent interest rate swaps.

In 2017, Great Plains Energy's non-operating expenses included $15.0 million due to the write-off of previously deferred offering fees as a result of the termination of the stock purchase agreement for $750 million of Series A Preferred Stock between Great Plains Energy and OCM Credit Portfolio LP (OMERS) in July 2017.

Basic and Diluted Earnings (Loss) per Common Share Calculation

To determine basic earnings (loss) per common share (EPS), preferred stock dividend requirements and redemption premium are deducted from net income (loss) before dividing by the average number of common shares outstanding. To determine diluted EPS, preferred stock dividend requirements and redemption premium are added to earnings available for common shareholders for the periods in which the assumed conversion of Great Plains Energy's 7.00% Series B Mandatory Convertible Preferred Stock (Series B Preferred Stock) has a dilutive effect before dividing by the diluted average number of common shares outstanding. See Note 14 for additional information regarding Series B Preferred Stock. The effect of dilutive securities assumes the issuance of common shares applicable to performance shares and restricted stock calculated using the treasury stock method and the number of common shares that would be issued under an assumed conversion of Series B Preferred Stock using the if-converted method.

The following table reconciles Great Plains Energy's basic and diluted EPS.

	2017	2016	2015
	(millions, except per share amounts)		
Income (Loss)			
Net income (loss)	$ (106.2)	$ 290.0	$ 213.0
Less: preferred stock dividend requirements and redemption premium	37.3	16.5	1.6
Earnings (loss) available for common shareholders	$ (143.5)	$ 273.5	$ 211.4
Common Shares Outstanding			
Average number of common shares outstanding	215.5	169.4	154.2
Add: effect of dilutive securities	—	0.4	0.6
Diluted average number of common shares outstanding	215.5	169.8	154.8
Basic and Diluted EPS	$ (0.67)	$ 1.61	$ 1.37

Anti-dilutive shares excluded from the computation of diluted EPS for 2017 were 226,958 performance shares and 144,989 restricted stock shares. Anti-dilutive shares excluded from the computation of diluted EPS for 2016 were 7,805,460 shares of Series B Preferred Stock assumed to be converted. Anti-dilutive shares excluded from the computation of diluted EPS for 2015 were 900 restricted stock shares.

Dividends Declared

In February 2018, Great Plains Energy's Board of Directors (Great Plains Energy Board) declared a quarterly dividend of $0.275 per share on Great Plains Energy's common stock. The common dividend is payable March 20, 2018, to shareholders of record as of February 27, 2018.

In February 2018, KCP&L's Board of Directors declared a cash dividend payable to Great Plains Energy of $60 million payable on March 19, 2018.

New Accounting Standards

In March 2016, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2016-09, *Compensation-Stock Compensation*, which is intended to simplify several areas of accounting for share-based compensation arrangements, including the income tax impact, classification on the statement of cash flows and forfeitures. The Companies adopted ASU No. 2016-09 on January 1, 2017. The cumulative effect from the adoption of ASU No. 2016-09 was insignificant to Great Plains Energy's consolidated financial statements and resulted in a reduction to retained earnings of $0.7 million for KCP&L. The Companies have elected to adopt the cash flow presentation of the excess tax benefits as an operating activity prospectively and no prior periods have been adjusted.

In March 2017, the FASB issued ASU No. 2017-07, *Compensation-Retirement Benefits*, which requires an employer to disaggregate the service cost component from the other components of net benefit cost. The service cost component is to be reported in the same line item or items as other compensation costs arising from services rendered by the pertinent employees during the period. The non-service cost components are to be reported separately from service costs and outside of a subtotal of income from operations. The amendments in this update allow only the service cost component to be eligible for capitalization as part of utility plant. The non-service cost components that are no longer eligible for capitalization as part of utility plant will be recorded as a regulatory asset. The new guidance is to be applied retrospectively for the presentation of service cost and non-service cost components in the income statement and prospectively for the capitalization of the service cost component. The Companies adopted ASU No. 2017-07 on January 1, 2018, and it will not have a material impact on their consolidated financial statements as the impacts of adoption are limited to changes in the classification of non-service cost.

In May 2014, the FASB issued ASU No. 2014-09, *Revenue from Contracts with Customers*, which requires an entity to recognize the amount of revenue to which it expects to be entitled for the transfer of promised goods or services to customers. In August 2015, the FASB issued ASU No. 2015-14, deferring the effective date of ASU No. 2014-09 one year, from January 1, 2017, to January 1, 2018. The ASU replaced most existing revenue recognition guidance in GAAP when it became effective. The Companies adopted ASU No. 2014-09 on January 1, 2018 using the modified retrospective transition method. The adoption of the standard did not have a material impact on the Companies' amount or timing of revenue recognition. The Companies will include additional disclosures regarding the nature, amount and timing of their revenues from contracts with customers, including disaggregated revenue by customer type, in their first quarter 2018 notes to financial statements.

In February 2016, the FASB issued ASU No. 2016-02, *Leases*, which requires an entity that is a lessee to record a right-of-use asset and a lease liability for lease payments on the balance sheet for all leases with terms longer than 12 months. Leases will be classified as either finance or operating, with classification affecting the pattern of expense recognition in the income statement. The new guidance is effective for interim and annual periods beginning after December 15, 2018, and is required to be applied using a modified retrospective approach. Great Plains Energy and KCP&L plan to adopt the new guidance on January 1, 2019. The Companies expect that the new guidance will affect the balance sheet by increasing the assets and liabilities recorded related to operating leases and continue to evaluate the effect that ASU No. 2016-02 will have on their income statement, statement of cash flows and related disclosures.

2. ANTICIPATED MERGER WITH WESTAR ENERGY, INC.

In May 2016, Great Plains Energy entered into an Agreement and Plan of Merger dated as of May 29, 2016, by and among Great Plains Energy, Westar Energy, Inc. (Westar) and GP Star, Inc. (GP Star) (Original Merger Agreement). Pursuant to the Original Merger Agreement, Great Plains Energy would have acquired Westar for (i) $51.00 in cash and (ii) a number of shares of Great Plains Energy common stock, equal to an exchange ratio for each share of Westar common stock issued and outstanding immediately prior to the effective time of the merger, with Westar becoming a wholly owned subsidiary of Great Plains Energy. The acquisition was subject to various shareholder and regulatory approvals, including from The State Corporation Commission of the State of Kansas (KCC), the Public Service Commission of the State of Missouri (MPSC) and FERC.

In April, 2017, KCC issued an order denying Great Plains Energy's, KCP&L's and Westar's joint application for approval of the acquisition of Westar by Great Plains Energy citing concerns with the purchase price, Great Plains Energy's capital structure, quantifiable and demonstrable customer benefits and staffing levels in Westar's service territory, among other items.

In July 2017, Great Plains Energy entered into an Amended and Restated Agreement and Plan of Merger dated as of July 9, 2017 by and among Great Plains Energy, Westar, Monarch Energy Holding, Inc., a Missouri corporation (Holdco), and King Energy, Inc., a Kansas corporation and wholly owned subsidiary of Holdco (Merger Sub) (Amended Merger Agreement). Pursuant to the Amended Merger Agreement, subject to the satisfaction or waiver of certain conditions, Great Plains Energy will merge with and into Holdco, with Holdco surviving such merger, and Merger Sub will merge with and into Westar, with Westar surviving such merger. Pursuant to the Amended Merger Agreement, at closing each outstanding share of Great Plains Energy's and Westar's common stock will be converted into the right to receive 0.5981 and 1.0, respectively, of validly issued, fully paid and nonassessable shares of common stock, no par value, of Holdco. Following the mergers, Holdco, with a new name that has yet to be established, will be the parent of Great Plains Energy's direct subsidiaries, including KCP&L, and Westar.

The anticipated merger with Westar has been structured as a merger of equals in a tax-free exchange of shares that involves no premium paid or received with respect to either Great Plains Energy or Westar. Following the completion of the anticipated merger, Westar shareholders will own approximately 52.5 percent and Great Plains Energy shareholders will own approximately 47.5 percent of the combined company.

Regulatory and Shareholder Approvals
Great Plains Energy's anticipated merger with Westar was unanimously approved by the Great Plains Energy Board and Westar's Board of Directors (Westar Board). In November 2017, shareholders of Great Plains Energy and Westar approved all proposals necessary for the merger of Great Plains Energy and Westar at each company's respective shareholder meeting. The anticipated merger remains subject to regulatory approvals from KCC, the MPSC, the Nuclear Regulatory Commission (NRC), FERC and The Federal Communications Commission (FCC); as well as other contractual conditions.

KCC Approval
In August 2017, Great Plains Energy, KCP&L and Westar filed a joint application with KCC for approval of the anticipated merger with Westar. An evidentiary hearing is expected to occur in March 2018 and a decision from KCC on the joint application is expected by June 5, 2018.

MPSC Approval
In August 2017, Great Plains Energy, KCP&L, GMO and Westar filed a joint application with the MPSC for approval of the anticipated merger with Westar. In January 2018, Great Plains Energy, KCP&L, GMO and Westar reached a stipulation and agreement with the MPSC staff and certain other intervenors in the case settling all issues in the joint application except for the assignment of bill credit amounts to retail electric customers at KCP&L and GMO. The stipulation and agreement imposes certain conditions on Holdco, KCP&L and GMO in the areas of financing, ratemaking, customer service, corporate social responsibility and also includes other general provisions. The stipulation and agreement with the MPSC staff, among other things, provides that retail rates for KCP&L Missouri and GMO customers will not increase as a result of the merger and that in the event KCP&L's or GMO's credit ratings are downgraded below investment grade as a result of their affiliation with Holdco or any of Holdco's affiliates, KCP&L and GMO will be restricted from paying a dividend unless approved by the MPSC or until their credit ratings are restored to investment grade. The stipulation and agreement must still be approved by the MPSC. An evidentiary hearing in the case is expected to occur in March 2018. While there is not a statutory deadline for an MPSC ruling on the joint application, a decision from the MPSC is expected in the second quarter of 2018.

Other Approvals
In September 2017, Great Plains Energy and Westar filed applications with FERC and the NRC for approval of the merger. In October 2017, the Securities and Exchange Commission (SEC) declared effective a registration statement on Form S-4 of Holdco including a joint proxy statement of Great Plains Energy and Westar that was used in connection with Great Plains Energy's and Westar's special shareholder meetings on November 21, 2017, and the registration of shares of Holdco common stock to be issued to Great Plains Energy's and Westar's shareholders at the closing of the anticipated merger. In November 2017, Great Plains Energy and Westar filed their respective Pre-Merger Notification and Report forms with the Federal Trade Commission (FTC) and the Department of Justice (DOJ) under the Hart-Scott-Rodino (HSR) Act. In December 2017, the FTC granted Great Plains Energy's request for early termination of the waiting period under the HSR Act with respect to the anticipated merger. In February 2018, Great Plains Energy, KCP&L, GMO and Westar filed Transfer of Control applications with FCC.

Termination Fees
The Amended Merger Agreement provides that in connection with a termination of the agreement under specified circumstances relating to a failure to obtain regulatory approvals by July 9, 2018 (which date may be extended to January 9, 2019), a final and nonappealable order enjoining the consummation of the anticipated merger in connection with regulatory approvals or failure by Great Plains Energy to comply with its obligations under the

Amended Merger Agreement to consummate the closing of the anticipated merger once all of the conditions have been satisfied, Great Plains Energy may be required to pay Westar a termination fee of $190 million. In addition, in the event that the Amended Merger Agreement is terminated by Westar under certain circumstances to enter into a definitive acquisition agreement with respect to a superior proposal, Westar may be required to pay Great Plains Energy a termination fee of $190 million. Similarly, in the event that the Amended Merger Agreement is terminated by Great Plains Energy under certain circumstances to enter into a definitive acquisition agreement with respect to a superior proposal, Great Plains Energy may be required to pay Westar a termination fee of $190 million.

Shareholder Lawsuits
Following the announcement of the Original Merger Agreement in May 2016, two putative class action complaints (which were consolidated and superseded by a consolidated complaint) were filed in the District Court of Shawnee County, Kansas. On October 20, 2017, the lead plaintiff in that consolidated putative class action filed an amended class action petition. The amended petition named as defendants Westar, the Westar Board, Great Plains Energy, Holdco and Merger Sub. The amended petition challenged the proposed merger and alleged breaches of fiduciary duties against the Westar Board in connection with the proposed merger, including the duty of candor, and that Westar, Great Plains Energy, Holdco and Merger Sub aided and abetted such breaches of fiduciary duties.

On September 21, 2017, a putative class action lawsuit was filed in the U.S. District Court for the District of Kansas. The federal class action complaint named as defendants Westar, the Westar Board, Great Plains Energy, Holdco and Merger Sub. The complaint challenged the merger and alleged violations of section 14(a) of the Securities Exchange Act of 1934, as amended (“Exchange Act”) against all of the defendants and violations of section 20(a) of the Exchange Act against the Westar Board.

On October 6, 2017, a putative class action lawsuit was filed in the U.S. District Court for the District of Kansas. The federal class action complaint named as defendants Westar, the Westar Board, Great Plains Energy, Holdco and Merger Sub. The complaint challenged the proposed merger and alleged violations of section 14(a) of the Exchange Act against Westar and the Westar Board and violations of section 20(a) of the Exchange Act against the Westar Board, Great Plains Energy, Holdco and Merger Sub.

On October 13, 2017, a putative class action lawsuit was filed in the U.S. District Court for the Western District of Missouri, Western Division. The federal class action complaint named as defendants Great Plains Energy and the Great Plains Energy Board. The complaint challenged the proposed merger and alleged violations of section 14(a) of the Exchange Act against all of the defendants and violations of section 20(a) of the Exchange Act against the Great Plains Energy Board.

On October 18, 2017, a putative derivative complaint was filed in Shawnee County, Kansas. This putative derivative action named as defendants the Westar Board, Great Plains Energy, Holdco and Merger Sub, with Westar named as a nominal defendant. The complaint challenged the proposed merger and alleged that the Westar Board determined to forego a $380 million break-up fee allegedly payable to Westar associated with the Original Merger Agreement, breached their fiduciary duties to Westar shareholders in connection with the proposed merger, and that Great Plains Energy, Holdco and Merger Sub aided and abetted such breaches of fiduciary duties.

On November 16, 2017, the plaintiffs in these lawsuits agreed in principle to dismiss the lawsuits and, in exchange, Great Plains Energy, Westar Energy and Holdco agreed, solely in order to avoid the risk that litigation might delay or otherwise adversely affect the consummation of the proposed merger under the Amended Merger Agreement and to minimize the expense of defending such actions, to make supplemental disclosures to the Joint Proxy Statement/Prospectus, which were made on Forms 8-K dated November 16, 2017. The lawsuits have been dismissed. These dismissals do not release or otherwise prejudice any potential claims of any member of the putative class, other than for the plaintiffs in these lawsuits, and do not constitute any admission by any of the defendants as to the merits of any claims.

Redemption of Acquisition Financing
In order to fund the cash portion of the acquisition under the Original Merger Agreement, Great Plains Energy completed registered public offerings of 60.5 million shares of common stock for total net proceeds of $1.55 billion

and 17.3 million depositary shares each representing a 1/20th interest in a share of Series B Preferred Stock for total net proceeds of $836.2 million in October 2016 and issued, at a discount, $4.3 billion of senior notes in March 2017. Great Plains Energy also entered into a stock purchase agreement with OMERS, pursuant to which Great Plains Energy would issue and sell to OMERS 750,000 shares of preferred stock of Great Plains Energy designated as 7.25% Mandatory Convertible Preferred Stock, Series A (Series A Preferred Stock), without par value, for an aggregate purchase price equal to $750 million at the closing of the acquisition.

In addition to the financings discussed above, Great Plains Energy also entered into a senior unsecured bridge term loan facility in connection with the Original Merger Agreement in an aggregate principal amount of $8.017 billion (which was subsequently reduced to $864.5 million as a result of the completed financings noted above) to support the anticipated transaction and provide flexibility for the timing of long-term financing.

As a result of the Amended Merger Agreement, the following occurred with regards to Great Plains Energy's acquisition financing arrangements:

- In July 2017, Great Plains Energy redeemed its $4.3 billion of senior notes at a redemption price of 101% of the aggregate principle amount, plus accrued and unpaid interest. See Note 12 for additional information;
- In August 2017, Great Plains Energy redeemed its Series B Preferred Stock at a redemption price that was equal to a make-whole formula set forth in the terms of the Series B Preferred Stock. See Note 14 for additional information;
- In July 2017, Great Plains Energy and OMERS terminated their stock purchase agreement for $750 million of Series A Preferred Stock. As a result of this termination, Great Plains Energy recorded $15 million of previously deferred offering fees to non-operating expenses in the third quarter of 2017; and
- In July 2017, Great Plains Energy terminated its $864.5 million unsecured bridge term loan facility.

Under the Amended Merger Agreement, Great Plains Energy is required to have not less than $1.25 billion in cash and cash equivalents on its balance sheet at the closing of the anticipated merger with Westar. It is expected that this excess cash will be returned to shareholders of the combined company through the repurchase of common stock over time after the closing of the anticipated merger.

3. SUPPLEMENTAL CASH FLOW INFORMATION

Great Plains Energy Other Operating Activities

Year Ended December 31	**2017**	**2016**	**2015**
Cash flows affected by changes in:		(millions)	
Receivables	$ 14.8	$ (18.3)	$ 12.5
Accounts receivable pledged as collateral	(7.6)	2.6	(4.0)
Fuel inventories	5.6	9.6	(28.3)
Materials and supplies	(9.0)	(6.5)	(3.0)
Accounts payable	9.0	(25.4)	(11.4)
Accrued taxes	1.5	8.1	1.1
Accrued interest	(8.0)	6.1	3.4
Deferred refueling outage costs	15.5	(3.1)	(6.7)
Pension and post-retirement benefit obligations	26.1	27.4	18.5
Allowance for equity funds used during construction	(6.0)	(6.6)	(4.8)
Fuel recovery mechanisms	(11.4)	(46.9)	47.5
ARO settlements	(28.5)	(17.4)	(4.1)
Other	20.6	28.1	(7.8)
Total other operating activities	$ 22.6	$ (42.3)	$ 12.9
Cash paid during the period:			
Interest	$ 258.9	$ 191.2	$ 182.2
Income taxes	$ —	$ 0.1	$ 0.1
Non-cash investing activities:			
Liabilities accrued for capital expenditures	$ 39.8	$ 32.4	$ 35.7

KCP&L Other Operating Activities

Year Ended December 31	**2017**	**2016**	**2015**
Cash flows affected by changes in:		(millions)	
Receivables	$ 13.8	$ (12.4)	$ 2.6
Accounts receivable pledged as collateral	(20.0)	—	—
Fuel inventories	1.9	10.6	(24.7)
Materials and supplies	(7.1)	(4.3)	(4.5)
Accounts payable	11.7	(30.5)	(18.0)
Accrued taxes	9.1	67.9	(19.0)
Accrued interest	—	—	3.4
Deferred refueling outage costs	15.5	(3.1)	(6.7)
Pension and post-retirement benefit obligations	27.3	28.6	18.4
Allowance for equity funds used during construction	(6.0)	(6.6)	(3.8)
Fuel recovery mechanisms	8.3	(53.7)	3.5
ARO settlements	(25.5)	(15.0)	(4.1)
Other	(9.0)	16.4	(8.6)
Total other operating activities	$ 20.0	$ (2.1)	$ (61.5)
Cash paid during the period:			
Interest	$ 128.0	$ 127.0	$ 120.2
Income taxes	$ 38.8	$ —	$ —
Non-cash investing activities:			
Liabilities accrued for capital expenditures	$ 32.9	$ 27.2	$ 23.9

4. RECEIVABLES

Great Plains Energy's and KCP&L's receivables are detailed in the following table.

	December 31 2017	December 31 2016
Great Plains Energy	(millions)	
Customer accounts receivable - billed	$ 3.7	$ 26.2
Customer accounts receivable - unbilled	103.2	79.1
Allowance for doubtful accounts - customer accounts receivable	(4.7)	(4.0)
Other receivables	49.5	64.7
Total	$ 151.7	$ 166.0
KCP&L		
Customer accounts receivable - billed	$ 1.6	$ 25.5
Customer accounts receivable - unbilled	67.6	63.7
Allowance for doubtful accounts - customer accounts receivable	(2.2)	(1.8)
Other receivables	39.3	51.7
Total	$ 106.3	$ 139.1

Great Plains Energy's and KCP&L's other receivables at December 31, 2017 and 2016, consisted primarily of receivables from partners in jointly owned electric utility plants and wholesale sales receivables.

Sale of Accounts Receivable – KCP&L and GMO

KCP&L and GMO sell all of their retail electric accounts receivable to their wholly owned subsidiaries, KCP&L Receivables Company and GMO Receivables Company, respectively, which in turn sell an undivided percentage ownership interest in the accounts receivable to Victory Receivables Corporation, an independent outside investor. Each of KCP&L Receivables Company's and GMO Receivables Company's sale of the undivided percentage ownership interest in accounts receivable to Victory Receivables Corporation is accounted for as a secured borrowing with accounts receivable pledged as collateral and a corresponding short-term collateralized note payable recognized on the balance sheets. At December 31, 2017 and 2016, Great Plains Energy's accounts receivable pledged as collateral and the corresponding short-term collateralized note payable were $180.0 million and $172.4 million, respectively. At December 31, 2017 and 2016, KCP&L's accounts receivable pledged as collateral and the corresponding short-term collateralized note payable were $130.0 million and $110.0 million, respectively. In September 2017, KCP&L and GMO amended their respective receivable sale agreements with Victory Receivables Corporation to extend the termination date to September 2018 and to allow for $130 million in aggregate outstanding principal amount of borrowings at any time for KCP&L and $50 million in aggregate outstanding principal amount of borrowings from mid-November through mid-June and then $65 million from mid-June through mid-November for GMO.

5. NUCLEAR PLANT

KCP&L owns 47% of Wolf Creek, its only nuclear generating unit. Wolf Creek is located in Coffey County, Kansas, just northeast of Burlington, Kansas. Wolf Creek's operating license expires in 2045. Wolf Creek is regulated by the NRC with respect to licensing, operations and safety-related requirements.

Spent Nuclear Fuel and High-Level Radioactive Waste

Under the Nuclear Waste Policy Act of 1982, the Department of Energy (DOE) is responsible for the permanent disposal of spent nuclear fuel. Wolf Creek historically paid the DOE a quarterly fee of one-tenth of a cent for each kWh of net nuclear generation delivered and sold for the future disposal of spent nuclear fuel. In May 2014, this fee was set to zero.

In 2010, the DOE filed a motion with the NRC to withdraw its then pending application to the NRC 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. In 2011, the NRC announced that it was evenly divided on whether to take affirmative action to overturn or uphold the board's decision and ordered the licensing board, consistent with budgetary limitations, to close out its work on the DOE's application. In August 2013, a federal court of appeals ruled that the NRC must resume its review of the DOE's application to the extent of appropriated funds. With the available funds, the NRC was able to complete its technical review of the Yucca Mountain application but was not able to resume the licensing hearing.

Wolf Creek is currently evaluating alternatives for expanding its existing on-site spent nuclear fuel storage to provide additional capacity prior to 2025. Management 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.

Low-Level Radioactive Waste

Wolf Creek disposes of most of its low-level radioactive waste (Class A waste) at an existing third-party repository in Utah. Management expects that the site located in Utah will remain available to Wolf Creek for disposal of its Class A waste. Wolf Creek has contracted with a waste processor that will process, take title and dispose in another state most of the remainder of Wolf Creek's low-level radioactive waste (Classes B and C waste, which is higher in radioactivity but much lower in volume). Should on-site waste storage be needed in the future, Wolf Creek has current storage capacity on site for about four years' generation of Classes B and C waste and believes it will be able to expand that storage capacity as needed if it becomes necessary to do so.

Nuclear Plant Decommissioning Costs

The MPSC and KCC require KCP&L and the other owners of Wolf Creek to submit an updated decommissioning cost study every three years and to propose funding levels. The most recent study was submitted to the MPSC and KCC in September 2017 and is the basis for the current cost of decommissioning estimates in the following table. Funding levels included in KCP&L retail rates have not changed. The actual nuclear decommissioning costs may vary from these estimates because of changes in regulations and technologies as well as changes in costs for labor, materials and equipment.

	KCC	MPSC
	(millions)	
Current cost of decommissioning (in 2017 dollars)		
Total Station	$ 813.7	$ 813.7
KCP&L's 47% Share	382.5	382.5
Future cost of decommissioning (in 2045-2053 dollars) [a]		
Total Station	$ 1,982.4	$ 2,137.8
KCP&L's 47% Share	931.7	1,004.8
Annual escalation factor	2.91%	3.16%
Annual return on trust assets [b]	5.64%	5.46%

[a]Total future cost over an eight year decommissioning period

[b]The 5.64% KCC rate of return is through 2029 and then systematically decreases through 2053 to 0.32%. The 5.46% MPSC rate of return is through 2027 and then systematically decreases through 2053 to 2.22%. The KCC and MPSC rates of return systematically decrease based on the assumption that the fund's investment mix will become increasingly conservative as the decommissioning period approaches.

Nuclear Decommissioning Trust Fund
In 2017 and 2016, KCP&L contributed approximately $3.3 million to a tax-qualified trust fund to be used to decommission Wolf Creek. Amounts funded are charged to other operating expense and recovered in customers' rates. The funding level assumes a projected level of return on trust assets. If the actual return on trust assets is below the projected level or actual decommissioning costs are higher than estimated, KCP&L could be responsible for the balance of funds required; however, while there can be no assurances, management believes a rate increase would be allowed to recover decommissioning costs over the remaining life of the unit.

The following table summarizes the change in Great Plains Energy's and KCP&L's nuclear decommissioning trust fund.

	2017	2016
Decommissioning Trust	(millions)	
Beginning balance January 1	$ 222.9	$ 200.7
Contributions	3.3	3.3
Earned income, net of fees	4.3	4.1
Net realized gains	0.7	0.3
Net unrealized gains	27.2	14.5
Ending balance December 31	$ 258.4	$ 222.9

The nuclear decommissioning trust is reported at fair value on the balance sheets and is invested in assets as detailed in the following table.

	December 31							
	2017				2016			
	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
	(millions)							
Equity securities	$ 96.5	$ 88.3	$ (1.0)	$ 183.8	$ 93.3	$ 62.1	$ (1.5)	$ 153.9
Debt securities	69.7	2.7	(0.4)	72.0	63.4	2.3	(0.5)	65.2
Other	2.6	—	—	2.6	3.8	—	—	3.8
Total	$ 168.8	$ 91.0	$ (1.4)	$ 258.4	$ 160.5	$ 64.4	$ (2.0)	$ 222.9

The weighted average maturity of debt securities held by the trust at December 31, 2017, was approximately 9 years. The costs of securities sold are determined on the basis of specific identification. The following table summarizes the realized gains and losses from the sale of securities in the nuclear decommissioning trust fund.

	2017	2016	2015
		(millions)	
Realized gains	$ 2.5	$ 1.6	$ 5.3
Realized losses	(1.8)	(1.3)	(4.6)

Nuclear Insurance
The owners of Wolf Creek (Owners) maintain nuclear insurance for Wolf Creek for nuclear liability, nuclear property and accidental outage. These policies contain certain industry standard exclusions, including, but not limited to, ordinary wear and tear, and war. The nuclear property insurance programs subscribed to by members of the nuclear power generating industry include industry aggregate limits for acts of terrorism and related losses, including replacement power costs. There is no industry aggregate limit for liability claims related to terrorism, regardless of the number of acts of terrorism affecting Wolf Creek or any other nuclear energy liability policy or the number of policies in place. An industry aggregate limit of $3.2 billion plus any reinsurance recoverable by Nuclear Electric Insurance Limited (NEIL), the Owners' insurance provider, exists for property claims related to nuclear acts of terrorism, including accidental outage power costs for nuclear acts of terrorism affecting Wolf Creek or any other nuclear energy facility property policy within twelve months from the date of the first act. An industry

aggregate limit of $1.8 billion exists for property claims related to non-nuclear acts of terrorism. These limits plus any recoverable reinsurance are the maximum amount to be paid to members who sustain losses or damages from these types of terrorist acts. In addition, industry-wide retrospective assessment programs (discussed below) can apply once these insurance programs have been exhausted.

In the event of a catastrophic loss at Wolf Creek, the insurance coverage may not be adequate to cover property damage and extra expenses incurred. Uninsured losses, to the extent not recovered through rates, would be assumed by KCP&L and the other owners and could have a material effect on Great Plains Energy's and KCP&L's results of operations, financial position and cash flows.

Nuclear Liability Insurance

Pursuant to the Price-Anderson Act, which was reauthorized through December 31, 2025, by the Energy Policy Act of 2005, the Owners are required to insure against public liability claims resulting from nuclear incidents to the full limit of public liability, which is currently $13.5 billion. This limit of liability consists of the maximum available commercial insurance of $0.5 billion and the remaining $13.0 billion is provided through an industry-wide retrospective assessment program mandated by law, known as the Secondary Financial Protection (SFP) program. Under the SFP program, the Owners can be assessed up to $127.3 million ($59.8 million, KCP&L's 47% share) per incident at any commercial reactor in the country, payable at no more than $19.0 million ($8.9 million, KCP&L's 47% share) per incident per year. This assessment is subject to an inflation adjustment based on the Consumer Price Index and applicable premium taxes. In addition, the U.S. Congress could impose additional revenue-raising measures to pay claims.

Nuclear Property Insurance

The Owners carry decontamination liability, premature decommissioning liability and property damage insurance from NEIL for Wolf Creek totaling approximately $2.8 billion ($1.3 billion, KCP&L's 47% share). In the event of an accident, insurance proceeds must first be used for reactor stabilization and site decontamination in accordance with a plan mandated by the NRC. KCP&L's share of any remaining proceeds can be used for further decontamination, property damage restoration and premature decommissioning costs. Premature decommissioning coverage applies only if an accident at Wolf Creek exceeds $500 million in property damage and decontamination expenses, and only after trust funds have been exhausted.

Accidental Nuclear Outage Insurance

The Owners also carry additional insurance from NEIL to cover costs of replacement power and other extra expenses incurred in the event of a prolonged outage resulting from accidental property damage at Wolf Creek.

Under all NEIL policies, the Owners are subject to retrospective assessments if NEIL losses, for each policy year, exceed the accumulated funds available to the insurer under that policy. The estimated maximum amount of retrospective assessments under the current policies could total approximately $37.4 million ($17.6 million, KCP&L's 47% share) per policy year.

6. REGULATORY MATTERS

KCP&L Missouri 2018 Rate Case Proceedings

In January 2018, KCP&L filed an application with the MPSC to request an increase to its retail revenues of $8.9 million before rebasing fuel and purchased power expense, with a return on equity of 9.85% and a rate-making equity ratio of 50.03%. The request reflects the impact of the Tax Cut and Jobs Act and increases in infrastructure investment costs, transmission related costs and property tax costs. KCP&L also requested an additional $7.5 million increase associated with rebasing fuel and purchased power expense.

GMO Missouri 2018 Rate Case Proceedings

In January 2018, GMO filed an application with the MPSC to request a decrease to its retail revenues of $2.4 million before rebasing fuel and purchased power expense, with a return on equity of 9.85% and a rate-making equity ratio of 54.4%. The request reflects the impact of the Tax Cut and Jobs Act and increases in infrastructure investment costs and transmission related costs. GMO also requested a $21.7 million increase associated with rebasing fuel and purchased power expense.

KCP&L Kansas 2016 Abbreviated Rate Case Proceedings

In November 2016, KCP&L filed an abbreviated application with KCC to request a decrease to its retail revenues of $2.8 million, reflecting the true-up to actuals of construction and environmental upgrade costs at the La Cygne Station and Wolf Creek capital addition costs and the removal of certain regulatory asset and liability amortizations. The previously approved return on equity and rate-making ratio for KCP&L was not addressed in this case. In April 2017, KCP&L, KCC staff and the Citizens' Utility Ratepayer Board filed a joint motion to approve a unanimous settlement agreement with KCC that requested a decrease in retail revenues of $3.6 million. In June 2017, KCC issued an order approving the unanimous settlement agreement. The rates established by the order took effect on June 28, 2017.

KCP&L Missouri 2016 Rate Case Proceedings

In July 2016, KCP&L filed an application with the MPSC to request an increase to its retail revenues of $62.9 million before rebasing fuel and purchased power expense, with a return on equity of 9.9% and a rate-making equity ratio of 49.88%. The request reflects increases in infrastructure investment costs, costs for regional transmission lines, property tax costs and costs to comply with environmental and cybersecurity mandates. KCP&L also requested an additional $27.2 million increase associated with rebasing fuel and purchased power expense.

In May 2017, the MPSC issued an order for KCP&L authorizing an increase in retail revenues of $5.4 million before rebasing fuel and purchased power expense, a return on equity of 9.5% and a rate-making equity ratio of approximately 49.2%. The order also authorized a $27.1 million revenue increase associated with rebasing fuel and purchased power expense. The rates established by the order took effect on June 8, 2017.

Regulatory Assets and Liabilities

Great Plains Energy and KCP&L have recorded assets and liabilities on their consolidated balance sheets resulting from the effects of the ratemaking process, which would not otherwise be recorded if the Companies were not regulated. Regulatory assets represent incurred costs that are probable of recovery from future revenues. Regulatory liabilities represent future reductions in revenues or refunds to customers.

Management regularly assesses whether regulatory assets and liabilities are probable of future recovery or refund by considering factors such as decisions by the MPSC, KCC or FERC in KCP&L's and GMO's rate case filings; decisions in other regulatory proceedings, including decisions related to other companies that establish precedent on matters applicable to the Companies; and changes in laws and regulations. If recovery or refund of regulatory assets or liabilities is not approved by regulators or is no longer deemed probable, these regulatory assets or liabilities are recognized in the current period results of operations. The Companies' continued ability to meet the criteria for recording regulatory assets and liabilities may be affected in the future by restructuring and deregulation in the electric industry or changes in accounting rules. In the event that the criteria no longer applied to any or all of the Companies' operations, the related regulatory assets and liabilities would be written off unless an appropriate regulatory recovery mechanism were provided. Additionally, these factors could result in an impairment on utility plant assets.

Great Plains Energy's and KCP&L's regulatory assets and liabilities are detailed in the following table.

	December 31					
	2017			2016		
	KCP&L	GMO	Great Plains Energy	KCP&L	GMO	Great Plains Energy
Regulatory Assets	(millions)					
Taxes recoverable through future rates	$ —	$ —	$ —	$ 123.9	$ 24.8	$ 148.7
Loss on reacquired debt	8.7 [(a)]	1.2 [(a)]	9.9	10.0	1.7	11.7
Cost of removal	30.3	—	30.3	28.6	—	28.6
Asset retirement obligations	94.3	24.2	118.5	69.6	24.9	94.5
Pension and post-retirement costs	379.7 [(b)]	108.2 [(b)]	487.9	367.9	104.7	472.6
Deferred customer programs	40.9 [(c)]	19.4 [(d)]	60.3	45.9	27.4	73.3
Fuel recovery mechanism	61.7 [(e)]	12.0 [(e)]	73.7	69.9	—	69.9
Iatan No. 1 and common facilities depreciation and carrying costs	12.9 [(f)]	4.7 [(g)]	17.6	13.6	5.0	18.6
Iatan No. 2 construction accounting costs	25.0 [(h)]	13.7 [(h)]	38.7	26.9	16.1	43.0
Kansas property tax surcharge	6.6 [(e)]	—	6.6	3.6	—	3.6
Solar rebates	22.6 [(i)]	37.0 [(e)]	59.6	29.2	41.6	70.8
Transmission delivery charge	3.2 [(e)]	—	3.2	3.1	—	3.1
La Cygne deferred depreciation	2.7 [(j)]	—	2.7	2.8	—	2.8
Other	3.3 [(e)]	1.6	4.9	6.8	—	6.8
Total	$ 691.9	$ 222.0	$ 913.9	$ 801.8	$ 246.2	$ 1,048.0
Regulatory Liabilities						
Taxes refundable through future rates	$ 574.0	$ 220.6	$ 794.6	$ —	$ —	$ —
Emission allowances	58.1	—	58.1	62.1	—	62.1
Asset retirement obligations	126.0	—	126.0	99.7	—	99.7
Cost of removal	—	57.4	57.4	—	65.1	65.1
Fuel recovery mechanism	—	3.9	3.9	—	11.6	11.6
Pension and post-retirement costs	12.0	8.2	20.2	15.3	7.4	22.7
Other	9.1	37.0	46.1	10.3	38.4	48.7
Total	$ 779.2	$ 327.1	$ 1,106.3	$ 187.4	$ 122.5	$ 309.9

(a) Amortized over the life of the related new debt issuances or the remaining lives of the old debt issuances if no new debt was issued.
(b) Represents unrecognized gains and losses, prior service and transition costs that will be recognized in future net periodic pension and post-retirement costs, pension settlements amortized over various periods and financial and regulatory accounting method differences that will be eliminated over the life of the pension plans. Of these amounts, $366.3 million and $61.4 million for KCP&L and GMO, respectively, are not included in rate base and are amortized over various periods.
(c) $16.1 million not included in rate base and amortized over various periods.
(d) $10.9 million not included in rate base and amortized over various periods.
(e) Not included in rate base and amortized over various periods.
(f) Included in rate base and amortized over various periods.
(g) Included in rate base and amortized through 2038.
(h) Included in rate base and amortized through 2059.
(i) Not included in rate base and amortized through 2020.
(j) Included in rate base and amortized through 2040.

7. GOODWILL AND INTANGIBLE ASSETS

Accounting rules require goodwill to be tested for impairment annually and when an event occurs indicating the possibility that an impairment exists. The annual impairment test for the $169.0 million of GMO acquisition goodwill was conducted on September 1, 2017. The goodwill impairment test consists of comparing the fair value of a reporting unit to its carrying amount, including goodwill, to identify potential impairment. In the event that the carrying amount exceeds the fair value of the reporting unit, an impairment loss is recognized for the difference between the carrying amount of the reporting unit and its fair value. Great Plains Energy's regulated electric utility operations are considered one reporting unit for assessment of impairment, as they are included within the same operating segment and have similar economic characteristics. The determination of fair value of the reporting unit consisted of two valuation techniques: an income approach consisting of a discounted cash flow analysis and a market approach consisting of a determination of reporting unit invested capital using market multiples derived from the historical revenue; earnings before interest, income taxes, depreciation and amortization; net utility asset values and market prices of stock of peer companies. The results of the two techniques were evaluated and weighted to determine a point within the range that management considered representative of fair value for the reporting unit. Fair value of the reporting unit exceeded the carrying amount, including goodwill; therefore, there was no impairment of goodwill.

Great Plains Energy's and KCP&L's intangible assets are included in electric utility plant on the consolidated balance sheets and are detailed in the following table.

	December 31			
	2017		2016	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Great Plains Energy	(millions)			
Computer software	$ 386.8	$ (251.2)	$ 355.2	$ (219.1)
Asset improvements	30.3	(8.0)	28.8	(6.7)
KCP&L				
Computer software	$ 368.7	$ (234.3)	$ 338.3	$ (203.1)
Asset improvements	15.1	(2.7)	13.6	(1.8)

Great Plains Energy's and KCP&L's amortization expense related to intangible assets is detailed in the following table.

	2017	2016
	(millions)	
Great Plains Energy	$ 33.7	$ 29.1
KCP&L	32.1	25.7

The following table provides the estimated amortization expense related to Great Plains Energy's and KCP&L's intangible assets for 2018 through 2022 for the intangible assets included in the consolidated balance sheets at December 31, 2017.

	2018	2019	2020	2021	2022
			(millions)		
Great Plains Energy	$ 30.5	$ 25.7	$ 24.5	$ 20.0	$ 14.9
KCP&L	29.7	25.0	23.8	19.5	14.5

8. ASSET RETIREMENT OBLIGATIONS

AROs associated with tangible long-lived assets are legal obligations that exist under enacted laws, statutes and written or oral contracts, including obligations arising under the doctrine of promissory estoppel. These liabilities are recognized at estimated fair value as incurred with a corresponding amount capitalized as part of the cost of the related long-lived assets and depreciated over their useful lives. Accretion of the liabilities due to the passage of time is recorded to a regulatory asset and/or liability. Changes in the estimated fair values of the liabilities are recognized when known. Great Plains Energy and KCP&L record the current portion of AROs within other current liabilities on their consolidated balance sheets.

KCP&L has AROs related to decommissioning Wolf Creek, site remediation of its Spearville Wind Energy Facilities, asbestos abatement, removal of storage tanks and closure and post-closure of ponds and landfills containing coal combustion residuals (CCRs). GMO has AROs related to asbestos abatement, removal of storage tanks and closure and post-closure of ponds and landfills containing CCRs.

Additionally, certain wiring used in Great Plains Energy's and KCP&L's generating stations include asbestos insulation, which would require special handling if disturbed. Due to the inability to reasonably estimate the quantities or the amount of disturbance that will be necessary during dismantlement at the end of the life of a plant, the fair value of this ARO cannot be reasonably estimated at this time. Management will continue to monitor the obligation and will recognize a liability in the period in which sufficient information becomes available to reasonably estimate its fair value.

On April 17, 2015, the Environmental Protection Agency (EPA) published new regulations to regulate the disposal of CCRs at electric generation facilities. The CCR rule represents legal obligations of Great Plains Energy and KCP&L as to the closure and post-closure of its ponds and landfills containing CCRs. In 2016, Great Plains Energy and KCP&L revised their AROs by $42.1 million and $40.1 million, respectively, due to an increase in cost estimates for the closure of ponds and landfills containing CCRs at KCP&L's electric generating facilities.

The following table summarizes the change in Great Plains Energy's and KCP&L's AROs.

	Great Plains Energy		KCP&L	
	2017	2016	2017	2016
	(millions)			
Beginning balance	$ 316.0	$ 275.9	$ 278.0	$ 239.3
Additions	—	1.6	—	1.3
Revision in timing and/or estimates	(1.3)	42.1	0.3	40.1
Settlements	(28.5)	(17.4)	(25.5)	(15.0)
Accretion	14.9	13.8	13.5	12.3
Total	$ 301.1	$ 316.0	$ 266.3	$ 278.0
Less: current portion	(38.6)	—	(34.9)	—
Total noncurrent asset retirement obligation	$ 262.5	$ 316.0	$ 231.4	$ 278.0

ARO settlement activity in 2017 and 2016 primarily consists of the remediation of AROs for the closure of ponds and landfills containing CCRs at KCP&L and GMO.

9. PENSION PLANS AND OTHER EMPLOYEE BENEFITS

Great Plains Energy maintains defined benefit pension plans for the majority of KCP&L's and GMO's active and inactive employees, including officers, and its 47% ownership share of Wolf Creek Nuclear Operating Corporation (WCNOC) defined benefit plans. For the majority of employees, pension benefits under these plans reflect the employees' compensation, years of service and age at retirement. Effective in 2014, Great Plains Energy's non-union plan was closed to future employees. Great Plains Energy also provides certain post-retirement health care and life insurance benefits for substantially all retired employees of KCP&L, GMO and its 47% ownership share of WCNOC.

KCP&L and GMO record pension and post-retirement expense in accordance with rate orders from the MPSC and KCC that allow the difference between pension and post-retirement costs under GAAP and costs for ratemaking to be recognized as a regulatory asset or liability. This difference between financial and regulatory accounting methods is due to timing and will be eliminated over the life of the plans.

In 2017, Great Plains Energy incurred pension settlement charges of $15.9 million as a result of accelerated pension distributions.

The following pension benefits tables provide information relating to the funded status of all defined benefit pension plans on an aggregate basis as well as the components of net periodic benefit costs. For financial reporting purposes, the market value of plan assets is the fair value. For regulatory reporting purposes, a five-year smoothing of assets is used to determine fair value. Net periodic benefit costs reflect total plan benefit costs prior to the effects of capitalization and sharing with joint owners of power plants.

	Pension Benefits		Other Benefits	
	2017	**2016**	**2017**	**2016**
Change in projected benefit obligation (PBO)		(millions)		
PBO at January 1	$ 1,244.6	$ 1,154.8	$ 130.1	$ 137.5
Service cost	44.2	42.0	2.1	2.6
Interest cost	53.5	52.9	5.4	6.1
Contribution by participants	—	—	6.0	5.3
Amendments	—	—	—	(10.1)
Actuarial (gain) loss	135.6	65.5	2.1	0.6
Benefits paid	(36.8)	(70.6)	(12.5)	(11.9)
Settlements and special termination benefits	(85.2)	—	—	—
PBO at December 31	$ 1,355.9	$ 1,244.6	$ 133.2	$ 130.1
Change in plan assets				
Fair value of plan assets at January 1	$ 776.8	$ 723.9	$ 115.6	$ 114.3
Actual return on plan assets	114.8	51.1	1.8	2.6
Contributions by employer and participants	76.9	69.8	10.4	10.2
Benefits paid	(34.5)	(68.0)	(12.0)	(11.5)
Settlements	(85.6)	—	—	—
Fair value of plan assets at December 31	$ 848.4	$ 776.8	$ 115.8	$ 115.6
Funded status at December 31	$ (507.5)	$ (467.8)	$ (17.4)	$ (14.5)
Amounts recognized in the consolidated balance sheets				
Non-current asset	$ —	$ —	$ 12.8	$ 9.0
Current pension and other post-retirement liability	(1.9)	(2.2)	(0.8)	(0.8)
Noncurrent pension liability and other post-retirement liability	(505.6)	(465.6)	(29.4)	(22.7)
Net amount recognized before regulatory treatment	(507.5)	(467.8)	(17.4)	(14.5)
Accumulated OCI or regulatory asset/liability	492.2	476.9	(21.1)	(23.6)
Net amount recognized at December 31	$ (15.3)	$ 9.1	$ (38.5)	$ (38.1)
Amounts in accumulated OCI or regulatory asset/liability not yet recognized as a component of net periodic benefit cost:				
Actuarial (gain) loss	$ 248.9	$ 242.5	$ 2.8	$ (0.7)
Prior service cost	2.5	3.2	(8.0)	(8.0)
Other	240.8	231.2	(15.9)	(14.9)
Net amount recognized at December 31	$ 492.2	$ 476.9	$ (21.1)	$ (23.6)

	Pension Benefits			Other Benefits		
	2017	2016	2015	2017	2016	2015
Components of net periodic benefit costs			(millions)			
Service cost	$ 44.2	$ 42.0	$ 45.3	$ 2.1	$ 2.6	$ 3.3
Interest cost	53.5	52.9	50.3	5.4	6.1	6.8
Expected return on plan assets	(51.2)	(49.2)	(51.7)	(2.6)	(3.1)	(2.9)
Prior service cost	0.7	0.7	0.8	—	1.2	3.1
Recognized net actuarial (gain) loss	49.7	51.8	51.4	(0.5)	(1.5)	0.2
Transition obligation	—	—	—	—	—	0.2
Settlement and special termination benefits	16.3	—	—	—	—	—
Net periodic benefit costs before regulatory adjustment	113.2	98.2	96.1	4.4	5.3	10.7
Regulatory adjustment	(13.8)	(4.9)	(9.8)	1.9	6.0	4.4
Net periodic benefit costs	99.4	93.3	86.3	6.3	11.3	15.1
Other changes in plan assets and benefit obligations recognized in OCI or regulatory assets/liabilities						
Current year net (gain) loss	72.0	63.6	8.6	3.0	1.1	(20.6)
Amortization of gain (loss)	(65.6)	(51.8)	(51.4)	0.5	1.5	(0.2)
Prior service cost	—	—	—	—	(10.2)	(7.0)
Amortization of prior service cost	(0.7)	(0.7)	(0.8)	—	(1.2)	(3.1)
Amortization of transition obligation	—	—	—	—	—	(0.2)
Other regulatory activity	9.6	4.6	4.3	(1.0)	(5.4)	(4.4)
Total recognized in OCI or regulatory asset/ liability	15.3	15.7	(39.3)	2.5	(14.2)	(35.5)
Total recognized in net periodic benefit costs and OCI or regulatory asset/liability	$ 114.7	$ 109.0	$ 47.0	$ 8.8	$ (2.9)	$ (20.4)

For financial reporting purposes, the estimated prior service cost and net loss for the defined benefit plans that will be amortized from accumulated other comprehensive income (OCI) or a regulatory asset into net periodic benefit cost in 2018 are $0.7 million and $45.7 million, respectively. For financial reporting purposes, net actuarial gains and losses are recognized on a rolling five-year average basis. For regulatory reporting purposes, net actuarial gains and losses are amortized over ten years. The estimated net gain for the other post-retirement benefit plans that will be amortized from accumulated OCI or a regulatory asset into net periodic benefit cost in 2018 is $0.2 million.

The accumulated benefit obligation (ABO) for all defined benefit pension plans was $1,169.8 million and $1,090.2 million at December 31, 2017, and 2016, respectively. Pension and other post-retirement benefit plans with the PBO, ABO or accumulated other post-retirement benefit obligation (APBO) in excess of the fair value of plan assets at year-end are detailed in the following table.

	2017	2016
Pension plans with the PBO in excess of plan assets	(millions)	
Projected benefit obligation	$ 1,355.9	$ 1,244.6
Fair value of plan assets	848.4	776.8
Pension plans with the ABO in excess of plan assets		
Accumulated benefit obligation	$ 1,169.8	$ 1,090.2
Fair value of plan assets	848.4	776.8
Other post-retirement benefit plans with the APBO in excess of plan assets		
Accumulated other post-retirement benefit obligation	$ 111.6	$ 61.7
Fair value of plan assets	81.5	38.3

The GMO Supplemental Executive Retirement Plan (SERP) is reflected as an unfunded ABO of $24.0 million. Great Plains Energy has approximately $14.7 million of assets in a non-qualified trust for this plan as of December 31, 2017, and expects to fund future benefit payments from these assets.

The expected long-term rate of return on plan assets represents Great Plains Energy's estimate of the long-term return on plan assets and is based on historical and projected rates of return for current and planned asset classes in the plans' investment portfolios. Assumed projected rates of return for each asset class were selected after analyzing historical experience and future expectations of the returns of various asset classes. Based on the target asset allocation for each asset class, the overall expected rate of return for the portfolios was developed and adjusted for the effect of projected benefits paid from plan assets and future plan contributions. The following tables provide the weighted-average assumptions used to determine benefit obligations and net costs.

Weighted-average assumptions used to determine the benefit obligation at December 31	Pension Benefits		Other Benefits	
	2017	2016	2017	2016
Discount rate	3.72%	4.31%	3.64%	4.20%
Rate of compensation increase	3.62%	3.62%	3.50%	3.50%

Weighted-average assumptions used to determine net costs for years ended December 31	Pension Benefits		Other Benefits	
	2017	2016	2017	2016
Discount rate	4.31%	4.54%	4.20%	4.47%
Expected long-term return on plan assets	6.73%	7.14%	2.00% *	2.54% *
Rate of compensation increase	3.62%	3.62%	3.50%	3.50%

*after tax

Great Plains Energy expects to contribute $84.0 million to the pension plans in 2018 to meet Employee Retirement Income Security Act of 1974, as amended (ERISA) funding requirements and regulatory orders, the majority of which is expected to be paid by KCP&L. Great Plains Energy's funding policy is to contribute amounts sufficient to meet the ERISA funding requirements and MPSC and KCC rate orders plus additional amounts as considered appropriate; therefore, actual contributions may differ from expected contributions. Great Plains Energy also expects to contribute $4.6 million to other post-retirement benefit plans in 2018, the majority of which is expected to be paid by KCP&L.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid through 2027.

	Pension Benefits	Other Benefits
	(millions)	
2018	$ 79.3	$ 9.2
2019	82.2	9.2
2020	84.7	9.6
2021	86.0	10.1
2022	86.5	10.4
2023-2027	459.9	55.6

Pension plan assets are managed in accordance with prudent investor guidelines contained in the ERISA requirements. The investment strategy supports the objective of the fund, which is to earn the highest possible return on plan assets within a reasonable and prudent level of risk. The portfolios are invested, and periodically rebalanced, to achieve targeted allocations of approximately 33% U.S. large cap and small cap equity securities, 21% international equity securities, 36% fixed income securities, 7% real estate, 1% commodities and 2% hedge funds. Fixed income securities include domestic and foreign corporate bonds, collateralized mortgage obligations and asset-backed securities, U.S. government agency, state and local obligations, U.S. Treasury notes and money market funds.

The fair values of Great Plains Energy's pension plan assets at December 31, 2017 and 2016, by asset category are in the following tables.

		Fair Value Measurements Using			
Description	**December 31 2017**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Assets measured at NAV**
			(millions)		
Pension Plans					
Equity securities					
U.S. [(a)]	$ 279.8	$ 236.4	$ —	$ —	$ 43.4
International [(b)]	176.0	123.5	—	—	52.5
Real estate [(c)]	46.4	13.6	—	—	32.8
Commodities [(d)]	17.0	—	—	—	17.0
Fixed income securities					
Fixed income funds [(e)]	71.8	21.4	—	—	50.4
U.S. Treasury	51.5	51.5	—	—	—
U.S. Agency, state and local obligations	18.3	—	18.3	—	—
U.S. corporate bonds [(f)]	119.2	—	119.2	—	—
Foreign corporate bonds	12.5	—	12.5	—	—
Hedge funds [(g)]	15.7	—	—	—	15.7
Cash equivalents	35.6	35.6	—	—	—
Other	4.6	—	4.6	—	—
Total	$ 848.4	$ 482.0	$ 154.6	$ —	$ 211.8

Description	December 31 2016	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Assets measured at NAV
Pension Plans			(millions)		
Equity securities					
U.S. [a]	$ 247.6	$ 213.0	$ —	$ —	$ 34.6
International [b]	163.7	120.4	—	—	43.3
Real estate [c]	42.7	12.4	—	—	30.3
Commodities [d]	14.1	—	—	—	14.1
Fixed income securities					
Fixed income funds [e]	65.1	20.9	—	—	44.2
U.S. Treasury	52.2	52.2	—	—	—
U.S. Agency, state and local obligations	17.9	—	17.9	—	—
U.S. corporate bonds [f]	120.2	—	120.2	—	—
Foreign corporate bonds	9.3	—	9.3	—	—
Hedge funds [g]	15.6	—	—	—	15.6
Cash equivalents	31.7	31.7	—	—	—
Other	(3.3)	—	(3.3)	—	—
Total	$ 776.8	$ 450.6	$ 144.1	$ —	$ 182.1

[a] At December 31, 2017 and 2016, this category is comprised of $75.5 million and $128.8 million, respectively, of traded mutual funds valued at daily listed prices and $160.9 million and $84.2 million, respectively, of traded common stocks and exchange traded funds. At December 31, 2017 and 2016, this category also includes $43.4 million and $34.6 million, respectively, of institutional common/collective trust funds valued at net asset value (NAV) per share (or its equivalent) and is not categorized in the fair value hierarchy.

[b] At December 31, 2017 and 2016, this category is comprised of $95.6 million and $92.8 million, respectively, of traded mutual funds valued at daily listed prices and $27.9 million and $27.6 million, respectively, of traded American depository receipts, global depository receipts and ordinary shares. At December 31, 2017 and 2016, this category also includes $52.5 million and $43.3 million, respectively, of institutional common/collective trust funds valued at NAV per share (or its equivalent) and is not categorized in the fair value hierarchy.

[c] At December 31, 2017 and 2016, this category is comprised of $13.6 million and $12.4 million, respectively, of traded real estate investment trusts. At December 31, 2017 and 2016, this category also includes $32.8 million and $30.3 million, respectively, of institutional common/collective trust funds and a limited partnership valued at NAV per share (or its equivalent) and is not categorized in the fair value hierarchy.

[d] Consists of institutional common/collective trust funds valued at NAV per share (or its equivalent) and is not categorized in the fair value hierarchy.

[e] At December 31, 2017 and 2016, this category is comprised of $21.4 million and $20.9 million, respectively, of traded mutual funds valued at daily listed prices. At December 31, 2017 and 2016, this category also includes $50.4 million and $44.2 million, respectively, of institutional common/collective trust funds valued at NAV per share (or its equivalent) and is not categorized in the fair value hierarchy.

[f] At December 31, 2017 and 2016, this category is comprised of $113.3 million and $115.7 million, respectively, of corporate bonds. At December 31, 2017 and 2016, there were also $3.2 million and $2.3 million, respectively, of collateralized mortgage obligations and $2.7 million and $2.2 million, respectively, of other asset-backed securities.

[g] Consists of closely-held limited partnerships valued at NAV per share (or its equivalent) and is not categorized in the fair value hierarchy.

Other post-retirement plan assets are also managed in accordance with prudent investor guidelines contained in the ERISA requirements. The investment strategy supports the objective of the funds, which is to preserve capital, maintain sufficient liquidity and earn a consistent rate of return. Other post-retirement plan assets are invested primarily in fixed income securities, which may include domestic and foreign corporate bonds, collateralized mortgage obligations and asset-backed securities, U.S. government agency, state and local obligations, U.S. Treasury notes and money market funds, as well as domestic and international equity funds.

The fair values of Great Plains Energy's other post-retirement plan assets at December 31, 2017 and 2016, by asset category are in the following tables.

		Fair Value Measurements Using			
Description	**December 31 2017**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Assets measured at NAV**
Other Post-Retirement Benefit Plans			(millions)		
Equity securities	$ 3.7	$ 3.7	$ —	$ —	$ —
Fixed income securities					
Fixed income fund[(a)]	56.4	—	—	—	56.4
U.S. Treasury	3.0	3.0	—	—	—
U.S. Agency, state and local obligations	5.5	—	5.5	—	—
U.S. corporate bonds[(b)]	18.7	—	18.7	—	—
Foreign corporate bonds	1.6	—	1.6	—	—
Cash equivalents	25.3	25.3	—	—	—
Mutual funds	0.2	0.2	—	—	—
Other	1.4	—	1.4	—	—
Total	$ 115.8	$ 32.2	$ 27.2	$ —	$ 56.4

		Fair Value Measurements Using			
Description	**December 31 2016**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Assets measured at NAV**
Other Post-Retirement Benefit Plans			(millions)		
Equity securities	$ 4.1	$ 4.1	$ —	$ —	$ —
Fixed income securities					
Fixed income fund[(a)]	62.7	—	—	—	62.7
U.S. Treasury	3.9	3.9	—	—	—
U.S. Agency, state and local obligations	4.3	—	4.3	—	—
U.S. corporate bonds[(b)]	17.8	—	17.8	—	—
Foreign corporate bonds	1.6	—	1.6	—	—
Cash equivalents	19.5	19.5	—	—	—
Other	1.7	0.2	1.5	—	—
Total	$ 115.6	$ 27.7	$ 25.2	$ —	$ 62.7

[(a)] At December 31, 2017 and 2016, this category includes $56.4 million and $62.7 million, respectively, of an institutional common/collective trust fund valued at NAV per share (or its equivalent) and is not categorized in the fair value hierarchy.

[(b)] At December 31, 2017 and 2016, this category is comprised of $15.1 million and $14.0 million, respectively, of corporate bonds, $0.5 million and $0.5 million, respectively, of collateralized mortgage obligations and $3.1 million and $3.3 million, respectively, of other asset-backed securities.

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. The cost trend assumed for 2017 and 2018 was 6.5% and 6.8%, respectively, with the rate declining through 2027 to the ultimate cost trend rate of 4.5%.

The effects of a one-percentage point change in the assumed health care cost trend rates, holding all other assumptions constant, at December 31, 2017, are detailed in the following table.

	Increase		Decrease	
	(millions)			
Effect on total service and interest component	$	0.2	$	(0.2)
Effect on post-retirement benefit obligation		0.4		(0.3)

Employee Savings Plans
Great Plains Energy has defined contribution savings plans (401(k)) that cover substantially all employees. Great Plains Energy matches employee contributions, subject to limits. The annual cost of the plans was approximately $10.9 million in 2017, $11.5 million in 2016 and $10.6 million in 2015. KCP&L's annual cost of the plans was approximately $7.7 million in 2017, $8.0 million in 2016 and $7.9 million in 2015.

10. EQUITY COMPENSATION

Great Plains Energy's Long-Term Incentive Plan is an equity compensation plan approved by Great Plains Energy's shareholders. The Long-Term Incentive Plan permits the grant of restricted stock, restricted stock units, bonus shares, stock options, stock appreciation rights, director shares, director deferred share units, performance shares and other stock-based awards to directors, officers and other employees of Great Plains Energy and KCP&L. The maximum number of shares of Great Plains Energy common stock that can be issued under the plan is 8.0 million. Common stock shares delivered by Great Plains Energy under the Long-Term Incentive Plan may be authorized but unissued, held in the treasury or purchased on the open market (including private purchases) in accordance with applicable securities laws. Great Plains Energy expects to purchase common stock on the open market during 2018 to satisfy performance share payments and director deferred share unit conversion. Forfeiture rates are based on historical forfeitures and future expectations and are reevaluated annually.

The following table summarizes Great Plains Energy's and KCP&L's equity compensation expense and the associated income tax benefit.

	2017		2016		2015	
Great Plains Energy	(millions)					
Equity compensation expense	$	6.3	$	5.0	$	4.0
Income tax benefit		2.4		1.6		1.4
KCP&L						
Equity compensation expense	$	4.2	$	3.2	$	2.6
Income tax benefit		1.6		1.0		0.9

Performance Shares
The payment of performance shares is contingent upon achievement of specific performance goals over a stated period of time as approved by the Compensation and Development Committee of the Board. The number of performance shares ultimately paid can vary from the number of shares initially granted depending on Great Plains Energy's performance over stated performance periods. Compensation expense for performance shares is calculated by recognizing the portion of the fair value for each reporting period for which the requisite service has been rendered. Dividends are accrued over the vesting period and paid in cash based on the number of performance shares ultimately paid.

The fair value of performance share awards is estimated using the market value of the Company's stock at the valuation date and a Monte Carlo simulation technique that incorporates assumptions for inputs of expected volatilities, dividend yield and risk-free rates. Expected volatility is based on daily stock price change during a historical period commensurate with the remaining term of the performance period of the grant. The risk-free rate is based upon the rate at the time of the evaluation for zero-coupon government bonds with a maturity consistent with the remaining performance period of the grant. The dividend yield is based on the most recent dividends paid and the actual closing stock price on the valuation date. For shares granted in 2017, inputs for expected volatility, dividend yield and risk-free rates were 18%, 3.8% and 1.58%, respectively.

Performance share activity is summarized in the following table. Performance adjustment represents the number of shares of common stock related to performance shares ultimately issued that can vary from the number of performance shares initially granted depending on Great Plains Energy's performance over a stated period of time.

	Performance Shares	Grant Date Fair Value*
Beginning balance January 1, 2017	625,100	$ 28.13
Granted	236,433	31.26
Earned	(212,992)	28.48
Forfeited	(103,454)	29.24
Ending balance December 31, 2017	545,087	29.12

* weighted-average

At December 31, 2017, the remaining weighted-average contractual term was 1.1 years. The weighted-average grant-date fair value of shares granted was $31.26, $31.41 and $24.03 in 2017, 2016 and 2015, respectively. At December 31, 2017, there was $6.1 million of total unrecognized compensation expense, net of forfeiture rates, related to performance shares granted under the Long-Term Incentive Plan, which will be recognized over the remaining weighted-average contractual term. The total fair value of performance shares earned and paid was $6.1 million, $7.4 million and $0.5 million in 2017, 2016 and 2015, respectively.

Restricted Stock

Restricted stock cannot be sold or otherwise transferred by the recipient prior to vesting and has a value equal to the fair market value of the shares on the issue date. Restricted stock shares vest over a stated period of time with accruing reinvested dividends subject to the same restrictions. Compensation expense, calculated by multiplying shares by the grant-date fair value related to restricted stock, is recognized over the stated vesting period. Restricted stock activity is summarized in the following table.

	Nonvested Restricted Stock	Grant Date Fair Value*
Beginning balance January 1, 2017	249,672	$ 27.20
Granted and issued	81,040	28.68
Vested	(112,813)	26.92
Forfeited	(25,497)	28.10
Ending balance December 31, 2017	192,402	27.87

* weighted-average

At December 31, 2017, the remaining weighted-average contractual term was 1.2 years. The weighted-average grant-date fair value of shares granted was $28.68, $29.41 and $25.89 in 2017, 2016 and 2015, respectively. At December 31, 2017, there was $2.1 million of total unrecognized compensation expense, net of forfeiture rates, related to nonvested restricted stock granted under the Long-Term Incentive Plan, which will be recognized over the remaining weighted-average contractual term. Total fair value of shares vested was $3.0 million, $1.8 million and $2.2 million in 2017, 2016 and 2015, respectively.

Director Deferred Share Units

Non-employee directors receive shares of Great Plains Energy's common stock as part of their annual retainer. Each director may elect to defer receipt of their shares by receiving Director Deferred Share Units that convert to shares of Great Plains Energy's common stock at the end of January in the year after departure from the Board or such other time as elected by each director. Director Deferred Share Units have a value equal to the market value of Great Plains Energy's common stock on the grant date with accruing dividends. Compensation expense, calculated by multiplying the director deferred share units by the related grant-date fair value, is recognized at the grant date.

The total fair value of shares of Director Deferred Share Units issued was insignificant for 2017 and 2016. Director Deferred Share Units activity is summarized in the following table.

	Share Units	Grant Date Fair Value*
Beginning balance January 1, 2017	138,587	$ 23.96
Issued	23,435	30.09
Converted	(22,871)	21.81
Ending balance December 31, 2017	139,151	25.35

* weighted-average

11. SHORT-TERM BORROWINGS AND SHORT-TERM BANK LINES OF CREDIT

Great Plains Energy's $200 Million Revolving Credit Facility

Great Plains Energy's $200 million revolving credit facility with a group of banks expires in October 2019. The facility's terms permit transfers of unused commitments between this facility and the KCP&L and GMO facilities discussed below, with the total amount of the facility not exceeding $400 million at any one time. A default by Great Plains Energy or any of its significant subsidiaries on other indebtedness totaling more than $50.0 million is a default under the facility. Under the terms of this facility, Great Plains Energy is required to maintain a consolidated indebtedness to consolidated capitalization ratio, as defined in the facility, not greater than 0.65 to 1.00 at all times. At December 31, 2017, Great Plains Energy was in compliance with this covenant. At December 31, 2017, Great Plains Energy had $11.0 million of outstanding cash borrowings at a weighted-average interest rate of 2.94% and had issued $1.0 million in letters of credit under the credit facility. At December 31, 2016, Great Plains Energy had no outstanding cash borrowings and had issued $1.0 million in letters of credit under the credit facility.

KCP&L's $600 Million Revolving Credit Facility and Commercial Paper

KCP&L's $600 million revolving credit facility with a group of banks provides support for its issuance of commercial paper and other general corporate purposes and expires in October 2019. Great Plains Energy and KCP&L may transfer up to $200 million of unused commitments between Great Plains Energy's and KCP&L's facilities. A default by KCP&L on other indebtedness totaling more than $50.0 million is a default under the facility. Under the terms of this facility, KCP&L is required to maintain a consolidated indebtedness to consolidated capitalization ratio, as defined in the facility, not greater than 0.65 to 1.00 at all times. At December 31, 2017, KCP&L was in compliance with this covenant. At December 31, 2017, KCP&L had $167.5 million of commercial paper outstanding at a weighted-average interest rate of 1.95%, had issued letters of credit totaling $2.7 million and had no outstanding cash borrowings under the credit facility. At December 31, 2016, KCP&L had $132.9 million of commercial paper outstanding at a weighted-average interest rate of 0.98%, had issued letters of credit totaling $2.8 million and had no outstanding cash borrowings under the credit facility.

GMO's $450 Million Revolving Credit Facility and Commercial Paper

GMO's $450 million revolving credit facility with a group of banks provides support for its issuance of commercial paper and other general corporate purposes and expires in October 2019. Great Plains Energy and GMO may transfer up to $200 million of unused commitments between Great Plains Energy's and GMO's facilities. A default by GMO or any of its significant subsidiaries on other indebtedness totaling more than $50.0 million is a default under the facility. Under the terms of this facility, GMO is required to maintain a consolidated indebtedness to consolidated capitalization ratio, as defined in the facility, not greater than 0.65 to 1.00 at all times. At December 31, 2017, GMO was in compliance with this covenant. At December 31, 2017, GMO had $209.3 million of commercial paper outstanding at a weighted-average interest rate of 1.85%, had issued letters of credit totaling $2.1 million and had no outstanding cash borrowings under the credit facility. At December 31, 2016, GMO had $201.9 million of commercial paper outstanding at a weighted-average interest rate of 1.02%, had issued letters of credit totaling $1.9 million and had no outstanding cash borrowings under the credit facility.

Great Plains Energy's $864.5 Million Term Loan Facility

In connection with the Original Merger Agreement, Great Plains Energy entered into a commitment letter for a 364-day senior unsecured bridge term loan facility, originally for an aggregate principal amount of $8.017 billion to support the anticipated transaction and provide flexibility for the timing of long-term financing. Following Great Plains Energy's completed acquisition financings, the aggregate principal amount of the facility was subsequently reduced to $864.5 million and the expiration date of the facility was extended to November 30, 2017. The remaining commitment of $864.5 million was terminated in July 2017 in connection with the Amended Merger Agreement.

12. LONG-TERM DEBT

Great Plains Energy's and KCP&L's long-term debt is detailed in the following table.

	Year Due	December 31 2017	2016
KCP&L		(millions)	
General Mortgage Bonds			
2.95% EIRR bonds	2023	$ 79.5	$ 110.5
7.15% Series 2009A (8.59% rate)[a]	2019	400.0	400.0
Senior Notes			
5.85% Series (5.72% rate)[a]		—	250.0
6.375% Series (7.49% rate)[a]	2018	350.0	350.0
3.15% Series	2023	300.0	300.0
3.65% Series	2025	350.0	350.0
6.05% Series (5.78% rate)[a]	2035	250.0	250.0
5.30% Series	2041	400.0	400.0
4.20% Series	2047	300.0	—
EIRR Bonds			
1.329% Series 2007A and 2007B[b]	2035	146.5	146.5
2.875% Series 2008	2038	23.4	23.4
Current maturities		(350.0)	(281.0)
Unamortized discount and debt issuance costs		(17.2)	(15.4)
Total KCP&L excluding current maturities[c]		2,232.2	2,284.0
Other Great Plains Energy			
GMO First Mortgage Bonds 9.44% Series	2018-2021	4.6	5.7
GMO Senior Notes			
8.27% Series	2021	80.9	80.9
3.49% Series A	2025	125.0	125.0
4.06% Series B	2033	75.0	75.0
4.74% Series C	2043	150.0	150.0
GMO Medium Term Notes			
7.33% Series	2023	3.0	3.0
7.17% Series	2023	7.0	7.0
Great Plains Energy Senior Notes			
6.875% Series (7.33% rate)[a]		—	100.0
4.85% Series	2021	350.0	350.0
5.292% Series	2022	287.5	287.5
Current maturities		(1.1)	(101.1)
Unamortized discount and premium, net and debt issuance costs		(1.5)	(1.8)
Total Great Plains Energy excluding current maturities[c]		$ 3,312.6	$ 3,365.2

(a) Rate after amortizing gains/losses recognized in other comprehensive income (OCI) on settlements of interest rate hedging instruments

(b) Variable rate

(c) At December 31, 2017 and 2016, does not include $50.0 million and $21.9 million of secured Series 2005 Environmental Improvement Revenue Refunding (EIRR) bonds because the bonds were repurchased in September 2015 and are held by KCP&L

Amortization of Debt Expense

Great Plains Energy's and KCP&L's amortization of debt expense is detailed in the following table.

	2017	2016	2015
		(millions)	
KCP&L	$ 3.0	$ 3.2	$ 3.0
Other Great Plains Energy	26.9	30.6	1.1
Total Great Plains Energy	$ 29.9	$ 33.8	$ 4.1

In 2017 and 2016, Other Great Plains Energy includes $23.6 million and $29.6 million, respectively, of amortization of debt expense related to Great Plains Energy's bridge term loan facility. Fees related to this facility were amortized over the term of the facility.

KCP&L General Mortgage Bonds

KCP&L has issued mortgage bonds under the Indenture. The Indenture creates a mortgage lien on substantially all of KCP&L's utility plant. Mortgage bonds totaling $479.5 million and $510.5 million were outstanding at December 31, 2017 and 2016, respectively. KCP&L repaid its $31.0 million secured Series 1992 EIRR bonds at maturity in July 2017.

KCP&L Senior Notes

In June 2017, KCP&L issued, at a discount, $300.0 million of 4.20% unsecured Senior Notes, maturing in 2047. KCP&L also repaid its $250.0 million of 5.85% unsecured Senior Notes at maturity in June 2017.

KCP&L Municipal Bond Insurance Policies

KCP&L's secured Series 2005 EIRR bonds totaling $50.0 million and $21.9 million, respectively, are covered by a municipal bond insurance policy between KCP&L and Syncora Guarantee, Inc. (Syncora). The insurance agreements between KCP&L and Syncora provide for reimbursement by KCP&L for any amounts that Syncora pays under the municipal bond insurance policies. The insurance agreements contain a covenant that the indebtedness to total capitalization ratio of KCP&L and its consolidated subsidiaries will not be greater than 0.68 to 1.00. At December 31, 2017, KCP&L was in compliance with this covenant. KCP&L is also restricted from issuing additional bonds under its General Mortgage Indenture if, after giving effect to such additional bonds, the proportion of secured debt to total indebtedness would be more than 75%, or more than 50% if the long term rating for such bonds by S&P Global Ratings or Moody's Investors Service would be at or below A- or A3, respectively. The insurance agreement covering the unsecured Series 2005 EIRR bonds also required KCP&L to provide collateral to Syncora in the form of $50.0 million of Mortgage Bonds Series 2005 EIRR Insurer due 2035 for KCP&L's obligations under the insurance agreement as a result of KCP&L issuing general mortgage bonds in 2009 (other than refunding of outstanding general mortgage bonds) that resulted in the aggregate amount of outstanding general mortgage bonds exceeding 10% of total capitalization. The bonds are not incremental debt for KCP&L but collateralize Syncora's claim on KCP&L if Syncora was required to meet its obligation under the insurance agreement. In the event of a default under the insurance agreements, Syncora may take any available legal or equitable action against KCP&L, including seeking specific performance of the covenants.

GMO First Mortgage Bonds

GMO has issued mortgage bonds under the General Mortgage Indenture and Deed of Trust dated April 1, 1946, as supplemented. The Indenture creates a mortgage lien on a portion of GMO's utility plant. Mortgage bonds totaling $4.6 million and $5.7 million, respectively, were outstanding at December 31, 2017 and 2016.

GMO Senior Notes

Under the terms of the note purchase agreement for GMO's Series A, B and C Senior Notes, GMO is required to maintain a consolidated indebtedness to consolidated capitalization ratio, as defined in the agreement, not greater than 0.65 to 1.00 at all times. In addition, GMO's priority debt, as defined in the agreement, cannot exceed 15% of consolidated tangible net worth, as defined in the agreement. At December 31, 2017, GMO was in compliance with these covenants.

Great Plains Energy Senior Notes

In March 2017, Great Plains Energy issued $4.3 billion of senior notes in order to fund the majority of the cash portion of the acquisition of Westar under the Original Merger Agreement.

In July 2017, as a result of the Amended Merger Agreement, Great Plains Energy determined in its reasonable judgment that the acquisition of Westar would not close prior to November 30, 2017 and exercised its special optional redemption right to redeem the senior notes issued in March 2017. The redemption price was equal to 101% of the principle amount of the senior notes, including accrued and unpaid interest, for a total redemption cost of $4,400.1 million. As a result of the redemption, Great Plains Energy recorded a loss on extinguishment of debt of $82.8 million in July 2017.

Great Plains Energy repaid its $100.0 million of 6.875% unsecured Senior Notes at maturity in September 2017.

Scheduled Maturities

Great Plains Energy's and KCP&L's long-term debt maturities for the next five years are detailed in the following table.

	2018	2019	2020	2021	2022
			(millions)		
Great Plains Energy	$ 351.1	$ 401.1	$ 1.1	$ 432.0	$ 287.5
KCP&L	350.0	400.0	—	—	—

13. COMMON STOCK

Great Plains Energy has an effective shelf registration statement for the sale of unlimited amounts of securities with the SEC that became effective in March 2015 and expires in March 2018. In September 2016, Great Plains Energy filed a post-effective amendment to its shelf registration statement to register depositary shares and preference stock among the types of securities that Great Plains Energy may offer and sell. Great Plains Energy does not expect to replace this shelf registration statement prior to the closing of the anticipated merger with Westar.

In September 2016, Great Plains Energy shareholders approved an amendment to Great Plains Energy's articles of incorporation, increasing the authorized number of shares of common stock, without par value, to 600 million shares from 250 million shares.

In October 2016, Great Plains Energy completed a registered public offering of 60.5 million shares of common stock, without par value, at a public offering price of $26.45 per share, for total gross proceeds of approximately $1.6 billion (net proceeds of approximately $1.55 billion after issuance costs). Great Plains Energy planned to use proceeds from the offering to finance a portion of the cash consideration for the acquisition of Westar under the Original Merger Agreement.

Great Plains Energy has shares of common stock registered with the SEC for its Dividend Reinvestment and Direct Stock Purchase Plan. The plan allows for the purchase of common shares by reinvesting dividends or making optional cash payments. Great Plains Energy can issue new shares or purchase shares on the open market for the plan. At December 31, 2017, 0.9 million shares remained available for future issuances.

Great Plains Energy has shares of common stock registered with the SEC for a defined contribution savings plan (401(k)). Shares issued under the plan may be either newly issued shares or shares purchased in the open market. At December 31, 2017, 0.5 million shares remained available for future issuances.

Treasury shares are held for future distribution upon issuance of shares in conjunction with the Company's Long-Term Incentive Plan.

Great Plains Energy's articles of incorporation restrict the payment of common stock dividends in the event common equity is 25% or less of total capitalization. Certain conditions in the MPSC and KCC orders authorizing the holding company structure require Great Plains Energy and KCP&L to maintain consolidated common equity of at least 30% and 35%, respectively, of total capitalization (including only the amount of short-term debt in excess of the amount of construction work in progress). Under the Federal Power Act, KCP&L and GMO generally can pay dividends only out of retained earnings. The revolving credit agreements of Great Plains Energy, KCP&L and GMO and the note purchase agreement for GMO's Series A, B and C Senior Notes contain a covenant requiring the respective company to maintain a consolidated indebtedness to consolidated total capitalization ratio of not more than 0.65 to 1.00 at all times. Under the Amended Merger Agreement, Great Plains Energy is also restricted from paying a quarterly common stock dividend in excess of $0.275 per share without the consent of Westar.

As of December 31, 2017, all of Great Plains Energy's and KCP&L's retained earnings and net income were free of restrictions. As a result of the above restrictions, Great Plains Energy's subsidiaries had restricted net assets of approximately $2.8 billion as of December 31, 2017. The restrictions are not expected to affect the Companies' ability to pay dividends at the current level in the foreseeable future.

14. PREFERRED STOCK

At December 31, 2017, 1.6 million shares of Cumulative No Par Preferred Stock, 390,000 shares of Cumulative Preferred Stock, $100 par value and 11.0 million shares of no par Preference Stock were authorized under Great Plains Energy's articles of incorporation.

Series A Mandatory Convertible Preferred Stock
On May 29, 2016, Great Plains Energy entered into a stock purchase agreement with OMERS, pursuant to which Great Plains Energy would issue and sell to OMERS 750,000 shares of Series A Preferred Stock, for an aggregate purchase price equal to $750 million at the closing of the Original Merger Agreement.

In July 2017, as a result of the Amended Merger Agreement, Great Plains Energy and OMERS terminated their stock purchase agreement for the Series A Preferred Stock. As a result of this termination, Great Plains Energy recorded $15 million of previously deferred offering fees to non-operating expenses in the third quarter of 2017.

Series B Mandatory Convertible Preferred Stock
In October 2016, Great Plains Energy completed a registered public offering of 17.3 million depositary shares, each representing a 1/20th interest in a share of Great Plains Energy's Series B Preferred Stock, without par value, at a public offering price of $50 per depositary share for total gross proceeds of $862.5 million (net proceeds of approximately $836.2 million after issuance costs). Great Plains Energy planned to use proceeds from the offering to fund a portion of the cash consideration for the acquisition of Westar under the Original Merger Agreement.

Each depositary share entitled the holder of such depositary share, through the bank depositary, to a 1/20th interest in the rights and preferences of the Series B Preferred Stock, including conversion, dividend, liquidation and voting rights, subject to the terms of the deposit agreement.

Unless previously converted or redeemed, on or around September 15, 2019, each outstanding share of Series B Preferred Stock would automatically convert into a number of shares of Great Plains Energy common stock equal to a conversion rate.

Dividends on the Series B Preferred Stock were payable on a cumulative basis when, as and if declared by Great Plains Energy's Board of Directors, and subject to Missouri law, at an annual rate of 7.00% on the liquidation preference of $1,000 per share of Series B Preferred Stock (or $50 per depositary share), payable in cash, Great Plains Energy common stock or a combination thereof.

Great Plains Energy's Series B Preferred Stock also contained an acquisition termination redemption option whereby in the event that the Original Merger Agreement was terminated or if Great Plains Energy determined in its reasonable judgment that the acquisition of Westar would not close or if the acquisition of Westar had not closed by November 30, 2017, then Great Plains Energy could at its sole option (but was not required to) redeem all of the Series B Preferred Stock. If exercised, the redemption price would be equal to either:

(a) $1,000 per share plus accumulated and unpaid dividends up to the redemption date; or
(b) if the average price of Great Plains Energy's common stock exceeded a certain threshold amount, then a repurchase price that is equal to a make-whole formula.

The Series B Preferred Stock also contained a fundamental change conversion option whereby upon the occurrence of certain events deemed to be a fundamental change, including an acquisition, liquidation, or delisting of Great Plains Energy common stock, holders of the Series B Preferred Stock could:

(a) convert their existing shares into shares of Great Plains Energy common stock; and
(b) receive a dividend make-whole payment.

As a result of the Amended Merger Agreement, Great Plains Energy determined in its reasonable judgment that the acquisition of Westar under the Original Merger Agreement would not close and exercised its acquisition termination redemption option and redeemed the Series B Preferred Stock in August 2017. The Series B Preferred Stock was redeemed at a redemption price that was equal to a make-whole formula set forth in the terms of the Series B Preferred Stock. The total cost of the redemption was $963.4 million. Great Plains Energy made the entire redemption payment in cash.

The dividend make-whole provisions within both the acquisition termination redemption and fundamental change conversion options discussed above represented embedded derivatives that in accordance with GAAP, were accounted for on a combined basis separately from the Series B Preferred Stock and reported at fair value. The fair value of the Series B Preferred Stock dividend make-whole provisions at inception and December 31, 2016 was insignificant. As part of the $963.4 million redemption of the Series B Preferred Stock, the Series B Preferred Stock dividend make-whole provisions liability was settled in August 2017. In 2017, Great Plains Energy recognized a loss of $124.8 million for the settlement of these provisions, which is recorded within loss on Series B Preferred Stock dividend make-whole provisions on the consolidated statements of comprehensive income (loss).

Great Plains Energy also recognized a redemption premium of $2.4 million in connection with the redemption of the Series B Preferred Stock in 2017. This premium is represented as the difference between the redemption cost of $963.4 million and the $836.2 million carrying value of the Series B Preferred Stock, less the $124.8 million paid to settle the Series B Preferred Stock dividend make-whole provisions. The redemption premium is recorded as a reduction to earnings (loss) available for common shareholders and is recorded within preferred stock dividend requirements and redemption premium on the consolidated statements of comprehensive income (loss).

15. COMMITMENTS AND CONTINGENCIES

Environmental Matters

Great Plains Energy and KCP&L are subject to extensive federal, state and local environmental laws, regulations and permit requirements relating to air and water quality, waste management and disposal, natural resources and health and safety. In addition to imposing continuing compliance obligations and remediation costs, these laws, regulations and permits authorize the imposition of substantial penalties for noncompliance, including fines, injunctive relief and other sanctions. The cost of complying with current and future environmental requirements is expected to be material to Great Plains Energy and KCP&L. Failure to comply with environmental requirements or to timely recover environmental costs through rates could have a material effect on Great Plains Energy's and KCP&L's results of operations, financial position and cash flows.

Great Plains Energy's and KCP&L's current estimates of capital expenditures (exclusive of AFUDC and property taxes) over the next five years to comply with environmental regulations are in the following table. The total cost of compliance with any existing, proposed or future laws and regulations may be significantly different from these cost estimates provided.

	2018	2019	2020	2021	2022
			(millions)		
Great Plains Energy	$ 14.6	$ 2.8	$ 7.7	$ 20.1	$ 63.1
KCP&L	14.5	2.8	7.7	20.1	63.1

The Companies expect to seek recovery of the costs associated with environmental requirements through rate increases; however, there can be no assurance that such rate increases would be granted. The Companies may be subject to materially adverse rate treatment in response to competitive, economic, political, legislative or regulatory factors and/or public perception of the Companies' environmental reputation.

The following discussion groups environmental and certain associated matters into the broad categories of air and climate change, water, solid waste and remediation.

Clean Air Act and Climate Change Overview

The Clean Air Act Amendments of 1990 (Clean Air Act) and associated regulations enacted by the EPA form a comprehensive program to preserve and enhance air quality. States are required to establish regulations and programs to address all requirements of the Clean Air Act and have the flexibility to enact more stringent requirements. All of Great Plains Energy's and KCP&L's generating facilities, and certain of their other facilities, are subject to the Clean Air Act.

Climate Change

The Companies' current generation capacity is primarily coal-fired and is estimated to produce about one ton of carbon dioxide (CO_2) per MWh, or approximately 17 million tons and 13 million tons per year for Great Plains Energy and KCP&L, respectively. The Companies are subject to existing greenhouse gas reporting regulations and certain greenhouse gas requirements. Federal or state legislation concerning the reduction of emissions of greenhouse gases, including CO_2, could be enacted in the future. At the international level, the Paris Agreement was adopted in December 2015 by nearly 200 countries and became effective in November 2016. The Paris Agreement does not result in any new, legally binding obligations on the U.S. to meet a particular greenhouse gas emissions target, but establishes a framework for international cooperation on climate change. In June 2017, U.S. President Donald Trump announced the U.S. would withdraw from the Paris Agreement. Under the rules of the Paris Agreement, the earliest any country can withdraw is November 2020. Other international agreements legally binding on the U.S. may be reached in the future. Greenhouse gas legislation has the potential of having significant financial and operational impacts on Great Plains Energy and KCP&L; however, the ultimate financial and operational consequences to Great Plains Energy and KCP&L cannot be determined until such legislation is passed. In the absence of new Congressional mandates, the EPA is proceeding with the regulation of greenhouse gases under the existing Clean Air Act.

In August 2015, the EPA finalized CO_2 emission standards for new, modified and reconstructed affected fossil-fuel-fired electric utility generating units. The standards would not apply to Great Plains Energy's and KCP&L's existing units unless the units were modified or reconstructed in the future. Also in August 2015, the EPA finalized its Clean Power Plan which sets CO_2 emission performance rates for existing affected fossil-fuel-fired electric generating units. Nationwide, by 2030, the EPA projects the Clean Power Plan would achieve CO_2 emission reductions from the power sector of approximately 32% from CO_2 emission levels in 2005.

In February 2016, the U.S. Supreme Court granted a stay of the Clean Power Plan putting the rule on hold pending review in the U.S. Court of Appeals for the District of Columbia Circuit and any subsequent review by the U.S. Supreme Court if such review is sought. In October 2017, the EPA proposed to repeal the Clean Power Plan on the basis that it exceeded the EPA's statutory authority. In December 2017, the EPA issued an advance notice of proposed rulemaking (ANPRM) to solicit comments as the agency considers proposing a future rule to replace the Clean Power Plan. In the ANPRM, the EPA is considering proposing emission guidelines to limit greenhouse gas emissions from existing electric utility generating units. Compliance with the Clean Power Plan or any replacement rule has the potential of having significant financial and operational impacts on Great Plains Energy and KCP&L; however, the ultimate financial and operational consequences to Great Plains Energy and KCP&L cannot be determined until the outcome of the EPA's proposal to repeal the Clean Power Plan and pending litigation is known.

Clean Water Act

The Clean Water Act and associated regulations enacted by the EPA form a comprehensive program to restore and preserve water quality. Like the Clean Air Act, states are required to establish regulations and programs to address all requirements of the Clean Water Act, and have the flexibility to enact more stringent requirements. All of Great Plains Energy's and KCP&L's generating facilities, and certain of their other facilities, are subject to the Clean Water Act.

In May 2014, the EPA finalized regulations pursuant to Section 316(b) of the Clean Water Act regarding cooling water intake structures pursuant to a court approved settlement. KCP&L generation facilities with cooling water intake structures are subject to the best technology available standards based on studies completed to comply with such standards. The rule provides flexibility to work with the states to develop the best technology available to minimize aquatic species impacted by being pinned against intake screens (impingement) or drawn into cooling water systems (entrainment). Estimated costs to comply with Section 316(b) of the Clean Water Act are included in the estimated capital expenditures table above.

KCP&L holds a permit from the Missouri Department of Natural Resources (MDNR) covering water discharge from its Hawthorn Station. The permit authorizes KCP&L to, among other things, withdraw water from the Missouri River for cooling purposes and return the heated water to the Missouri River. KCP&L has applied for a renewal of this permit and the EPA has submitted an interim objection letter regarding the allowable amount of heat that can be contained in the returned water. Until this matter is resolved, KCP&L continues to operate under its current permit. Great Plains Energy and KCP&L cannot predict the outcome of this matter; however, while less significant outcomes are possible, this matter may require a reduction in generation, installation of cooling towers or other technology to cool the water, or both, any of which could have a significant impact on Great Plains Energy's and KCP&L's results of operations, financial position and cash flows.

Solid Waste

Solid and hazardous waste generation, storage, transportation, treatment and disposal are regulated at the federal and state levels under various laws and regulations. In December 2014, the EPA finalized regulations to regulate coal combustion residuals (CCRs) under the Resource Conservation and Recovery Act (RCRA) subtitle D to address the risks from the disposal of CCRs generated from the combustion of coal at electric generating facilities. The Companies use coal in generating electricity and dispose of the CCRs in both on-site facilities and facilities owned by third parties. KCP&L's Iatan, La Cygne, and Montrose Stations and GMO's Sibley Station have on-site facilities affected by the rule. The rule requires periodic assessments; groundwater monitoring; location restrictions; design and operating requirements; recordkeeping and notifications; and closure, among other requirements, for CCR units. The rule was promulgated in the Federal Register on April 17, 2015, and became effective six months after promulgation with various obligations effective at specified times within the rule. Estimated capital costs to comply with the CCR rule are included in the estimated capital expenditures table above. Certain requirements of the rule would require Great Plains Energy or KCP&L to expedite or incur additional capital expenditures in the future.

Great Plains Energy and KCP&L have AROs on their balance sheets for closure and post-closure of ponds and landfills containing CCRs. Certain requirements of the rule could in the future require further evaluation of the expected method of compliance and refinement of assumptions underlying the cost estimates for closure and post-closure. Great Plains Energy's and KCP&L's AROs could increase from the amounts presently recorded.

Remediation

Certain federal and state laws, including the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), hold current and previous owners or operators of contaminated facilities and persons who arranged for the disposal or treatment of hazardous substances liable for the cost of investigation and cleanup. CERCLA and other laws also authorize the EPA and other agencies to issue orders compelling potentially responsible parties to clean up sites that are determined to present an actual or potential threat to human health or the environment. GMO retains some environmental liability for several operations and investments it no longer owns. In addition, GMO also owns, or has acquired liabilities from companies that once owned or operated, former manufactured gas plant (MGP) sites, which are subject to the supervision of the EPA and various state environmental agencies.

At December 31, 2017 and 2016, KCP&L had $0.3 million accrued for environmental remediation expenses, which covers ground water monitoring at a former MGP site. The amount accrued was established on an undiscounted basis and KCP&L does not currently have an estimated time frame over which the accrued amount may be paid.

In addition to the $0.3 million accrual above, at December 31, 2017 and 2016, Great Plains Energy had $1.5 million and $1.4 million, respectively, accrued for the future investigation and remediation of certain additional GMO identified MGP sites and retained liabilities. This estimate was based upon review of the potential costs associated with conducting investigative and remedial actions at identified sites, as well as the likelihood of whether such actions will be necessary. This estimate could change materially after further investigation, and could also be affected by the actions of environmental agencies and the financial viability of other potentially responsible parties; however, given the uncertainty of these items the possible loss or range of loss in excess of the amount accrued is not estimable.

GMO has pursued recovery of remediation costs from insurance carriers and other potentially responsible parties. As a result of a settlement with an insurance carrier, approximately $1.6 million in insurance proceeds less an annual deductible is available to GMO to recover qualified MGP remediation expenses. GMO would seek recovery of additional remediation costs and expenses through rate increases; however, there can be no assurance that such rate increases would be granted.

Contractual Commitments

Great Plains Energy's and KCP&L's expenses related to lease commitments are detailed in the following table.

	2017	2016	2015
		(millions)	
Great Plains Energy	$ 14.2	$ 15.0	$ 16.8
KCP&L	13.1	13.7	15.0

Great Plains Energy's and KCP&L's contractual commitments at December 31, 2017, excluding pensions and long-term debt, are detailed in the following tables.

Great Plains Energy

	2018	2019	2020	2021	2022	After 2022	Total
Lease commitments				(millions)			
Operating lease	$ 12.1	$ 9.3	$ 9.7	$ 9.7	$ 9.5	$ 101.0	$ 151.3
Capital lease	0.4	0.4	0.4	0.4	0.4	2.7	4.7
Purchase commitments							
Fuel	210.4	180.1	67.3	5.1	37.4	80.7	581.0
Power	47.3	47.3	47.3	47.4	47.6	414.6	651.5
Other	20.9	14.7	6.7	5.5	2.4	35.9	86.1
Total contractual commitments	$ 291.1	$ 251.8	$ 131.4	$ 68.1	$ 97.3	$ 634.9	$ 1,474.6

KCP&L

	2018	2019	2020	2021	2022	After 2022	Total
Lease commitments				(millions)			
Operating lease	$ 11.3	$ 9.3	$ 9.7	$ 9.7	$ 9.5	$ 101.0	$ 150.5
Capital lease	0.2	0.2	0.2	0.2	0.2	1.4	2.4
Purchase commitments							
Fuel	177.5	159.8	51.8	5.1	37.4	80.7	512.3
Power	34.8	34.8	34.8	34.9	35.1	289.8	464.2
Other	20.0	12.7	5.8	4.6	1.6	31.4	76.1
Total contractual commitments	$ 243.8	$ 216.8	$ 102.3	$ 54.5	$ 83.8	$ 504.3	$ 1,205.5

Great Plains Energy's and KCP&L's lease commitments end in 2048. Operating lease commitments include rail cars to serve jointly-owned generating units where KCP&L is the managing partner. Of the amounts included in the table above, KCP&L will be reimbursed by the other owners for approximately $1.2 million in 2018 and approximately $0.4 million per year from 2019 to 2025, for a total of $4.0 million.

Fuel commitments consist of commitments for nuclear fuel, coal and coal transportation. Power commitments consist of commitments for renewable energy under power purchase agreements. Other represents individual commitments entered into in the ordinary course of business.

16. LEGAL PROCEEDINGS

GMO Western Energy Crisis

In response to complaints of excessive prices in the California energy markets, FERC issued an order in July 2001 requiring net sellers of power in the California markets from October 2, 2000, through June 20, 2001, at prices above a FERC-determined competitive market clearing price, to make refunds to net purchasers of power in the California market during that time period. MPS Merchant was a net purchaser of power during the refund period.

In November 2014, FERC issued an order finding that MPS Merchant engaged in tariff violations during the periods prior to October 2, 2000 (the Summer Period) and ordered refunds in the form of disgorgement of certain revenues. In November 2015 and February 2016, FERC issued additional orders regarding the refunds MPS Merchant owed.

In October 2016, MPS Merchant reached a settlement agreement, which was subsequently revised in February 2017, with certain California utilities and governmental agencies that would settle all issues in the case in exchange for $7.5 million of cash consideration as well as MPS Merchant's interest in additional funds it was entitled to during the refund period discussed above. In September 2017, the settlement agreement was approved by FERC and the settlement payment was made by MPS Merchant in October 2017. In accordance with the terms of the settlement agreement, the $7.5 million of cash consideration accrued interest at the FERC interest rate beginning on January 1, 2017, until the date of the payment of the settlement. At December 31, 2016, Great Plains Energy had accrued for the cash consideration pursuant to the settlement agreement.

17. GUARANTEES

In the ordinary course of business, Great Plains Energy and certain of its subsidiaries enter into various agreements providing financial or performance assurance to third parties on behalf of certain subsidiaries. Such agreements include, for example, guarantees and letters of credit. These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to a subsidiary on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiary's intended business purposes. The majority of these agreements guarantee the Company's own future performance, so a liability for the fair value of the obligation is not recorded.

At December 31, 2017, Great Plains Energy has provided $133.5 million of credit support for GMO as follows:

- Great Plains Energy direct guarantees to GMO counterparties totaling $38.0 million, which expire in 2018 and
- Great Plains Energy guarantee of GMO long-term debt totaling $95.5 million, which includes debt with maturity dates ranging from 2018 to 2023.

Great Plains Energy has also guaranteed GMO's commercial paper program. At December 31, 2017, GMO had $209.3 million commercial paper outstanding.

18. RELATED PARTY TRANSACTIONS AND RELATIONSHIPS

KCP&L employees manage GMO's business and operate its facilities at cost, including GMO's 18% ownership interest in KCP&L's Iatan Nos. 1 and 2. The operating expenses and capital costs billed from KCP&L to GMO were $196.3 million for 2017, $194.4 million for 2016 and $183.6 million for 2015.

KCP&L and GMO are also authorized to participate in the Great Plains Energy money pool, an internal financing arrangement in which funds may be lent on a short-term basis to KCP&L and GMO from Great Plains Energy and between KCP&L and GMO. At December 31, 2017 and 2016, KCP&L had no outstanding receivables or payables under the money pool.

The following table summarizes KCP&L's related party net receivables.

	December 31	
	2017	2016
	(millions)	
Net receivable from GMO	$ 65.8	$ 64.6
Net receivable from Great Plains Energy	18.9	2.6

19. FAIR VALUE MEASUREMENTS

GAAP defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. GAAP establishes a fair value hierarchy, which prioritizes the inputs to valuation techniques used to measure fair value into three broad categories, giving the highest priority to quoted prices in active markets for identical assets or liabilities and lowest priority to unobservable inputs. A definition of the various levels, as well as discussion of the various measurements within the levels, is as follows:

Level 1 – Unadjusted quoted prices for identical assets or liabilities in active markets that Great Plains Energy and KCP&L have access to at the measurement date.

Level 2 – Market-based inputs for assets or liabilities that are observable (either directly or indirectly) or inputs that are not observable but are corroborated by market data.

Level 3 – Unobservable inputs, reflecting Great Plains Energy's and KCP&L's own assumptions about the assumptions market participants would use in pricing the asset or liability.

Great Plains Energy and KCP&L record cash and cash equivalents and short-term borrowings on the balance sheet at cost, which approximates fair value due to the short-term nature of these instruments.

Interest Rate Derivatives
In June 2016, Great Plains Energy entered into four interest rate swaps, with a total notional amount of $4.4 billion, to hedge against interest rate fluctuations on future issuances of long-term debt expected to be issued to finance a portion of the cash consideration for the acquisition of Westar under the Original Merger Agreement. The interest rate swaps were designated as economic hedges (non-hedging derivatives). Settlement of the interest rate swaps was contingent on the consummation of the acquisition of Westar. In March 2017, in connection with Great Plains Energy's $4.3 billion senior note issuance, the settlement value of the interest rate swaps to Great Plains Energy of $140.6 million was fixed.

In July 2017, the interest rate swap agreements were amended to make their cash settlement contingent on the consummation of the anticipated merger with Westar under the Amended Merger Agreement by November 30, 2018. Also in July 2017, Great Plains Energy redeemed its $4.3 billion senior notes that the interest rate swaps were entered into to hedge.

The fair value of the interest rate swaps recorded on Great Plains Energy's balance sheets reflects a contingency factor that management believes is representative of what a market participant would use in valuing these instruments in order to account for the contingent nature of the cash settlement of the interest rate swaps. The contingency factor was 0.35 at December 31, 2017 and 2016. At December 31, 2017 and 2016, the fair value of the interest rate swaps was $91.4 million and $79.3 million, respectively, and was recorded on the consolidated balance sheets in interest rate derivative instruments.

Due to the redemption of Great Plains Energy’s $4.3 billion senior notes in July 2017 and the fact that the interest rate swaps no longer serve as economic hedges, Great Plains Energy recorded changes in the fair value of the interest rate swaps after July 2017 in non-operating income on Great Plains Energy’s consolidated statements of comprehensive income (loss). All changes in the fair value of the interest rate swaps prior to July 2017 were recorded in interest charges. For 2017 and 2016, Great Plains Energy recognized gains of $12.1 million and $79.3 million, respectively, for the change in fair value of the interest rate swaps. Of these amounts, $14.0 million of gains were recorded in non-operating income in 2017.

Fair Value of Long-Term Debt
Great Plains Energy and KCP&L record long-term debt on the balance sheet at amortized cost. The fair value of long-term debt is measured as a Level 2 liability and is based on quoted market prices, with the incremental borrowing rate for similar debt used to determine fair value if quoted market prices are not available. At December 31, 2017, the book value and fair value of Great Plains Energy's long-term debt, including current maturities, were $3.7 billion and $4.0 billion, respectively. At December 31, 2016, the book value and fair value of Great Plains Energy's long-term debt, including current maturities, were $3.8 billion and $4.0 billion, respectively. At December 31, 2017, the book value and fair value of KCP&L's long-term debt, including current maturities, were $2.6 billion and $2.8 billion, respectively. At December 31, 2016, the book value and fair value of KCP&L's long-term debt, including current maturities, were $2.6 billion and $2.7 billion, respectively.

Supplemental Executive Retirement Plan
At December 31, 2017 and 2016, GMO's SERP rabbi trusts included $14.7 million and $16.0 million, respectively, of fixed income funds valued at net asset value per share (or its equivalent) that are not categorized in the fair value hierarchy. The fixed income fund invests primarily in intermediate and long-term debt securities, can be redeemed immediately and is not subject to any restrictions on redemptions.

The following tables include Great Plains Energy's and KCP&L's balances of financial assets and liabilities measured at fair value on a recurring basis.

Description	December 31 2017	Level 1	Level 2	Level 3
KCP&L		(millions)		
Assets				
Nuclear decommissioning trust [a]				
Equity securities	$ 183.8	$ 183.8	$ —	$ —
Debt securities				
U.S. Treasury	35.3	35.3	—	—
U.S. Agency	0.4	—	0.4	—
State and local obligations	2.1	—	2.1	—
Corporate bonds	34.1	—	34.1	—
Foreign governments	0.1	—	0.1	—
Cash equivalents	2.5	2.5	—	—
Other	0.1	0.1	—	—
Total nuclear decommissioning trust	258.4	221.7	36.7	—
Self-insured health plan trust [b]				
Equity securities	0.5	0.5	—	—
Debt securities	2.7	0.3	2.4	—
Cash and cash equivalents	7.7	7.7	—	—
Total self-insured health plan trust	10.9	8.5	2.4	—
Total	$ 269.3	$ 230.2	$ 39.1	$ —
Other Great Plains Energy				
Assets				
Interest rate derivative instruments [c]	$ 91.4	$ —	$ —	$ 91.4
Total	$ 91.4	$ —	$ —	$ 91.4
Great Plains Energy				
Assets				
Nuclear decommissioning trust [a]	$ 258.4	$ 221.7	$ 36.7	$ —
Self-insured health plan trust [b]	10.9	8.5	2.4	—
Interest rate derivative instruments [c]	91.4	—	—	91.4
Total	$ 360.7	$ 230.2	$ 39.1	$ 91.4

Description	December 31 2016	Level 1	Level 2	Level 3
KCP&L		(millions)		
Assets				
Nuclear decommissioning trust [(a)]				
Equity securities	$ 153.9	$ 153.9	$ —	$ —
Debt securities				
U.S. Treasury	27.8	27.8	—	—
U.S. Agency	1.7	—	1.7	—
State and local obligations	3.2	—	3.2	—
Corporate bonds	32.4	—	32.4	—
Foreign governments	0.1	—	0.1	—
Cash equivalents	3.8	3.8	—	—
Total nuclear decommissioning trust	222.9	185.5	37.4	—
Self-insured health plan trust [(b)]				
Equity securities	0.9	0.9	—	—
Debt securities	4.8	0.1	4.7	—
Cash and cash equivalents	5.6	5.6	—	—
Total self-insured health plan trust	11.3	6.6	4.7	—
Total	$ 234.2	$ 192.1	$ 42.1	$ —
Other Great Plains Energy				
Assets				
Interest rate derivative instruments [(c)]	$ 79.3	$ —	$ —	$ 79.3
Total	$ 79.3	$ —	$ —	$ 79.3
Great Plains Energy				
Assets				
Nuclear decommissioning trust [(a)]	$ 222.9	$ 185.5	$ 37.4	$ —
Self-insured health plan trust [(b)]	11.3	6.6	4.7	—
Interest rate derivative instruments [(c)]	79.3	—	—	79.3
Total	$ 313.5	$ 192.1	$ 42.1	$ 79.3

(a) Fair value is based on quoted market prices of the investments held by the fund and/or valuation models.

(b) Fair value is based on quoted market prices of the investments held by the trust. Debt securities classified as Level 1 are comprised of U.S. Treasury securities. Debt securities classified as Level 2 are comprised of corporate bonds, U.S. Agency, state and local obligations, and other asset-backed securities.

(c) At December 31, 2017, the fair value of interest rate derivative instruments is based on the settlement value of $140.6 million discounted by a contingency factor of 0.35 that management believes is representative of what a market participant would use in valuing these instruments in order to account for the contingent nature of the cash settlement of these instruments. At December 31, 2016, the fair value of interest rate derivative instruments is determined by calculating the net present value of expected payments and receipts under the interest rate swaps using observable market inputs including interest rates and London Interbank Offered Rate swap rates discounted by a contingency factor of 0.35. A decrease in the contingency factor would result in a higher fair value measurement. The contingency factor will increase or decrease in response to facts and circumstances that in the view of a market participant, would increase or decrease the likelihood that the merger with Westar is not consummated. Because of the unobservable nature of the contingency factor, the interest rate derivatives have been classified as Level 3.

The following table reconciles the beginning and ending balances for all Level 3 assets measured at fair value on a recurring basis.

Great Plains Energy

Fair Value Measurements Using Significant Unobservable Inputs (Level 3)		
	Derivative Instruments	
	2017	**2016**
	(millions)	
Net asset at January 1	$ 79.3	$ —
Total realized/unrealized gains (losses):		
included in interest charges	(1.9)	79.3
included in non-operating income	14.0	—
included in loss on Series B Preferred Stock dividend make-whole provisions	(124.8)	—
Settlements	124.8	—
Net asset at December 31	$ 91.4	$ 79.3
Total unrealized gains (losses) relating to assets still on the consolidated balance sheet at December 31:		
included in interest charges	$ (1.9)	$ 79.3
included in non-operating income	$ 14.0	$ —

See Note 14 for additional information concerning the Series B Preferred Stock dividend make-whole provisions.

20. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

The following tables reflect the change in the balances of each component of accumulated other comprehensive income (loss) for Great Plains Energy and KCP&L.

Great Plains Energy

	Gains and Losses on Cash Flow Hedges[(a)]	**Defined Benefit Pension Items[(a)]**	**Total[(a)]**
		(millions)	
2017			
Beginning balance January 1	$ (4.5)	$ (2.1)	$ (6.6)
Other comprehensive loss before reclassification	—	(0.9)	(0.9)
Amounts reclassified from accumulated other comprehensive loss	4.9	0.4	5.3
Net current period other comprehensive income (loss)	4.9	(0.5)	4.4
Ending balance December 31	$ 0.4	$ (2.6)	$ (2.2)
2016			
Beginning balance January 1	$ (10.1)	$ (1.9)	$ (12.0)
Other comprehensive loss before reclassifications	—	(0.7)	(0.7)
Amounts reclassified from accumulated other comprehensive loss	5.6	0.5	6.1
Net current period other comprehensive income (loss)	5.6	(0.2)	5.4
Ending balance December 31	$ (4.5)	$ (2.1)	$ (6.6)

(a) Net of tax

KCP&L

		Gains and Losses on Cash Flow Hedges[a]
		(millions)
2017		
Beginning balance January 1	$	(4.2)
Amounts reclassified from accumulated other comprehensive loss		4.6
Net current period other comprehensive income		4.6
Ending balance December 31	$	0.4
2016		
Beginning balance January 1	$	(9.6)
Amounts reclassified from accumulated other comprehensive loss		5.4
Net current period other comprehensive income		5.4
Ending balance December 31	$	(4.2)

[a] Net of tax

The following tables reflect the effect on certain line items of net income from amounts reclassified out of each component of accumulated other comprehensive income (loss) for Great Plains Energy and KCP&L.

Great Plains Energy

Details about Accumulated Other Comprehensive Loss Components	Amount Reclassified from Accumulated Other Comprehensive Loss				Affected Line Item in the Income Statement
	2017		2016		
	(millions)				
Gains (losses) on cash flow hedges (effective portion)					
Interest rate contracts	$	(7.9)	$	(9.2)	Interest charges
		(7.9)		(9.2)	Income before income tax expense and income from equity investments
		3.0		3.6	Income tax benefit
	$	(4.9)	$	(5.6)	Net income (loss)
Amortization of defined benefit pension items					
Net losses included in net periodic benefit costs	$	(0.7)	$	(0.8)	Utility operating and maintenance expenses
		(0.7)		(0.8)	Income before income tax expense and income from equity investments
		0.3		0.3	Income tax benefit
	$	(0.4)	$	(0.5)	Net income (loss)
Total reclassifications, net of tax	$	(5.3)	$	(6.1)	Net income (loss)

KCP&L

Details about Accumulated Other Comprehensive Loss Components	**Amount Reclassified from Accumulated Other Comprehensive Income (Loss)**		**Affected Line Item in the Income Statement**
	2017	**2016**	
	(millions)		
Gains (losses) on cash flow hedges (effective portion)			
Interest rate contracts	$ (7.5)	$ (8.8)	Interest charges
	(7.5)	(8.8)	Income before income tax expense
	2.9	3.4	Income tax benefit
Total reclassifications, net of tax	$ (4.6)	$ (5.4)	Net income

21. TAXES

Components of income tax expense are detailed in the following tables.

Great Plains Energy	**2017**	**2016**	**2015**
Current income taxes		(millions)	
Federal	$ (1.7)	$ 0.3	$ (0.2)
State	1.0	0.7	(1.1)
Total	(0.7)	1.0	(1.3)
Deferred income taxes			
Federal	223.5	140.6	96.9
State	11.9	29.5	28.0
Total	235.4	170.1	124.9
Investment tax credit			
Deferral	—	2.5	0.5
Amortization	(1.4)	(1.4)	(1.4)
Total	(1.4)	1.1	(0.9)
Income tax expense	$ 233.3	$ 172.2	$ 122.7

Great Plains Energy's 2017 federal deferred income tax expense includes $130.3 million of additional income tax expense due to the impacts of U.S. federal income tax reform, discussed further below.

KCP&L	**2017**	**2016**	**2015**
Current income taxes		(millions)	
Federal	$ 37.4	$ 24.8	$ (18.7)
State	8.3	4.7	(3.4)
Total	45.7	29.5	(22.1)
Deferred income taxes			
Federal	74.7	76.4	81.9
State	8.8	17.0	17.5
Total	83.5	93.4	99.4
Investment tax credit			
Deferral	—	—	0.5
Amortization	(1.0)	(1.0)	(1.0)
Total	(1.0)	(1.0)	(0.5)
Income tax expense	$ 128.2	$ 121.9	$ 76.8

Effective Income Tax Rates

Effective income tax rates reflected in the financial statements and the reasons for their differences from the statutory federal rates are detailed in the following tables.

Great Plains Energy	2017	2016	2015
Federal statutory income tax rate	35.0%	35.0%	35.0%
Differences between book and tax depreciation not normalized	0.1	(0.1)	—
Amortization of investment tax credits	(1.1)	(0.3)	(0.4)
Federal income tax credits	(5.8)	(2.6)	(4.1)
State income taxes	8.3	4.2	4.0
Transaction-related costs	42.5	0.9	—
Valuation allowance	8.9	—	1.5
Federal tax rate change	95.3	—	—
Other	0.3	0.2	0.5
Effective income tax rate	183.5%	37.3%	36.5%

The increase in Great Plains Energy's effective income tax rate for 2017 is driven by significant transaction-related costs incurred in connection with the anticipated merger with Westar that are not deductible for tax purposes and the impacts of U.S. federal income tax reform, discussed further below.

KCP&L	2017	2016	2015
Federal statutory income tax rate	35.0%	35.0%	35.0%
Differences between book and tax depreciation not normalized	(0.1)	(0.3)	—
Amortization of investment tax credits	(0.3)	(0.3)	(0.5)
Federal income tax credits	(2.4)	(3.1)	(5.6)
State income taxes	3.8	4.1	4.0
Valuation allowance	0.4	—	0.3
Federal tax rate change	5.3	—	—
Other	(0.1)	(0.2)	0.3
Effective income tax rate	41.6%	35.2%	33.5%

Deferred Income Taxes

The tax effects of major temporary differences resulting in deferred income tax assets (liabilities) in the consolidated balance sheets are in the following tables.

	Great Plains Energy		KCP&L	
December 31	**2017**	**2016**	**2017**	**2016**
Noncurrent deferred income taxes	(millions)			
Plant related	$(1,549.0)	$(2,107.6)	$(1,114.9)	$(1,492.2)
Income taxes on future regulatory refunds (recoveries)	236.0	(148.7)	179.1	(123.9)
Derivative instruments	(19.2)	(17.0)	1.6	8.5
Pension and post-retirement benefits	9.4	10.5	28.6	38.6
SO_2 emission allowance sales	14.9	24.1	15.0	24.1
Fuel recovery mechanisms	(17.9)	(22.3)	(15.9)	(27.2)
Tax credit carryforwards	279.8	271.1	185.8	177.4
Customer demand programs	(17.4)	(34.3)	(11.7)	(21.8)
Solar rebates	(15.2)	(27.3)	(5.8)	(11.4)
Net operating loss carryforward	473.0	718.0	131.2	198.3
Other	6.9	20.2	(9.1)	1.3
Net noncurrent deferred income tax liability before valuation allowance	(598.7)	(1,313.3)	(616.1)	(1,228.3)
Valuation allowance	(23.0)	(16.4)	—	—
Net noncurrent deferred income tax liability	$ (621.7)	$(1,329.7)	$ (616.1)	$(1,228.3)

	Great Plains Energy		KCP&L	
December 31	**2017**	**2016**	**2017**	**2016**
	(millions)			
Gross deferred income tax assets	$ 2,017.4	$ 1,360.9	$ 1,261.5	$ 747.7
Gross deferred income tax liabilities	(2,639.1)	(2,690.6)	(1,877.6)	(1,976.0)
Net deferred income tax liability	$ (621.7)	$(1,329.7)	$ (616.1)	$(1,228.3)

Tax Credit Carryforwards

At December 31, 2017 and 2016, Great Plains Energy had $191.0 million and $183.5 million, respectively, of federal general business income tax credit carryforwards. At December 31, 2017 and 2016, KCP&L had $184.6 million and $177.4 million, respectively, of federal general business income tax credit carryforwards. The carryforwards for both Great Plains Energy and KCP&L relate primarily to Advanced Coal Investment Tax Credits and Wind Production tax credits and expire in the years 2028 to 2037. Approximately $0.5 million of Great Plains Energy's credits are related to Low Income Housing credits that were acquired in the GMO acquisition. Due to federal limitations on the utilization of income tax attributes acquired in the GMO acquisition, management expects a portion of these credits to expire unutilized and has provided a valuation allowance against $0.4 million of the federal income tax benefit.

At December 31, 2017 and 2016, Great Plains Energy had $87.6 million of federal alternative minimum tax credit carryforwards, all of which were acquired in the GMO acquisition. These credits do not expire and can be used to reduce taxes paid in the future or become refundable starting in 2018. Due to potential federal budget sequestration reductions for refundable income tax credits, management expects a portion of these credits will not be refunded and has provided a valuation allowance against $5.8 million of the federal income tax benefit.

At December 31, 2017, Great Plains Energy and KCP&L had $1.2 million of state income tax credit carryforwards. The state income tax credits relate primarily to the Company's Kansas research and development tax credits, which do not expire.

Net Operating Loss Carryforwards
At December 31, 2017 and 2016, Great Plains Energy had $382.0 million and $643.8 million, respectively, of tax benefits related to federal net operating loss (NOL) carryforwards. Approximately $179.3 million and $306.2 million at December 31, 2017 and 2016, respectively, are tax benefits related to NOLs that were acquired in the GMO acquisition. The federal NOL carryforwards expire in years 2023 to 2036. The year of origin of Great Plains Energy's related tax benefit amounts for federal NOL carryforwards as of December 31, 2017 are detailed in the following table.

Year of Origin	Amount of Benefit
	(millions)
2003	$ 9.5
2004	91.4
2005	44.4
2006	32.0
2007	0.8
2008	1.4
2009	21.9
2010	2.5
2011	65.3
2012	0.2
2013	0.8
2014	52.0
2015	59.2
2016	0.6
	$ 382.0

In addition, Great Plains Energy also had deferred tax benefits of $91.0 million and $74.2 million related to state NOLs as of December 31, 2017 and 2016, respectively. Of these amounts, approximately $42.1 million and $36.1 million at December 31, 2017 and 2016, respectively, were acquired in the GMO acquisition. Management does not expect to utilize $16.8 million of NOLs before the expiration date of the carryforwards of NOLs in certain states. Therefore, a valuation allowance has been provided against $16.8 million of state tax benefits.

Valuation Allowances
Great Plains Energy is required to assess the ultimate realization of deferred tax assets using a “more likely than not” assessment threshold. This assessment takes into consideration tax planning strategies within Great Plains Energy's control. As a result of this assessment, Great Plains Energy has established a partial valuation allowance for state tax NOL carryforwards and tax credit carryforwards. During 2017, $6.6 million of tax expense was recorded in continuing operations primarily related to a reduction in the refundable portion of federal Alternative Minimum Tax (AMT) credits.

Tax Reform
In December 2017, the U.S. Congress passed and President Donald Trump signed Public Law No. 115-97, commonly referred to as the Tax Cuts and Jobs Act (Tax Act). The Tax Act represents the first major reform in U.S. income tax law since 1986. Most notably, the Tax Act reduces the current top corporate income tax rate from 35% to 21% beginning in 2018, repeals the corporate AMT, makes existing AMT tax credit carryforwards refundable, and changes the deductibility and taxability of certain items, among other things.

In December 2017, the SEC staff issued Staff Accounting Bulletin (SAB) 118, which provides guidance on accounting for the tax effects of the Tax Act. SAB 118 provides a measurement period that should not extend beyond one year from the Tax Act enactment date for companies to complete the accounting under ASC 740, *Income Taxes*. In accordance with SAB 118, a company must reflect the income tax effects of those aspects of the Tax Act for which the accounting under ASC 740 is complete. To the extent that a company's accounting for certain income tax effects of the Tax Act is incomplete but it is able to determine a reasonable estimate, it must record a provisional estimate to be included in the financial statements. If a company cannot determine a provisional estimate to be included in the financial statements, it should continue to apply ASC 740 on the basis of the provisions of the tax laws that were in effect immediately before the enactment of the Tax Act. Great Plains Energy's and KCP&L's accounting for the Tax Act under ASC 740 as of December 31, 2017 is complete and is detailed further below.

As a result of the change in the corporate income tax rate, Great Plains Energy and KCP&L revalued and restated their deferred income tax assets and liabilities in December 2017. Great Plains Energy decreased its net deferred income tax liabilities by $814.5 million, primarily consisting of a $645.5 million adjustment for the revaluation and restatement of deferred income tax assets and liabilities included in rate base and a $222.8 million tax gross-up adjustment for ratemaking purposes. KCP&L decreased its net deferred income tax liabilities by $682.8 million, primarily consisting of a $471.8 million adjustment for the revaluation and restatement of deferred income tax assets and liabilities included in rate base and a $163.6 million tax gross-up adjustment for ratemaking purposes. The decreases to Great Plains Energy's and KCP&L's net deferred income tax liabilities included in rate base were offset by a corresponding increase in regulatory liabilities. The net regulatory liabilities will be refunded to customers in future rates by amortizing the amounts related to plant assets over the remaining useful life of the assets, and amortizing the amounts related to other items over a period to be determined in a future rate case.

Great Plains Energy recognized $130.3 million of income tax expense consisting of $110.1 million primarily related to the revaluation of GMO's non-regulated deferred income tax assets, $9.1 million related to the reassessment of the valuation allowance needed for the realization of refundable AMT credits and state NOLs and $11.1 million related to KCP&L and GMO deferred income taxes not included in rate base. KCP&L recognized $16.5 million of income tax expense related to deferred income taxes not included in rate base.

KCP&L and GMO currently recover the cost of income taxes in rates from their customers based on the 35% federal corporate income tax rate. Both KCP&L and GMO have announced their intentions to pass the income tax savings generated by the tax rate change, currently estimated at approximately $100 million annually, through to customers as part of upcoming general rate cases, including applications filed by KCP&L and GMO in Missouri in January 2018. However, both the MPSC and KCC have also initiated investigatory dockets regarding the impact of the Tax Act on customer rates and the actual rate treatment of tax reform will not be known until orders specifying that treatment are received from the MPSC and KCC. In January 2018, KCC issued an order requiring certain regulated public utilities, including KCP&L, to begin recording a regulatory liability for the difference between the new corporate tax rate and amounts currently collected in rates. The treatment of the regulatory liability will be addressed by KCC in future orders.

22. SEGMENTS AND RELATED INFORMATION

Great Plains Energy has one reportable segment based on its method of internal reporting, which segregates reportable segments based on products and services, management responsibility and regulation. The one reportable business segment is Electric Utility, consisting of KCP&L, GMO's regulated utility operations and GMO Receivables Company. Other includes GMO activity other than its regulated utility operations, GPETHC and unallocated corporate charges, including certain costs to achieve the anticipated merger with Westar. The summary of significant accounting policies applies to the reportable segment. Segment performance is evaluated based on net income (loss).

The following tables reflect summarized financial information concerning Great Plains Energy's reportable segment.

2017	Electric Utility	Other	Eliminations	Great Plains Energy
		(millions)		
Operating revenues	$ 2,708.2	$ —	$ —	$ 2,708.2
Depreciation and amortization	(371.1)	—	—	(371.1)
Interest charges	(196.9)	(125.9)	32.1	(290.7)
Income tax expense	(169.4)	(63.9)	—	(233.3)
Net income (loss)	256.9	(363.1)	—	(106.2)

2016	Electric Utility	Other	Eliminations	Great Plains Energy
		(millions)		
Operating revenues	$ 2,676.0	$ —	$ —	$ 2,676.0
Depreciation and amortization	(344.8)	—	—	(344.8)
Interest charges	(196.1)	2.5	32.1	(161.5)
Income tax expense	(164.3)	(7.9)	—	(172.2)
Net income (loss)	292.1	(2.1)	—	290.0

2015	Electric Utility	Other	Eliminations	Great Plains Energy
		(millions)		
Operating revenues	$ 2,502.2	$ —	$ —	$ 2,502.2
Depreciation and amortization	(330.4)	—	—	(330.4)
Interest charges	(190.9)	(40.5)	32.1	(199.3)
Income tax expense	(120.8)	(1.9)	—	(122.7)
Net income (loss)	223.8	(10.8)	—	213.0

	Electric Utility	Other	Eliminations	Great Plains Energy
2017		(millions)		
Assets	$11,508.1	$ 1,285.7	$ (335.9)	$12,457.9
Capital expenditures	573.5	—	—	573.5
2016				
Assets	$11,444.2	$ 2,461.3	$ (335.5)	$13,570.0
Capital expenditures	609.4	—	—	609.4
2015				
Assets	$11,045.5	$ (51.1)	$ (255.8)	$10,738.6
Capital expenditures	677.1	—	—	677.1

23. JOINTLY-OWNED ELECTRIC UTILITY PLANTS

Great Plains Energy's and KCP&L's share of jointly-owned electric utility plants at December 31, 2017, are detailed in the following tables.

Great Plains Energy

	Wolf Creek Unit	La Cygne Units	Iatan No. 1 Unit	Iatan No. 2 Unit	Iatan Common	Jeffrey Energy Center
	(millions, except MW amounts)					
Great Plains Energy's share	47%	50%	88%	73%	79%	8%
Utility plant in service	$ 1,854.2	$ 1,191.1	$ 699.9	$ 1,355.8	$ 491.1	$ 201.1
Accumulated depreciation	918.1	347.8	280.8	413.0	130.7	82.0
Nuclear fuel, net	72.4	—	—	—	—	—
Construction work in progress	91.8	8.6	31.8	35.0	21.7	2.5
2018 accredited capacity-MWs	552	699	616	641	NA	173

KCP&L

	Wolf Creek Unit	La Cygne Units	Iatan No. 1 Unit	Iatan No. 2 Unit	Iatan Common
	(millions, except MW amounts)				
KCP&L's share	47%	50%	70%	55%	61%
Utility plant in service	$ 1,854.2	$ 1,191.1	$ 561.7	$ 1,041.6	$ 401.8
Accumulated depreciation	918.1	347.8	228.9	366.6	117.5
Nuclear fuel, net	72.4	—	—	—	—
Construction work in progress	91.8	8.6	7.6	14.8	12.0
2018 accredited capacity-MWs	552	699	490	482	NA

Each owner must fund its own portion of the plant's operating expenses and capital expenditures. KCP&L's and GMO's share of direct expenses are included in the appropriate operating expense classifications in Great Plains Energy's and KCP&L's financial statements.

24. QUARTERLY OPERATING RESULTS (UNAUDITED)

Great Plains Energy	Quarter 1st	2nd	3rd	4th
2017	(millions, except per share amounts)			
Operating revenue	$ 570.7	$ 682.6	$ 857.2	$ 597.7
Operating income	47.4	176.5	305.9	73.8
Net income (loss)	(9.6)	(7.0)	10.5	(100.1)
Basic and diluted earnings (loss) per common share	(0.11)	(0.10)	0.02	(0.46)
2016				
Operating revenue	$ 572.1	$ 670.8	$ 856.8	$ 576.3
Operating income	89.9	182.3	281.9	64.8
Net income	26.4	32.0	133.6	98.0
Basic and diluted earnings per common share	0.17	0.20	0.86	0.39

KCP&L	Quarter 1st	2nd	3rd	4th
2017	(millions)			
Operating revenue	$ 395.9	$ 482.7	$ 595.7	$ 416.4
Operating income	58.2	113.8	209.9	61.8
Net income	14.2	49.6	114.1	1.9
2016				
Operating revenue	$ 400.9	$ 475.6	$ 597.6	$ 401.3
Operating income	70.6	137.9	219.2	54.4
Net income	24.6	65.9	117.7	16.8

In the fourth quarter of 2017, Great Plains Energy recorded $130.3 million of additional income tax expense due to the impacts of U.S. federal income tax reform. See Note 21 for additional information regarding the impact of tax reform on Great Plains Energy.

Quarterly data is subject to seasonal fluctuations with peak periods occurring in the summer months.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

GREAT PLAINS ENERGY

Disclosure Controls and Procedures

Great Plains Energy carried out an evaluation of its disclosure controls and procedures (as defined in Rules 13a-15(e) or 15d-15(e) under the Securities Exchange Act of 1934, as amended (the Exchange Act)). This evaluation was conducted under the supervision, and with the participation, of Great Plains Energy's management, including the chief executive officer and chief financial officer, and Great Plains Energy's disclosure committee. Based upon this evaluation, the chief executive officer and chief financial officer of Great Plains Energy have concluded as of the end of the period covered by this report that the disclosure controls and procedures of Great Plains Energy were effective at a reasonable assurance level.

Changes in Internal Control Over Financial Reporting

There has been no change in Great Plains Energy's internal control over financial reporting (as defined in Rule 13a-15(f) and 15d-15(f) of the Exchange Act) that occurred during the quarterly period ended December 31, 2017, that has materially affected, or is reasonably likely to materially affect, its internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of the effectiveness of internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) for Great Plains Energy. Under the supervision and with the participation of Great Plains Energy's chief executive officer and chief financial officer, management evaluated the effectiveness of Great Plains Energy's internal control over financial reporting as of December 31, 2017. Management used for this evaluation the framework in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations (COSO) of the Treadway Commission.

Management has concluded that, as of December 31, 2017, Great Plains Energy's internal control over financial reporting is effective based on the criteria set forth in the COSO framework. Deloitte & Touche LLP, the independent registered public accounting firm that audited the financial statements included in this annual report on Form 10-K, has issued its attestation report on Great Plains Energy's internal control over financial reporting, which is included below.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of Great Plains Energy Incorporated

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Great Plains Energy Incorporated 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 and financial statement schedules 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 and financial statement schedules.

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

KCP&L

Disclosure Controls and Procedures
KCP&L carried out an evaluation of its disclosure controls and procedures (as defined in Rules 13a-15(e) or 15d-15(e) under the Exchange Act). This evaluation was conducted under the supervision, and with the participation, of KCP&L's management, including the chief executive officer and chief financial officer, and KCP&L's disclosure committee. Based upon this evaluation, the chief executive officer and chief financial officer of KCP&L have concluded as of the end of the period covered by this report that the disclosure controls and procedures of KCP&L were effective at a reasonable assurance level.

Changes in Internal Control Over Financial Reporting
There has been no change in KCP&L's internal control over financial reporting (as defined in Rule 13a-15(f) and 15d-15(f) of the Exchange Act) that occurred during the quarterly period ended December 31, 2017, that has materially affected, or is reasonably likely to materially affect, its internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting
Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of the effectiveness of internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) for KCP&L. Under the supervision and with the participation of KCP&L's chief executive officer and chief financial officer, management evaluated the effectiveness of KCP&L's internal control over financial reporting as of December 31, 2017. Management used for this evaluation the framework in *Internal Control - Integrated Framework (2013)* issued by the COSO of the Treadway Commission.

Management has concluded that, as of December 31, 2017, KCP&L's internal control over financial reporting is effective based on the criteria set forth in the COSO framework. Deloitte & Touche LLP, the independent registered public accounting firm that audited the financial statements included in this annual report on Form 10-K, has issued its attestation report on KCP&L's internal control over financial reporting, which is included below.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholder and the Board of Directors of Kansas City Power & Light Company

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Kansas City Power & Light Company 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 and financial statement schedule as of an 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 and financial statement schedule.

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

ITEM 9B. OTHER INFORMATION

None.

PART III

Information required by Items 10-14 of Part III of this Form 10-K with respect to Great Plains Energy will be incorporated by reference to Great Plains Energy's definitive proxy statement with respect to its 2018 Annual Meeting of Shareholders (Proxy Statement), if such definitive proxy statement is filed with the SEC on or before April 30, 2018. Due to the pending merger with Westar, Great Plains Energy may not be required to file the Proxy Statement, in which case Great Plains Energy 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, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Great Plains Energy Directors
The information required by this item is incorporated by reference from the Proxy Statement, which will be filed with the SEC no later than April 30, 2018:

- Information regarding the directors of Great Plains Energy required by this item is contained in the Proxy Statement section titled "Directors."
- Information regarding compliance with Section 16(a) of the Securities Exchange Act of 1934 required by this item is contained in the Proxy Statement section titled "Security Ownership of Certain Beneficial Owners, Directors and Officers - Section 16(a) Beneficial Ownership Reporting Compliance."
- Information regarding the Audit Committee of Great Plains Energy required by this item is contained in the Proxy Statement section titled "Corporate Governance - Committees of the Board."

Great Plains Energy and KCP&L Executive Officers
Information required by this item regarding the executive officers of Great Plains Energy and KCP&L is contained in this report in the Part I, Item 1 section titled "Executive Officers."

Great Plains Energy and KCP&L Code of Ethical Business Conduct
The Companies have adopted a Code of Ethical Business Conduct (Code), which applies to all directors, officers and employees of Great Plains Energy, KCP&L and their subsidiaries. The Code is posted on the corporate governance page of the Internet websites at www.greatplainsenergy.com and www.kcpl.com. A copy of the Code is available, without charge, upon written request to Corporate Secretary, Great Plains Energy Incorporated, 1200 Main St., Kansas City, Missouri 64105. Great Plains Energy and KCP&L intend to satisfy the disclosure requirements under Item 5.05 of Form 8-K regarding an amendment to, or a waiver from, a provision of the Code that applies to the principal executive officer, principal financial officer, principal accounting officer or controller of those companies by posting such information on the corporate governance page of the Internet websites.

Other KCP&L Information
The other information required by this item regarding KCP&L has been omitted in reliance on General Instruction (I).

ITEM 11. EXECUTIVE COMPENSATION

Great Plains Energy
The information required by this item contained in the sections titled "Executive Compensation," "Director Compensation," "Compensation Discussion and Analysis", "Compensation Committee Report" and "Director Independence - Compensation Committee Interlocks and Insider Participation" of the Proxy Statement is incorporated by reference.

KCP&L
The other information required by this item regarding KCP&L has been omitted in reliance on General Instruction (I).

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Great Plains Energy
The information required by this item regarding security ownership of the directors and executive officers of Great Plains Energy contained in the section titled "Security Ownership of Certain Beneficial Owners, Directors and Officers" of the Proxy Statement is incorporated by reference.

KCP&L
The information required by this item regarding KCP&L has been omitted in reliance on General Instruction (I).

Equity Compensation Plans
Great Plains Energy's Long-Term Incentive Plan is an equity compensation plan approved by its shareholders. The Long-Term Incentive Plan permits the grant of restricted stock, restricted stock units, bonus shares, stock options, stock appreciation rights, director shares, director deferred share units, performance shares and other stock-based awards to directors, officers and other employees of Great Plains Energy and KCP&L.

KCP&L does not have an equity compensation plan; however, KCP&L officers and certain employees participate in Great Plains Energy's Long-Term Incentive Plan.

The following table provides information, as of December 31, 2017, regarding the number of common shares to be issued upon exercise of outstanding options, warrants and rights, their weighted average exercise price, and the number of shares of common stock remaining available for future issuance. The table excludes shares issued or issuable under Great Plains Energy's defined contribution savings plans.

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders			
Great Plains Energy Long-Term Incentive Plan	684,238 [1]	$ — [2]	4,022,044
Equity compensation plans not approved by security holders	—	—	—
Total	684,238 [1]	$ — [2]	4,022,044

[1] Includes 545,087 performance shares at target performance levels and director deferred share units for 139,151 shares of Great Plains Energy common stock outstanding at December 31, 2017.
[2] The performance shares and director deferred share units have no exercise price and therefore are not reflected in the weighted average exercise price.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Great Plains Energy
The information required by this item contained in the sections titled "Director Independence" and "Related Party Transactions" of the Proxy Statement is incorporated by reference.

KCP&L
The information required by this item regarding KCP&L has been omitted in reliance on General Instruction (I).

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Great Plains Energy
The information required by this item regarding the independent auditors of Great Plains Energy and its subsidiaries contained in the section titled "Ratification of Appointment of Independent Auditors" of the Proxy Statement is incorporated by reference.

KCP&L
The Audit Committee of the Great Plains Energy Board functions as the Audit Committee of KCP&L. The following table sets forth the aggregate fees billed by Deloitte & Touche LLP for audit services rendered in connection with the consolidated financial statements and reports for 2017 and 2016 and for other services rendered during 2017 and 2016 on behalf of KCP&L, as well as all out-of-pocket costs incurred in connection with these services:

Fee Category	2017	2016
Audit Fees	$ 1,304,550	$ 1,184,550
Audit-Related Fees	22,000	21,000
Tax Fees	24,905	24,822
All Other Fees	—	—
Total Fees	$ 1,351,455	$ 1,230,372

Audit Fees: Consists of fees billed for professional services rendered for the audits of the annual consolidated financial statements of KCP&L and reviews of the interim condensed consolidated financial statements included in quarterly reports. Audit fees also include: services provided by Deloitte & Touche LLP in connection with statutory and regulatory filings or engagements; audit reports on audits of the effectiveness of internal control over financial reporting and other attest services, except those not required by statute or regulation; services related to filings with the SEC, including comfort letters, consents and assistance with and review of documents filed with the SEC; and accounting research in support of the audit.

Audit-Related Fees: Consists of fees billed for assurance and related services that are reasonably related to the performance of the audit or review of consolidated financial statements of KCP&L and are not reported under "Audit Fees". These services include consultation concerning financial accounting and reporting standards.

Tax Fees: Consists of fees billed for tax compliance and related support of tax returns and other tax services, including assistance with tax audits, and tax research and planning.

All Other Fees: Consists of fees for all other services other than those described above.

Audit Committee Pre-Approval of Audit and Permissible Non-Audit Services
The Audit Committee has adopted policies and procedures for the pre-approval of all audit services, audit-related services, tax services and other services to be provided by the independent registered public accounting firm for KCP&L. The Audit Committee's policy is to pre-approve all audit, audit-related, tax or other services to be provided by the independent registered public accounting firm. Under these policies and procedures, the Audit Committee may pre-approve certain types of services, up to the aggregate fee levels it sets. Any proposed service within a pre-approved type of service that would cause the applicable fee level to be exceeded cannot be provided unless the Audit Committee either amends the applicable fee level or specifically approves the proposed service. The Audit Committee, as well, may specifically approve audit, audit-related, tax or other services on a case-by-case basis. Pre-approval is generally provided for up to one year, unless the Audit Committee specifically provides for a different period. The Company provides quarterly updates to the Audit Committee regarding actual fees spent with respect to pre-approved services. The Chairman of the Audit Committee may pre-approve audit, audit-related, tax

and other services provided by the independent registered public accounting firm as required between meetings and report such pre-approval at the next Audit Committee meeting.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

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Exhibits

Exhibit Number		Description of Document	Registrant
2.1	*	Agreement and Plan of Merger, dated as of May 29, 2016, by and among Westar Energy, Inc., Great Plains Energy Incorporated and, from and after its accession thereto, Merger Sub (as defined therein) (Exhibit 2.1 to Form 8-K filed on May 31, 2016).	Great Plains Energy
2.2	*	Amended and Restated Merger Agreement, dated as of July 9, 2017, by and among Great Plains Energy Incorporated, Westar Energy, Inc., Monarch Energy Holding, Inc., King Energy, Inc. and, solely for the purposes set forth therein, GP Star, Inc. (Exhibit 2.1 to Form 8-K filed on July 10, 2017).	Great Plains Energy
3.1	*	Articles of Incorporation of Great Plains Energy Incorporated, as amended effective September 26, 2016 (Exhibit 3.1 to Form 10-Q for the quarter ended September 30, 2016).	Great Plains Energy
3.2	*	Amended and Restated By-laws of Great Plains Energy Incorporated, as amended December 10, 2013 (Exhibit 3.1 to Form 8-K filed on December 16, 2013).	Great Plains Energy
3.3	*	Amended and Restated Articles of Consolidation of Kansas City Power & Light Company, restated as of May 6, 2014 (Exhibit 3.2 to Form 10-Q for the quarter ended March 31, 2014).	KCP&L
3.4	*	Amended and Restated By-laws of Kansas City Power & Light Company, as amended December 10, 2013 (Exhibit 3.3 to Form 8-K filed on December 16, 2013).	KCP&L
4.1	*	Indenture, dated as of June 1, 2004, between Great Plains Energy Incorporated and BNY Midwest Trust Company, as trustee (Exhibit 4.4 to Form 8-A/A filed on June 14, 2004).	Great Plains Energy
4.2	*	First Supplemental Indenture, dated as of June 14, 2004, between Great Plains Energy Incorporated and BNY Midwest Trust Company, as trustee (Exhibit 4.5 to Form 8-A/A filed on June 14, 2004).	Great Plains Energy
4.3	*	Second Supplemental Indenture, dated as of September 25, 2007, between Great Plains Energy Incorporated and The Bank of New York Trust Company, N.A., as trustee (Exhibit 4.1 to Form 8-K filed on September 26, 2007).	Great Plains Energy
4.4	*	Third Supplemental Indenture, dated as of August 13, 2010, between Great Plains Energy Incorporated and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.1 to Form 8-K filed on August 13, 2010).	Great Plains Energy
4.5	*	Fourth Supplemental Indenture, dated as of May 19, 2011, between Great Plains Energy Incorporated and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.1 to Form 8-K filed on May 19, 2011).	Great Plains Energy
4.6	*	Fifth Supplemental Indenture, dated as of March 9, 2017, between Great Plains Energy and The Bank of New York Trust Company, N.A. as trustee (Exhibit 4.1 to Form 8-K filed on March 9, 2017).	Great Plains Energy

4.7	*	Subordinated Indenture, dated as of May 18, 2009, between Great Plains Energy Incorporated and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.1 to Form 8-K filed on May 19, 2009).	Great Plains Energy
4.8	*	Supplemental Indenture No. 1, dated as of May 18, 2009, between Great Plains Energy Incorporated and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.2 to Form 8-K filed on May 19, 2009).	Great Plains Energy
4.9	*	Supplemental Indenture No. 2, dated as of March 22, 2012, between Great Plains Energy Incorporated and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.1 to Form 8-K filed on March 23, 2012).	Great Plains Energy
4.10	*	Indenture, dated as of August 24, 2001, between Aquila, Inc. and BankOne Trust Company, N.A., as trustee (Exhibit 4(d) to Registration Statement on Form S-3 (File No. 333-68400) filed by Aquila, Inc. on August 27, 2001).	Great Plains Energy
4.11	*	Second Supplemental Indenture, dated as of July 3, 2002, between Aquila, Inc. and BankOne Trust Company, N.A., as trustee (Exhibit 4(c) to Form S-4 (File No. 333-100204) filed by Aquila, Inc. on September 30, 2002).	Great Plains Energy
4.12		General Mortgage and Deed of Trust, dated as of December 1, 1986, between Kansas City Power & Light Company and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee.	Great Plains Energy KCP&L
4.13		Fifth Supplemental Indenture, dated as of September 15, 1992, between Kansas City Power & Light Company and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee.	Great Plains Energy KCP&L
4.14		Seventh Supplemental Indenture, dated as of October 1, 1993, between Kansas City Power & Light Company and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee.	Great Plains Energy KCP&L
4.15		Eighth Supplemental Indenture, dated as of December 1, 1993, between Kansas City Power & Light Company and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee.	Great Plains Energy KCP&L
4.16	*	Eleventh Supplemental Indenture, dated as of August 15, 2005, between Kansas City Power & Light Company and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee (Exhibit 4.2 to Form 10-Q for the quarter ended September 30, 2005).	Great Plains Energy KCP&L
4.17	*	Twelfth Supplemental Indenture, dated as of March 1, 2009, between Kansas City Power & Light Company and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee (Exhibit 4.2 to Form 8-K filed on March 24, 2009).	Great Plains Energy KCP&L

4.18	*	Thirteenth Supplemental Indenture, dated as of March 1, 2009, between Kansas City Power & Light Company and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee (Exhibit 4.3 to Form 8-K filed on March 24, 2009).	Great Plains Energy KCP&L
4.19	*	Fourteenth Supplemental Indenture, dated as of March 1, 2009, between Kansas City Power & Light Company and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee (Exhibit 4.4 to Form 8-K filed on March 24, 2009).	Great Plains Energy KCP&L
4.20	*	Fifteenth Supplemental Indenture, dated as of June 30, 2011, between Kansas City Power & Light Company and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee (Exhibit 4.1 to Form 10-Q for the quarter ended June 30, 2011).	Great Plains Energy KCP&L
4.21	*	Indenture, dated as of December 1, 2000, between Kansas City Power & Light Company and The Bank of New York, as trustee (Exhibit 4(a) to Form 8-K filed on December 18, 2000).	Great Plains Energy KCP&L
4.22	*	Indenture, dated as of March 1, 2002, between Kansas City Power & Light Company and The Bank of New York, as trustee (Exhibit 4.1.b. to Form 10-Q for the quarter ended March 31, 2002).	Great Plains Energy KCP&L
4.23	*	Supplemental Indenture No. 1, dated as of November 15, 2005, between Kansas City Power & Light Company and The Bank of New York, as trustee (Exhibit 4.2.j to Form 10-K for the year ended December 31, 2005).	Great Plains Energy KCP&L
4.24	*	Indenture, dated as of May 1, 2007, between Kansas City Power & Light Company and The Bank of New York Trust Company, N.A., as trustee (Exhibit 4.1 to Form 8-K filed on June 4, 2007).	Great Plains Energy KCP&L
4.25	*	Supplemental Indenture No. 1, dated as of June 4, 2007, between Kansas City Power & Light Company and The Bank of New York Trust Company, N.A., as trustee (Exhibit 4.2 to Form 8-K filed on June 4, 2007).	Great Plains Energy KCP&L
4.26	*	Supplemental Indenture No. 2, dated as of March 11, 2008, between Kansas City Power & Light Company and The Bank of New York Trust Company, N.A., as trustee (Exhibit 4.2 to Form 8-K filed on March 11, 2008).	Great Plains Energy KCP&L
4.27	*	Supplemental Indenture No. 3, dated as of September 20, 2011, between Kansas City Power & Light Company and The Bank of New York Mellon Trust Company, N.A., Trustee (Exhibit 4.1 to Form 8-K filed on September 20, 2011).	Great Plains Energy KCP&L
4.28	*	Supplemental Indenture No. 4, dated as of March 14, 2013, between Kansas City Power & Light Company and The Bank of New York Mellon Trust Company, N.A., Trustee (Exhibit 4.1 to Form 8-K filed on March 14, 2013).	Great Plains Energy KCP&L
4.29	*	Supplemental Indenture No. 5, dated as of August 18, 2015, between Kansas City Power & Light Company and The Bank of New York Mellon Trust Company, N.A., Trustee (Exhibit 4.1 to Form 8-K filed on August 18, 2015).	Great Plains Energy KCP&L

4.30	*	Supplemental Indenture No. 6 dated as of June 15, 2017 between KCP&L and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.1 to Form 8-K filed on June 15, 2017).	Great Plains Energy KCP&L
4.31	*	Note Purchase Agreement, dated August 16, 2013, among KCP&L Greater Missouri Operations Company and the purchasers party thereto (Exhibit 4.1 to Form 8-K filed on August 19, 2013).	Great Plains Energy
10.1	*+	Great Plains Energy Incorporated Amended Long-Term Incentive Plan, effective on May 7, 2002 (Exhibit 10.1.a to Form 10-K for the year ended December 31, 2002).	Great Plains Energy KCP&L
10.2	*+	Great Plains Energy Incorporated Amended Long-Term Incentive Plan, as amended effective on May 1, 2007 (Exhibit 10.1 to Form 8-K filed on May 4, 2007).	Great Plains Energy KCP&L
10.3	*+	Great Plains Energy Incorporated Amended Long-Term Incentive Plan, as amended effective on May 3, 2011 (Exhibit 10.1 to Form 8-K filed on May 6, 2011).	Great Plains Energy KCP&L
10.4	*+	Great Plains Energy Incorporated Amended Long-Term Incentive Plan, as amended effective on January 1, 2014 (Exhibit 10.1 to Form 10-Q for the quarter ended June 30, 2013).	Great Plains Energy KCP&L
10.5	*+	Great Plains Energy Incorporated Amended Long-Term Incentive Plan, as amended effective on May 3, 2016 (Exhibit 10.4 to Form 10-Q for the quarter ended June 30, 2016).	Great Plains Energy KCP&L
10.6	*+	Great Plains Energy Incorporated Long-Term Incentive Plan Awards Standards and Performance Criteria Effective as of January 1, 2013 (Exhibit 10.3 to Form 10-Q for the quarter ended March 31, 2013).	Great Plains Energy KCP&L
10.7	*+	Great Plains Energy Incorporated Long-Term Incentive Plan Awards Standards and Performance Criteria Effective as of January 1, 2014 (Exhibit 10.3 to Form 10-Q for the quarter ended March 31, 2014).	Great Plains Energy KCP&L
10.8	*+	Great Plains Energy Incorporated Long-Term Incentive Plan Awards Standards and Performance Criteria Effective as of January 1, 2015 (Exhibit 10.3 to Form 10-Q for the quarter ended March 31, 2015).	Great Plains Energy KCP&L
10.9	*+	Great Plains Energy Incorporated Long-Term Incentive Plan Awards Standards and Performance Criteria Effective as of January 1, 2016 (Exhibit 10.3 to Form 10-Q for the quarter ended March 31, 2016).	Great Plains Energy KCP&L
10.10	*+	Great Plains Energy Incorporated Long-Term Incentive Plan Awards Standards and Performance Criteria Effective as of January 1, 2017 (Exhibit 10.3 to Form 10-Q for the quarter ended March 31, 2017).	Great Plains Energy KCP&L
10.11	*+	Letter Agreement dated March 7, 2017, by and between Michael L. Deggendorf, Great Plains Energy Incorporated, Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company (Exhibit 10.5 to Form 10-Q for the quarter ended March 31, 2017).	Great Plains Energy KCP&L

10.12	*+	Retirement Agreement dated May 1, 2017, by and between Scott H. Heidtbrink, Great Plains Energy Incorporated, Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company (Exhibit 10.6 to Form 10-Q for the quarter ended March 31, 2017).	Great Plains Energy KCP&L
10.13	*+	Form of 2013 three-year Performance Share Agreement (Exhibit 10.1 to Form 10-Q for the quarter ended March 31, 2013).	Great Plains Energy KCP&L
10.14	*+	Form of 2013 Restricted Stock Agreement (Exhibit 10.2 to Form 10-Q for the quarter ended March 31, 2013).	Great Plains Energy KCP&L
10.15	*+	Form of 2014 three-year Performance Share Agreement (Exhibit 10.1 to Form 10-Q for the quarter ended March 31, 2014).	Great Plains Energy KCP&L
10.16	*+	Form of 2014 Restricted Stock Agreement (Exhibit 10.2 to Form 10-Q for the quarter ended March 31, 2014).	Great Plains Energy KCP&L
10.17	*+	Form of 2015 three-year Performance Share Agreement (Exhibit 10.1 to Form 10-Q for the quarter ended March 31, 2015).	Great Plains Energy KCP&L
10.18	*+	Form of 2015 Restricted Stock Agreement (Exhibit 10.2 to Form 10-Q for the quarter ended March 31, 2015).	Great Plains Energy KCP&L
10.19	*+	Form of 2016 three-year Performance Share Agreement (Exhibit 10.1 to Form 10-Q for the quarter ended March 31, 2016).	Great Plains Energy KCP&L
10.20	*+	Form of 2016 Restricted Stock Agreement (Exhibit 10.2 to Form 10-Q for the quarter ended March 31, 2016).	Great Plains Energy KCP&L
10.21	*+	Form of 2017 three-year Performance Share Agreement (Exhibit 10.1 to Form 10-Q for the quarter ended March 31, 2017).	Great Plains Energy KCP&L
10.22	*+	Form of 2017 Restricted Stock Agreement (Exhibit 10.2 to Form 10-Q for the quarter ended March 31, 2017).	Great Plains Energy KCP&L
10.23	*+	Aquila, Inc. 2002 Omnibus Incentive Compensation Plan (Exhibit 10.3 to Form 10-Q for the quarter ended September 30, 2002, filed by Aquila, Inc.).	Great Plains Energy KCP&L
10.24	*+	Great Plains Energy Incorporated, Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company Annual Incentive Plan amended effective as of January 1, 2016 (Exhibit 10.4 to Form 10-Q for the quarter ended March 31, 2016).	Great Plains Energy KCP&L
10.25	*+	Form of Indemnification Agreement with each officer and director (Exhibit 10-f to Form 10-K for year ended December 31, 1995).	Great Plains Energy KCP&L
10.26	*+	Form of Conforming Amendment to Indemnification Agreement with each officer and director (Exhibit 10.1.a to Form 10-Q for the quarter ended March 31, 2003).	Great Plains Energy KCP&L
10.27	*+	Form of Indemnification Agreement with each director and officer (Exhibit 10.1 to Form 8-K filed on December 8, 2008).	Great Plains Energy KCP&L

10.28	*+	Form of Indemnification Agreement with officers and directors (Exhibit 10.1.p to Form 10-K for the year ended December 31, 2005).	Great Plains Energy KCP&L
10.29	*+	Form of Indemnification Agreement with officers and directors (Exhibit 10.1 to Form 8-K filed on December 16, 2013).	Great Plains Energy KCP&L
10.30	*+	Form of Change in Control Severance Agreement with other executive officers of Great Plains Energy Incorporated and Kansas City Power & Light Company (Exhibit 10.1.e to Form 10-Q for the quarter ended September 30, 2006).	Great Plains Energy KCP&L
10.31	*+	Great Plains Energy Incorporated Supplemental Executive Retirement Plan (As Amended and Restated for I.R.C. §409A) (Exhibit 10.1.10 to Form 10-Q for the quarter ended September 30, 2007).	Great Plains Energy KCP&L
10.32	*+	Great Plains Energy Incorporated Supplemental Executive Retirement Plan (As Amended and Restated for I.R.C. §409A), as amended February 10, 2009 (Exhibit 10.1.29 to Form 10-K for the year ended December 31, 2008.	Great Plains Energy KCP&L
10.33	*+	Great Plains Energy Incorporated Supplemental Executive Retirement Plan (As Amended and Restated for I.R.C. §409A), as amended December 8, 2009 (Exhibit 10.1.27 to Form 10-K for the year ended December 31, 2009).	Great Plains Energy KCP&L
10.34	*+	Amendment dated October 28, 2014, to the Great Plains Energy Incorporated Supplemental Executive Retirement Plan as amended and restated on December 8, 2009 (Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 2014).	Great Plains Energy KCP&L
10.35	*+	Great Plains Energy Incorporated Nonqualified Deferred Compensation Plan (As Amended and Restated for I.R.C. §409A) (Exhibit 10.1.11 to Form 10-Q for the quarter ended September 30, 2007).	Great Plains Energy KCP&L
10.36	*+	Great Plains Energy Incorporated Nonqualified Deferred Compensation Plan (As Amended and Restated for I.R.C. §409A), amended effective January 1, 2010 (Exhibit 10.1.5 to Form 10-Q for the quarter ended March 31, 2010).	Great Plains Energy KCP&L
10.37	*	Joint Motion and Settlement Agreement, dated as of February 26, 2008, among Great Plains Energy Incorporated, Kansas City Power & Light Company, the Kansas Corporation Commission Staff, the Citizens' Utility Ratepayers Board, Aquila, Inc. d/b/a Aquila Networks, Black Hills Corporation, and Black Hills/ Kansas Gas Utility Company, LLC (Exhibit 10.1.7 to Form 10-Q for the quarter ended March 31, 2008).	Great Plains Energy KCP&L
10.38	*	Credit Agreement, dated as of August 9, 2010, among Great Plains Energy Incorporated, Certain Lenders, Bank of America, N.A., as Administrative Agent, and Union Bank, N.A. and Wells Fargo Bank, National Association, as Syndication Agents, Barclays Bank PLC and U.S. Bank National Association, as Documentation Agents, Banc of America Securities LLC, Union Bank, N.A. and Wells Fargo Securities, LLC as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 2010).	Great Plains Energy

10.39	*	First Amendment to Credit Agreement, dated as of December 9, 2011, among Great Plains Energy Incorporated, Certain Lenders, Union Bank, N.A. and Wells Fargo Bank, National Association, as Syndication Agents, Bank of America, N.A., as Administrative Agent, Barclays Bank PLC and U.S. Bank National Association, as Documentation Agents, Merrill Lynch, Pierce, Fenner & Smith Incorporated, Union Bank, N.A. and Wells Fargo Securities, LLC as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.59 to Form 10-K for the year ended December 31, 2011).	Great Plains Energy
10.40	*	Second Amendment to Credit Agreement, dated as of October 17, 2013, among Great Plains Energy Incorporated, Certain Lenders, Bank of America, N.A., JPMorgan Chase Bank, N.A. and Union Bank, N.A., as Syndication Agents and Wells Fargo Bank, National Association, as Administrative Agent, and Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, J.P. Morgan Securities LLC, and Union Bank, N.A., as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 2013).	Great Plains Energy
10.41	*	First Extension Agreement and Waiver, dated as of December 17, 2014, among Great Plains Energy Incorporated, Certain Lenders, Bank of America, N.A., JPMorgan Chase Bank, N.A., and MUFG Union Bank, N.A., as Syndication Agents and Wells Fargo Bank, National Association, as Administrative Agent, Swing Line Lender and an Issuer, Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, J.P. Morgan Securities LLC, and MUFG Union Bank, N.A., as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.37 to Form 10-K for the year ended December 31, 2014).	Great Plains Energy
10.42	*	Third Amendment to the Credit Agreement, dated as of June 13, 2016, among Great Plains Energy Incorporated, Certain Lenders, Bank of America, N.A., JPMorgan Chase Bank, N.A., and Union Bank, N.A., as Syndication Agents and Wells Fargo Bank, National Association, as Administrative Agent, and Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, J.P. Morgan Securities LLC, and Union Bank, N.A., as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.1 to Form 10-Q for the quarter ended June 30, 2016).	Great Plains Energy
10.43	*	Credit Agreement, dated as of August 9, 2010, among Kansas City Power & Light Company, Certain Lenders, Bank of America, N.A., as Administrative Agent, and Union Bank, N.A. and Wells Fargo Bank, National Association, as Syndication Agents, JPMorgan Chase Bank, N.A. and The Bank of Nova Scotia, as Documentation Agents, Banc of America Securities LLC, Union Bank, N.A. and Wells Fargo Securities, LLC as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.2 to Form 10-Q for the quarter ended September 30, 2010).	Great Plains Energy KCP&L

10.44	*	First Amendment to Credit Agreement, dated as of December 9, 2011, among Kansas City Power & Light Company, Certain Lenders, Union Bank, N.A. and Wells Fargo Bank, National Association, as Syndication Agents, Bank of America, N.A., as Administrative Agent, JPMorgan Chase Bank, N.A. and The Bank of Nova Scotia, as Documentation Agents, Merrill Lynch, Pierce, Fenner & Smith Incorporated, Union Bank, N.A. and Wells Fargo Securities, LLC as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.61 to Form 10-K for the year ended December 31, 2011).	Great Plains Energy KCP&L
10.45	*	Second Amendment to Credit Agreement, dated as of October 17, 2013, among Kansas City Power & Light Company, Certain Lenders, Bank of America, N.A., JPMorgan Chase Bank, N.A., and Union Bank, N.A., as Syndication Agents and Wells Fargo Bank, National Association, as Administrative Agent, and Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, J.P. Morgan Securities LLC, and Union Bank, N.A., as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.2 to Form 10-Q for the quarter ended September 30, 2013).	Great Plains Energy KCP&L
10.46	*	First Extension Agreement and Waiver, dated as of December 17, 2014, among Kansas City Power & Light Company, Certain Lenders, Bank of America, N.A., JPMorgan Chase Bank, N.A., and MUFG Union Bank, N.A., as Syndication Agents and Wells Fargo Bank, National Association, as Administrative Agent, Swing Line Lender and an Issuer, Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, J.P. Morgan Securities LLC, and MUFG Union Bank, N.A., as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.41 to Form 10-K for the year ended December 31, 2014).	Great Plains Energy KCP&L
10.47	*	Credit Agreement, dated as of August 9, 2010, among KCP&L Greater Missouri Operations Company, Great Plains Energy Incorporated, as Guarantor, Certain Lenders, Bank of America, N.A., as Administrative Agent, and Union Bank, N.A. and Wells Fargo Bank, National Association, as Syndication Agents, The Royal Bank of Scotland PLC and BNP Paribas , as Documentation Agents, Banc of America Securities LLC, Union Bank, N.A. and Wells Fargo Securities, LLC as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.3 to Form 10-Q for the quarter ended September 30, 2010).	Great Plains Energy
10.48	*	First Amendment to Credit Agreement, dated as of December 9, 2011, among KCP&L Greater Missouri Operations Company, Great Plains Energy Incorporated, as Guarantor, Certain Lenders, Union Bank, N.A. and Wells Fargo Bank, National Association, as Syndication Agents, Bank of America, N.A., as Administrative Agent, The Royal Bank of Scotland PLC and BNP Paribas, as Documentation Agents, Merrill Lynch, Pierce, Fenner & Smith Incorporated, Union Bank, N.A. and Wells Fargo Securities, LLC as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.63 to Form 10-K for the year ended December 31, 2011).	Great Plains Energy

10.49	*	Second Amendment to Credit Agreement, dated as of October 17, 2013, among KCP&L Greater Missouri Operations Company, Certain Lenders, Bank of America, N.A., JPMorgan Chase Bank, N.A., and Union Bank, N.A., as Syndication Agents and Wells Fargo Bank, National Association, as Administrative Agent, and Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, J.P. Morgan Securities LLC, and Union Bank, N.A., as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.3 to Form 10-Q for the quarter ended September 30, 2013).	Great Plains Energy
10.50	*	First Extension Agreement and Waiver, dated as of December 17, 2014, among KCP&L Greater Missouri Operations Company, Certain Lenders, Bank of America, N.A., JPMorgan Chase Bank, N.A., and MUFG Union Bank, N.A., as Syndication Agents and Wells Fargo Bank, National Association, as Administrative Agent, Swing Line Lender and an Issuer, Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, J.P. Morgan Securities LLC, and MUFG Union Bank, N.A., as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.45 to Form 10-K for the year ended December 31, 2014).	Great Plains Energy
10.51	*	Guaranty, dated as of July 15, 2008, issued by Great Plains Energy Incorporated in favor of Union Bank of California, N.A., as successor trustee, and the holders of the Aquila, Inc., 8.27% Senior Notes due November 15, 2021 (Exhibit 10.6 to Form 8-K filed on July 18, 2008).	Great Plains Energy
10.52	*	Insurance Agreement, dated as of September 1, 2005, between Kansas City Power & Light Company and XL Capital Assurance Inc. (Exhibit 10.2.e to Form 10-K for the year ended December 31, 2005).	Great Plains Energy KCP&L
10.53	*	Insurance Agreement, dated as of September 1, 2005, between Kansas City Power & Light Company and XL Capital Assurance Inc. (Exhibit 10.2.f to Form 10-K for the year ended December 31, 2005).	Great Plains Energy KCP&L
10.54	*	Purchase and Sale Agreement, dated as of July 1, 2005, between Kansas City Power & Light Company, as Originator, and Kansas City Power & Light Receivables Company, as Buyer (Exhibit 10.2.b to Form 10-Q for the quarter ended June 30, 2005).	Great Plains Energy KCP&L
10.55	*	Receivables Sale Agreement, dated as of July 1, 2005, among Kansas City Power & Light Receivables Company, as the Seller, Kansas City Power & Light Company, as the Initial Collection Agent, The Bank of Tokyo-Mitsubishi, Ltd., New York Branch, as the Agent, and Victory Receivables Corporation (Exhibit 10.2.c to Form 10-Q for the quarter ended June 30, 2005).	Great Plains Energy KCP&L
10.56	*	Amendment No. 1, dated as of April 2, 2007, among Kansas City Power & Light Receivables Company, Kansas City Power & Light Company, The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch and Victory Receivables Corporation to the Receivables Sale Agreement dated as of July 1, 2005 (Exhibit 10.2.2 to Form 10-Q for the quarter ended March 31, 2007).	Great Plains Energy KCP&L

10.57	*	Amendment No. 2, dated as of July 11, 2008, among Kansas City Power & Light Receivables Company, Kansas City Power & Light Company, The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch and Victory Receivables Corporation to the Receivables Sale Agreement dated as of July 1, 2005 (Exhibit 10.2.1 to Form 10-Q for the quarter ended June 30, 2008).	Great Plains Energy KCP&L
10.58	*	Amendment, dated as of July 9, 2009, to Receivables Sale Agreement dated as of July 1, 2005 among Kansas City Power & Light Receivables Company, Kansas City Power & Light Company, The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch and Victory Receivables Corporation (Exhibit 10.4 to Form 8-K filed on July 13, 2009).	Great Plains Energy KCP&L
10.59	*	Amendment and Waiver, dated as of September 25, 2009, to the Receivables Sale Agreement dated as of July 1, 2005 among Kansas City Power & Light Receivables Company, Kansas City Power & Light Company, The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch and Victory Receivables Corporation (Exhibit 10.2.2 to Form 10-Q for the quarter ended September 30, 2009).	Great Plains Energy KCP&L
10.60	*	Amendment, dated as of May 5, 2010, to Receivables Sale Agreement dated as of July 1, 2005 among Kansas City Power & Light Receivables Company, Kansas City Power & Light Company, The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch and Victory Receivables Corporation (Exhibit 10.2.2 to Form 10-Q for the quarter ended March 31, 2010).	Great Plains Energy KCP&L
10.61	*	Amendment, dated as of February 23, 2011, to Receivables Sale Agreement dated as of July 1, 2005 among Kansas City Power & Light Receivables Company, Kansas City Power & Light Company, The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch and Victory Receivables Corporation. (Exhibit 10.5 to Form 10-Q for the quarter ended March 31, 2011).	Great Plains Energy KCP&L
10.62	*	Amendment, dated as of September 9, 2011, to Receivables Sale Agreement dated as of July 1, 2005, among Kansas City Power & Light Receivables Company, Kansas City Power & Light Company, The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch and Victory Receivables Corporation (Exhibit 10.1 to Form 8-K filed on September 13, 2011).	Great Plains Energy KCP&L
10.63	*	Amendment dated as of September 9, 2014, to the Receivables Sales Agreement dated as of July 1, 2005, among Kansas City Power & Light Receivables Company, as the Seller, Kansas City Power & Light Company, as the Initial Collection Agent, The Bank of Tokyo-Mitsubishi, Ltd., New York Branch, as the Agent and Victory Receivables Corporation, as the Purchaser (Exhibit 10.1 to Form 8-K filed on September 15, 2014).	Great Plains Energy KCP&L
10.64	*	Amendment dated as of September 9, 2015, to the Receivables Sales Agreement dated as of July 1, 2005, among Kansas City Power & Light Receivables Company, as the Seller, Kansas City Power & Light Company, as the Initial Collection Agent, The Bank of Tokyo-Mitsubishi, Ltd., New York Branch, as the Agent and Victory Receivables Corporation, as the Purchaser (Exhibit 10.1 to Form 8-K filed on September 11, 2015).	Great Plains Energy KCP&L

10.65	*	Amendment dated as of September 9, 2016, to the Receivables Sales Agreement dated as of July 1, 2005, among Kansas City Power & Light Receivables Company, as the Seller, Kansas City Power & Light Company, as the Initial Collection Agent, The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch, as the Agent and Victory Receivables Corporation, as the Purchaser (Exhibit 10.1 to Form 8-K filed on September 13, 2016).	Great Plains Energy KCP&L
10.66	*	Purchase and Sale Agreement, dated as of May 31, 2012, between KCP&L Greater Missouri Operations Company, as Originator, and GMO Receivables Company, as Buyer (Exhibit 10.2. to Form 10-Q for the quarter ended June 30, 2012).	Great Plains Energy
10.67	*	Receivables Sale Agreement, dated as of May 31, 2012, among GMO Receivables Company, as the Seller, KCP&L Greater Missouri Operations Company, as the Initial Collection Agent, The Bank of Tokyo-Mitsubishi, Ltd., New York Branch, as the Agent, and Victory Receivables Corporation (Exhibit 10.3 to Form 10-Q for the quarter ended June 30, 2012).	Great Plains Energy
10.68	*	First Amendment dated as of September 9, 2014, to the Receivables Sales Agreement dated as of May 31, 2012, among GMO Receivables Company, as the Seller, KCP&L Greater Missouri Operations Company, as the Initial Collection Agent, The Bank of Tokyo-Mitsubishi, Ltd., New York Branch, as the Agent and Victory Receivables Corporation, as the Purchaser. (Exhibit 10.2 to Form 8-K filed on September 15, 2014).	Great Plains Energy
10.69	*	Second Amendment dated as of September 9, 2015, to the Receivables Sales Agreement dated as of May 31, 2012, among GMO Receivables Company, as the Seller, KCP&L Greater Missouri Operations Company, as the Initial Collection Agent, The Bank of Tokyo-Mitsubishi, Ltd., New York Branch, as the Agent and Victory Receivables Corporation, as the Purchaser. (Exhibit 10.2 to Form 8-K filed on September 11, 2015).	Great Plains Energy
10.70	*	Third Amendment dated as of September 9, 2016, to the Receivables Sales Agreement dated as of May 31, 2012, among GMO Receivables Company, as the Seller, KCP&L Greater Missouri Operations Company, as the Initial Collection Agent, The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch, as the Agent and Victory Receivables Corporation, as the Purchaser (Exhibit 10.2 to Form 8-K filed September 13, 2016).	Great Plains Energy
10.71	*	Amendment dated as of September 8, 2017, to the Receivables Sales Agreement dated as of July 1, 2005, among Kansas City Power & Light Receivables Company, as the Seller, Kansas City Power & Light Company, as the Initial Collection Agent, The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch, as the Agent and Victory Receivables Corporation, as the Purchaser. (Exhibit 10.1 to Form 8-K filed on September 11, 2017).	KCP&L
10.72	*	Fourth Amendment dated as of September 8, 2017, to the Receivables Sales Agreement dated as of May 31, 2012, among GMO Receivables Company, as the Seller, KCP&L Greater Missouri Operations Company, as the Initial Collection Agent, The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch, as the Agent and Victory Receivables Corporation, as the Purchaser. (Exhibit 10.2 to Form 8-K filed on September 11, 2017).	Great Plains Energy

10.73	*	Iatan Unit 2 and Common Facilities Ownership Agreement, dated as of May 19, 2006, among Kansas City Power & Light Company, Aquila, Inc., The Empire District Electric Company, Kansas Electric Power Cooperative, Inc., and Missouri Joint Municipal Electric Utility Commission (Exhibit 10.2.a to Form 10-Q for the quarter ended June 30, 2006).	Great Plains Energy KCP&L
10.74	*	Joint Motion and Settlement Agreement dated as of February 26, 2008, among Great Plains Energy Incorporated, Kansas City Power & Light Company, the Kansas Corporation Commission Staff, the Citizens' Utility Ratepayers Board, Aquila, Inc. d/b/a Aquila Networks, Black Hills Corporation, and Black Hills/ Kansas Gas Utility Company, LLC (Exhibit 10.1.7 to Form 10-Q for the quarter ended March 31, 2008).	Great Plains Energy KCP&L
10.75	*	Stipulation and Agreement dated April 24, 2009, among Kansas City Power & Light Company, Staff of the Missouri Public Service Commission, Office of Public Counsel, Praxair, Inc., Midwest Energy Users Association, U.S. Department of Energy and the U.S. Nuclear Security Administration, Ford Motor Company, Missouri Industrial Energy Consumers and Missouri Department of Natural Resources (Exhibit 10.1 to Form 8-K filed April 30, 2009).	Great Plains Energy KCP&L
10.76	*	Non-Unanimous Stipulation and Agreement dated May 22, 2009 among KCP&L Greater Missouri Operations Company, the Staff of the Missouri Public Service Commission, the Office of the Public Counsel, Missouri Department of Natural Resources and Dogwood Energy, LLC (Exhibit 10.1 to Form 8-K filed on May 27, 2009).	Great Plains Energy
10.77	*	Collaboration Agreement dated as of March 19, 2007, among Kansas City Power & Light Company, Sierra Club and Concerned Citizens of Platte County, Inc. (Exhibit 10.1 to Form 8-K filed on March 20, 2007).	Great Plains Energy KCP&L
10.78	*	Amendment to the Collaboration Agreement effective as of September 5, 2008 among Kansas City Power & Light Company, Sierra Club and Concerned Citizens of Platte County, Inc. (Exhibit 10.2.20 to Form 10-K for the year ended December 31, 2009).	Great Plains Energy KCP&L
10.79	*	Joint Operating Agreement between Kansas City Power & Light Company and Aquila, Inc., dated as of October 10, 2008 (Exhibit 10.2.2 to Form 10-Q for the quarter ended September 30, 2008).	Great Plains Energy KCP&L
12.1		Computation of Ratios of Earnings to Fixed Charges and Earnings to Combined Fixed Charges and Preferred Dividend Requirements.	Great Plains Energy
12.2		Computation of Ratio of Earnings to Fixed Charges.	KCP&L
21.1		List of Subsidiaries of Great Plains Energy Incorporated.	Great Plains Energy
23.1		Consent of Independent Registered Public Accounting Firm.	Great Plains Energy
23.2		Consent of Independent Registered Public Accounting Firm.	KCP&L

24.1		Powers of Attorney.	Great Plains Energy
24.2		Powers of Attorney.	KCP&L
31.1		Rule 13a-14(a)/15d-14(a) Certification of Terry Bassham.	Great Plains Energy
31.2		Rule 13a-14(a)/15d-14(a) Certification of Kevin E. Bryant.	Great Plains Energy
31.3		Rule 13a-14(a)/15d-14(a) Certification of Terry Bassham.	KCP&L
31.4		Rule 13a-14(a)/15d-14(a) Certification of Kevin E. Bryant.	KCP&L
32.1	**	Section 1350 Certifications.	Great Plains Energy
32.2	**	Section 1350 Certifications.	KCP&L
101.INS		XBRL Instance Document.	Great Plains Energy KCP&L
101.SCH		XBRL Taxonomy Extension Schema Document.	Great Plains Energy KCP&L
101.CAL		XBRL Taxonomy Extension Calculation Linkbase Document.	Great Plains Energy KCP&L
101.DEF		XBRL Taxonomy Extension Definition Linkbase Document.	Great Plains Energy KCP&L
101.LAB		XBRL Taxonomy Extension Labels Linkbase Document.	Great Plains Energy KCP&L
101.PRE		XBRL Taxonomy Extension Presentation Linkbase Document.	Great Plains Energy KCP&L

* Filed with the SEC as exhibits to prior SEC filings and are incorporated herein by reference and made a part hereof. The SEC filings and the exhibit number of the documents so filed, and incorporated herein by reference, are stated in parenthesis in the description of such exhibit.

** Furnished and shall not be deemed filed for the purpose of Section 18 of the Securities Exchange Act of 1934, as amended (the Exchange Act). Such document shall not be incorporated by reference into any registration statement or other document pursuant to the Exchange Act or the Securities Act of 1933, as amended, unless otherwise indicated in such registration statement or other document.

+ Indicates management contract or compensatory plan or arrangement.

Copies of any of the exhibits filed with the SEC in connection with this document may be obtained from KCP&L upon written request. The registrants agree to furnish to the SEC upon request any instrument with respect to long-term debt as to which the total amount of securities authorized does not exceed 10% of total assets of such registrant and its subsidiaries on a consolidated basis.

Schedule I - Parent Company Financial Statements

GREAT PLAINS ENERGY INCORPORATED

Statements of Comprehensive Income (Loss) of Parent Company

Year Ended December 31	2017	2016	2015
Operating Expenses	(millions, except per share amounts)		
General and administrative	**$ 2.3**	$ 2.7	$ 0.9
Costs to achieve the anticipated merger with Westar Energy, Inc.	**16.1**	18.3	—
General taxes	**0.1**	0.1	0.2
Total	**18.5**	21.1	1.1
Operating loss	**(18.5)**	(21.1)	(1.1)
Other Income (Expense)			
Equity in earnings from subsidiaries	**141.4**	287.5	220.9
Non-operating income	**51.5**	31.3	29.7
Loss on extinguishment of debt	**(82.8)**	—	—
Loss on Series B Preferred Stock dividend make-whole provisions	**(124.8)**	—	—
Total	**(14.7)**	318.8	250.6
Interest (charges) income	**(125.6)**	2.6	(40.3)
Income (loss) before income taxes	**(158.8)**	300.3	209.2
Income tax (expense) benefit	**52.6**	(10.3)	3.8
Net income (loss)	**(106.2)**	290.0	213.0
Preferred stock dividend requirements and redemption premium	**37.3**	16.5	1.6
Earnings (loss) available for common shareholders	**$ (143.5)**	$ 273.5	$ 211.4
Average number of basic common shares outstanding	**215.5**	169.4	154.2
Average number of diluted common shares outstanding	**215.5**	169.8	154.8
Basic and diluted earnings (loss) per common share	**$ (0.67)**	$ 1.61	$ 1.37
Comprehensive Income			
Net income (loss)	**$ (106.2)**	$ 290.0	$ 213.0
Other comprehensive income			
Derivative hedging activity			
Reclassification to expenses	**0.4**	0.4	0.5
Income tax expense	**(0.1)**	(0.2)	(0.1)
Net reclassification to expenses	**0.3**	0.2	0.4
Derivative hedging activity, net of tax	**0.3**	0.2	0.4
Other comprehensive income from subsidiaries, net of tax	**4.1**	5.2	6.3
Total other comprehensive income	**4.4**	5.4	6.7
Comprehensive income (loss)	**$ (101.8)**	$ 295.4	$ 219.7

The accompanying Notes to Financial Statements of Parent Company are an integral part of these statements.

GREAT PLAINS ENERGY INCORPORATED

Balance Sheets of Parent Company

	December 31	
	2017	2016
ASSETS	(millions, except share amounts)	
Current Assets		
Cash and cash equivalents	**$ 1,114.2**	$ 1,283.9
Time deposit	**—**	1,000.0
Accounts receivable from subsidiaries	**34.8**	10.6
Notes receivable from subsidiaries	**2.0**	2.0
Interest rate derivative instruments	**91.4**	79.3
Other	**2.3**	26.1
Total	**1,244.7**	2,401.9
Investments and Other Assets		
Investment in KCP&L	**2,513.2**	2,541.5
Investment in other subsidiaries	**1,240.1**	1,341.6
Note receivable from subsidiaries	**634.9**	634.9
Deferred income taxes	**11.6**	12.8
Other	**1.0**	16.3
Total	**4,400.8**	4,547.1
Total	**$ 5,645.5**	$ 6,949.0
LIABILITIES AND CAPITALIZATION		
Current Liabilities		
Notes payable	**$ 11.0**	$ —
Current maturities of long-term debt	**—**	100.0
Accounts payable to subsidiaries	**21.7**	10.8
Accrued taxes	**—**	12.9
Accrued interest	**2.1**	10.1
Other	**5.9**	12.8
Total	**40.7**	146.6
Deferred Credits and Other Liabilities	**1.8**	2.2
Capitalization		
Great Plains Energy shareholders' equity		
Common stock - 600,000,000 shares authorized without par value 215,801,723 and 215,479,105 shares issued, stated value	**4,233.1**	4,217.0
Preference stock - 11,000,000 shares authorized without par value 7.00% Series B Mandatory Convertible Preferred Stock $1,000 per share liquidation preference, 0 and 862,500 shares issued and outstanding	**—**	836.2
Retained earnings	**737.9**	1,119.2
Treasury stock - 137,589 and 128,087 shares, at cost	**(4.0)**	(3.8)
Accumulated other comprehensive loss	**(2.2)**	(6.6)
Total shareholders' equity	**4,964.8**	6,162.0
Long-term debt	**638.2**	638.2
Total	**5,603.0**	6,800.2
Commitments and Contingencies		
Total	**$ 5,645.5**	$ 6,949.0

The accompanying Notes to Financial Statements of Parent Company are an integral part of these statements.

GREAT PLAINS ENERGY INCORPORATED
Statements of Cash Flows of Parent Company

Year Ended December 31	2017	2016	2015
Cash Flows from Operating Activities		(millions)	
Net income (loss)	$ (106.2)	$ 290.0	$ 213.0
Adjustments to reconcile income (loss) to net cash from operating activities:			
Amortization	26.2	30.4	0.8
Deferred income taxes, net	2.3	21.8	(1.7)
Equity in earnings from subsidiaries	(141.4)	(287.5)	(220.9)
Fair value impact of interest rate swaps	(12.1)	(79.3)	—
Loss on Series B Preferred Stock dividend make-whole provisions	124.8	—	—
Loss on extinguishment of debt	82.8	—	—
Cash flows affected by changes in:			
Accounts receivable from subsidiaries	(21.6)	(9.8)	(0.1)
Accounts payable to subsidiaries	10.9	(20.9)	1.3
Other accounts payable	(2.2)	7.0	—
Accrued taxes	(12.9)	8.4	0.3
Accrued interest	(8.0)	6.0	—
Cash dividends from subsidiaries	275.0	239.0	157.0
Other	22.3	8.0	8.7
Net cash from operating activities	239.9	213.1	158.4
Cash Flows from Investing Activities			
Purchase of time deposit	—	(1,000.0)	—
Proceeds from time deposit	1,000.0	—	—
Intercompany lending	—	—	(1.4)
Net money pool lending	—	3.7	(0.4)
Investment in subsidiary	(0.6)	(7.3)	(7.8)
Net cash from investing activities	999.4	(1,003.6)	(9.6)
Cash Flows from Financing Activities			
Issuance of common stock	2.9	1,603.7	3.0
Issuance of preferred stock	—	862.5	—
Issuance of long-term debt	4,291.9	—	—
Issuance fees	(32.2)	(143.4)	—
Repayment of long-term debt, including redemption premium	(4,443.0)	—	—
Net change in short-term borrowings	11.0	(10.0)	6.0
Dividends paid	(272.0)	(194.0)	(155.5)
Redemption of preferred stock	(963.4)	(40.1)	—
Other financing activities	(4.2)	(4.3)	(2.3)
Net cash from financing activities	(1,409.0)	2,074.4	(148.8)
Net Change in Cash and Cash Equivalents	(169.7)	1,283.9	—
Cash and Cash Equivalents at Beginning of Year	1,283.9	—	—
Cash and Cash Equivalents at End of Year	$ 1,114.2	$ 1,283.9	$ —

The accompanying Notes to Financial Statements of Parent Company are an integral part of these statements.

GREAT PLAINS ENERGY INCORPORATED
NOTES TO FINANCIAL STATEMENTS OF PARENT COMPANY

The Great Plains Energy Incorporated Notes to Consolidated Financial Statements in Part II, Item 8 should be read in conjunction with the Great Plains Energy Incorporated Parent Company Financial Statements.

The Great Plains Energy Incorporated Parent Company Financial Statements have been prepared to present the financial position, results of operations and cash flows of Great Plains Energy on a stand-alone basis as a holding company. Investments in subsidiaries are accounted for using the equity method.

Schedule II - Valuation and Qualifying Accounts and Reserves

Great Plains Energy Incorporated
Valuation and Qualifying Accounts
Years Ended December 31, 2017, 2016 and 2015

Description	Balance At Beginning Of Period	Additions: Charged To Costs And Expenses	Additions: Charged To Other Accounts	Deductions	Balance At End Of Period
Year Ended December 31, 2017			(millions)		
Allowance for uncollectible accounts	$ 4.0	$ 10.5	$ 8.1 (a)	$ 17.9 (b)	$ 4.7
Legal reserves	16.1	0.8	—	9.2 (c)	7.7
Environmental reserves	1.7	0.1	—	—	1.8
Tax valuation allowance	16.4	11.3	—	4.7 (d)	23.0
Year Ended December 31, 2016					
Allowance for uncollectible accounts	$ 3.8	$ 9.0	$ 8.1 (a)	$ 16.9 (b)	$ 4.0
Legal reserves	5.9	10.4	—	0.2 (c)	16.1
Environmental reserves	1.7	—	—	—	1.7
Tax valuation allowance	19.9	0.1	—	3.6 (d)	16.4
Year Ended December 31, 2015					
Allowance for uncollectible accounts	$ 2.8	$ 10.5	$ 8.7 (a)	$ 18.2 (b)	$ 3.8
Legal reserves	4.7	2.6	—	1.4 (c)	5.9
Environmental reserves	1.7	—	—	—	1.7
Tax valuation allowance	16.6	4.9	—	1.6 (d)	19.9

(a) Recoveries.
(b) Uncollectible accounts charged off.
(c) Payment of claims/settlements.
(d) Reversal of tax valuation allowance.

Kansas City Power & Light Company
Valuation and Qualifying Accounts
Years Ended December 31, 2017, 2016 and 2015

Description	Balance At Beginning Of Period	Additions: Charged To Costs And Expenses	Additions: Charged To Other Accounts	Deductions	Balance At End Of Period
Year Ended December 31, 2017			(millions)		
Allowance for uncollectible accounts	$ 1.8	$ 7.5	$ 5.6 [(a)]	$ 12.7 [(b)]	$ 2.2
Legal reserves	15.1	—	—	9.0 [(c)]	6.1
Environmental reserves	0.3	—	—	—	0.3
Tax valuation allowance	—	1.2	—	1.2 [(d)]	—
Year Ended December 31, 2016					
Allowance for uncollectible accounts	$ 1.8	$ 6.4	$ 5.5 [(a)]	$ 11.9 [(b)]	$ 1.8
Legal reserves	5.3	9.8	—	— [(c)]	15.1
Environmental reserves	0.3	—	—	—	0.3
Tax valuation allowance	0.7	—	—	0.7	—
Year Ended December 31, 2015					
Allowance for uncollectible accounts	$ 1.2	$ 7.1	$ 5.8 [(a)]	$ 12.3 [(b)]	$ 1.8
Legal reserves	2.9	2.6	—	0.2 [(c)]	5.3
Environmental reserves	0.3	—	—	—	0.3
Tax valuation allowance	—	0.7	—	—	0.7

(a) Recoveries.
(b) Uncollectible accounts charged off.
(c) Payment of claims/settlements.
(d) Reversal of tax valuation allowance.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

GREAT PLAINS ENERGY INCORPORATED

Date: February 21, 2018

By: /s/ Terry Bassham
Terry Bassham
Chairman, President and Chief Executive Officer

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

Signature	Title	Date
/s/ Terry Bassham Terry Bassham	Chairman, President and Chief Executive Officer (Principal Executive Officer)	February 21, 2018
/s/ Kevin E. Bryant Kevin E. Bryant	Senior Vice President - Finance and Strategy and Chief Financial Officer (Principal Financial Officer)	
/s/ Steven P. Busser Steven P. Busser	Vice President - Risk Management and Controller (Principal Accounting Officer)	
David L. Bodde*	Director	
Randall C. Ferguson, Jr.*	Director	
Gary D. Forsee*	Director	
Scott D. Grimes*	Director	
Thomas D. Hyde*	Director	
Ann D. Murtlow*	Director	
Sandra J. Price*	Director	
John J. Sherman*	Director	

*By /s/ Terry Bassham
Terry Bassham
Attorney-in-Fact*

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

KANSAS CITY POWER & LIGHT COMPANY

Date: February 21, 2018

By: /s/ Terry Bassham
Terry Bassham
Chairman, President and Chief Executive Officer

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

Signature	Title		Date
/s/ Terry Bassham Terry Bassham	Chairman, President and Chief Executive Officer (Principal Executive Officer)	)	
/s/ Kevin E. Bryant Kevin E. Bryant	Senior Vice President - Finance and Strategy and Chief Financial Officer (Principal Financial Officer)	)	
/s/ Steven P. Busser Steven P. Busser	Vice President - Risk Management and Controller (Principal Accounting Officer)	)	
David L. Bodde*	Director	)	
Randall C. Ferguson, Jr.*	Director	)	February 21, 2018
Gary D. Forsee*	Director	)	
Scott D. Grimes*	Director	)	
Thomas D. Hyde*	Director	)	
Ann D. Murtlow*	Director	)	
Sandra J. Price*	Director	)	
John J. Sherman*	Director	)	

*By /s/ Terry Bassham
Terry Bassham
Attorney-in-Fact*

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

FORM 10-K/A
(Amendment No. 1)

[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	Exact name of registrant as specified in its charter, state of incorporation, address of principal executive offices and telephone number	I.R.S. Employer Identification Number
001-32206	**GREAT PLAINS ENERGY INCORPORATED** (A Missouri Corporation) 1200 Main Street Kansas City, Missouri 64105 (816) 556-2200	43-1916803

Each of the following classes or series of securities registered pursuant to Section 12(b) of the Act is registered on the New York Stock Exchange:

Registrant	Title of each class
Great Plains Energy Incorporated	Common Stock, without par value

Securities registered pursuant to Section 12(g) of the Act: None.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Great Plains Energy Incorporated Yes X No _

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Great Plains Energy Incorporated Yes _ No 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.

Great Plains Energy Incorporated 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 (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Great Plains Energy Incorporated Yes X No _

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to the Form 10-K.

Great Plains Energy Incorporated 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. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Great Plains Energy Incorporated	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 Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Great Plains Energy Incorporated Yes _ No X

The aggregate market value of the voting and non-voting common equity held by non-affiliates of Great Plains Energy Incorporated (based on the closing price of its common stock on the New York Stock Exchange on June 30, 2017) was approximately $6,311,042,442.

On April 15, 2018, Great Plains Energy Incorporated had 215,795,884 shares of common stock outstanding.

Documents Incorporated by Reference

None.

EXPLANATORY NOTE

Great Plains Energy Incorporated (the “Company” or “Great Plains Energy”) is filing this Amendment No. 1 on Form 10-K/A (this “Amendment No. 1”) to amend its Annual Report on Form 10-K for the year ended December 31, 2017, originally filed with the Securities and Exchange Commission (the “SEC”) on February 21, 2018 (the “Original Filing”), to include the information required by Items 10 through 14 of Part III of Form 10-K. This information was previously omitted from the Original Filing in reliance on General Instruction G(3) to Form 10-K. This Amendment No. 1 consists solely of the preceding cover page, this explanatory note, the information required by Part III, Items 10, 11, 12, 13, and 14 of Form 10-K, a signature page and certifications required to be filed as exhibits.

The reference on the cover page of the Original Filing to the incorporation by reference of portions of our definitive proxy statement into Part III of the Original Filing related to Great Plains Energy is hereby deleted. In accordance with Rule 12b-15 under the Securities Exchange Act of 1934, as amended (the “Exchange Act”), Part III, including Items 10 through 14 of the Original Filing, solely as they relate to Great Plains Energy, is hereby amended and restated in its entirety.

This Amendment No. 1 does not reflect events occurring after the Original Filing, and, except as described above, does not modify or update any other disclosures. In particular, no changes have been made to the Original Filing with respect to Kansas City Power & Light Company (“KCP&L”), and this Form 10-K/A is not, and shall not be deemed to be an amendment of the Form 10-K filed by KCP&L as part of the Original Filing.

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PART III
ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

DIRECTORS

The names, ages and backgrounds, including the business experience, principal occupations and employment, of all directors of the Company are set forth below. Directors are elected to serve until the next annual meeting of the shareholders and until his or her successor shall be elected and qualified.

Terry Bassham Director since 2011

Mr. Bassham, 57, is Chairman of the Board (since May 2013), President (since May 2011) and Chief Executive Officer ("CEO") (since June 2012) of Great Plains Energy, KCP&L and KCP&L Greater Missouri Operations Company ("GMO"). He served as Chief Operating Officer of Great Plains Energy, KCP&L and GMO (2011-2012). He served as Executive Vice President-Utility Operations of KCP&L and GMO (2010-2011) and Executive Vice President-Finance and Strategic Development and Chief Financial Officer of Great Plains Energy (2005-2010) and of KCP&L and GMO (2009-2010). Mr. Bassham also currently serves on the board of Commerce Bancshares, Inc. (since 2013).

Mr. Bassham holds a Bachelor of Business Administration degree in accounting from the University of Texas-Arlington and a Juris Doctor degree from St. Mary's University Law School in San Antonio, Texas. Mr. Bassham has extensive regulated public utility experience with over 25 years in the industry. As President and CEO of the Company and the former Chief Operating Officer, he also brings to the Board deep insight and knowledge about the operations and capabilities of the Company.

David L. Bodde Director since 1994

Dr. Bodde, 75, is a Professor Emeritus effective 2017 at Clemson University (since 2004). He previously held the Charles N. Kimball Chair in Technology and Innovation (1996-2004) at the University of Missouri-Kansas City. He is a trustee of The Commerce Funds (since 1994). Prior to academic service, he was Vice President of the Midwest Research Institute and President of its subsidiary, MRI Ventures, Inc. Dr. Bodde serves as a member of the Company's Audit and Governance Committees. Dr. Bodde is also a director of KCP&L (since 1994) and GMO (since 2008).

Dr. Bodde holds a Bachelor of Science from West Point, Master of Science degrees in nuclear engineering and management from the Massachusetts Institute of Technology, and a Doctor of Business Administration degree from Harvard University. He has extensive experience in research, teaching, writing and consulting on energy policy, electric utility strategy, enterprise risk management, and technology assessment. His current work focuses on managing the risks of emerging energy technologies, especially related to electric utilities. His latest book, *Chance and Intent*, concerns managing the risks of innovation and entrepreneurship. His experience as a director provides valuable perspective and institutional knowledge to the Board's discussions and actions.

Randall C. Ferguson, Jr. Director since 2002

Mr. Ferguson, 66, was the Senior Partner for Business Development for Tshibanda & Associates, LLC (2005-2007), a consulting and project management services firm committed to assisting clients to improve operations and achieve long-lasting, measurable results. He previously served as Senior Vice President Business Growth & Member Connections with the Greater Kansas City Chamber of Commerce (2003-2005). Mr. Ferguson serves as a member of the Company's Compensation and Development and Governance Committees. Mr. Ferguson is also a director of KCP&L (since 2002) and GMO (since 2008).

Mr. Ferguson has extensive and varied senior management leadership experience and accomplishments gained through his 30-year career at IBM and at Tshibanda & Associates. He has broad strategic experience and insight into economic growth and policy through his prior leadership position at the Greater Kansas City Chamber of Commerce. Mr. Ferguson also brings a strong focus on the Company's community service and diversity activities. He has been recognized for his leadership and community service on numerous occasions, including recognition by *The Kansas City Globe* as one of Kansas City's most influential African Americans.

Gary D. Forsee Director since 2008

Mr. Forsee, 68, was President of the four-campus University of Missouri System (2008-2011). He previously served as Chairman of the Board (2006-2007) and CEO (2005-2007) of Sprint Nextel Corporation, and Chairman of the Board and CEO (2003-2005) of Sprint Corporation. He serves on the boards of Ingersoll-Rand Public Limited Company (since 2007) and DST Systems, Inc. (since 2015). Mr. Forsee serves as the Lead Director of the Board and as a member of the Company's Audit, Compensation and Development, and Governance Committees. Mr. Forsee is also a director of KCP&L and GMO (since 2008).

Mr. Forsee has extensive and varied senior management leadership experience and accomplishments gained as President of the University of Missouri System and through his more than 35-year telecommunications career at Sprint Nextel, BellSouth Corporation, Global One, AT&T and Southwestern Bell. Mr. Forsee's experience and insight acquired through managing large technologically complex and rapidly changing companies in dynamic regulatory environments is of particular value to the Company, which is facing similar challenges.

Scott D. Grimes Director since 2014

Mr. Grimes, 55, is Chief Executive Officer and Founder of Cardlytics, Inc. (since 2008), an international technology company that has pioneered card-linked marketing. Mr. Grimes previously served as Senior Vice President and General Manager, Payments (2005-2008) and as Vice President, Strategy (2003-2005) of Capital One Financial Corporation and Principal (2001-2003) at Canaan Partners. Mr. Grimes serves as a member of the Company's Audit and Compensation and Development Committees. Mr. Grimes is also a director of KCP&L and GMO (since 2014).

Mr. Grimes has extensive and varied senior management leadership experience and accomplishments gained as the Chief Executive Officer at Cardlytics, Inc. and a former executive at Capital One. As an entrepreneur and strategist, Mr. Grimes brings deep insight and entrepreneurial focus to the Company's strategic planning.

Thomas D. Hyde Director since 2011

Mr. Hyde, 69, served as Executive Vice President, Legal, Compliance, Ethics and Corporate Secretary of Wal-Mart Stores, Inc. ("Wal-Mart"), an international retail store operator (2005-2010). Mr. Hyde previously served as Executive Vice President, Legal and Corporate Affairs and Corporate Secretary of Wal-Mart (2003-2005), and as Executive Vice President, Senior General Counsel of Wal-Mart (2001-2003). Mr. Hyde served on the board of Vail Resorts, Inc. (2006-2012). He serves as a Trustee of the University of Missouri-Kansas City (since 2010). Mr. Hyde serves as a member of the Company's Audit and Governance Committees. Mr. Hyde is also a director of KCP&L and GMO (since 2011).

Mr. Hyde has extensive and varied senior management leadership experience and accomplishments gained through his career at Wal-Mart, and through such experience, he provides deep insight and understanding on corporate governance matters. Mr. Hyde graduated from the University of Kansas in 1970 with a degree in English. He received his Juris Doctor degree from the University of Missouri-Kansas City in 1975, and a Master of Business Administration degree in Finance from the University of Kansas in 1981.

Ann D. Murtlow Director since 2013

Ms. Murtlow, 57, is President and Chief Executive Officer of the United Way of Central Indiana (since 2013). Previously, she served as Principal of AM Consulting LLC (2011-2013). She served as Vice President and Group Manager of AES Corporation (1999-2011) and President, Chief Executive Officer and Director of Indianapolis Power & Light Company ("IPL") and IPALCO Enterprises (2002-2011), which are wholly-owned subsidiaries of AES Corporation. Ms. Murtlow currently serves on the boards of First Internet Bancorp and its subsidiary, First Internet Bank (since 2013), and Wabash National Corporation (since 2013). She previously served on the boards of the Federal Reserve Bank of Chicago (2007-2012), Herff Jones (2009-2015) and AEGIS Insurance Services, Inc. (2009-2011). Ms. Murtlow serves as a member of the Company's Audit and Governance Committees. Ms. Murtlow is also a director of KCP&L and GMO (since 2013).

Ms. Murtlow has extensive and varied senior management leadership experience and accomplishments gained through her career at AES Corporation and Bechtel Corporation. Her expertise acquired at IPL and IPALCO brings deep insight and knowledge about the operations and challenges of a vertically integrated, regulated electric utility. Ms. Murtlow has been named a Board Leadership Fellow by the National Association of Corporate Directors.

Sandra J. Price Director since 2016

Ms. Price, 59, is the former Senior Vice President, Human Resources of Sprint Corporation (2006 - 2016). Previously, she led the Human Resources, Communications and Brand Management functions of the Sprint Local Telephone Division and a variety of other human resources roles (1993-2006). Prior to Sprint, she was a principal in the Blue Valley School District, Overland Park, Kansas, and in the Jenks Public School District, Tulsa, Oklahoma. She currently serves as co-chair for KC Rising, a regional economic development initiative. Ms. Price serves as a member of the Company's Compensation and Development and Governance Committees. Ms. Price is also a director of KCP&L and GMO (since 2016).

Ms. Price has extensive and varied senior management leadership experience and accomplishments gained through her career. Her expertise acquired by leading all aspects of the Sprint human resources function and developing creative initiatives brings valuable depth to the Company's human capital perspective. Ms. Price was named to the Kansas City Business Journal's "Women Who Mean Business" list and to the Profiles in Diversity Journal's "Women Worth Watching."

John J. Sherman Director since 2009

Mr. Sherman, 63, is the vice chairman of the Cleveland Indians Baseball Club and a director of Crestwood Equity GP LLC (formerly known as Inergy GP, LLC). He was a director of Crestwood Midstream GP LLC (formerly known as NRGM GP, LLC) prior to its merger with Crestwood Equity GP, LLC. He formerly served as the Chief Executive Officer, President and Director of NRGM GP, LLC, general partner of Inergy Midstream, L.P. (2011-2013). He also served as Founder, Chief Executive Officer and Director of Inergy GP, LLC (the general partner of Inergy, L.P.) (2001-2013) and served as President, Chief Executive Officer and a director of Inergy Holdings GP, LLC (2005-2010). Mr. Sherman serves as a member of the Company's Audit and Compensation and Development Committees. Mr. Sherman is also a director of KCP&L and GMO (since 2009).

Mr. Sherman has extensive and varied senior management leadership experience, accomplishments and energy policy expertise gained through his career in the propane industry with Inergy, Dynegy, LPG Services Group (which he co-founded) and Ferrellgas. In addition to this expertise, Mr. Sherman brings a strong entrepreneurial focus to the Company's strategic planning.

CORPORATE GOVERNANCE

Audit Committee

The Company has an audit committee. The audit committee's current members are Messrs. Hyde (Chair), Forsee, Grimes and Sherman, Dr. Bodde and Ms. Murtlow. The Board has determined that all members of the committee are financially literate and that Messrs. Forsee, Grimes, Hyde, Sherman and Ms. Murtlow are "audit committee financial experts" as that term is defined by the SEC. The Board of Directors has determined that each of the members of the committee meets the experience and independence requirements of the rules of the New York Stock Exchange.

Code of Ethical Business Conduct

Lawful and ethical business conduct is required at all times. Our Board has adopted a Code of Ethical Business Conduct (the "Code"), which applies to our directors, officers and employees. Although the Code is designed to apply directly to our directors, officers and employees, we expect all parties who work on behalf of the Company to embrace the spirit of the Code. The Code is one part of our process to ensure lawful and ethical business conduct throughout the Company; other parts of the process include policies and procedures, compliance monitoring and reporting, and periodic training on various areas of the law and the Code. We have also established a ConcernsLine that can be accessed via a toll-free telephone number or through its website. The ConcernsLine is independently administered and is available 24 hours a day, every day, for the confidential and anonymous reporting of concerns and complaints by anyone inside or outside the Company. The ConcernsLine telephone number is listed in our Code.

The Code is available on the Company's website at *www.greatplainsenergy.com* and is also available in print to any shareholder upon request. Requests should be directed to Corporate Secretary, Great Plains Energy Incorporated, 1200 Main Street, Kansas City, MO 64105. The Company intends to disclose any change in the Code, or any waiver from a provision in the Code granted to a director or an executive officer, by posting such information on its website or by filing a Form 8-K. Information on, or that can be accessed through, the Company's website is not, and shall not be deemed to be, a part of this Amendment No. 1. or incorporated into any other filings the Company makes with the SEC.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires our directors, executive officers, and persons owning more than 10 percent of our common stock to file reports of holdings and transactions in our common stock with the SEC. Due to administrative error by the Company, Mr. Heidtbrink had one late Form 4 filing relating to an award of time-based restricted stock. Based upon our records, we believe that all other required reports for 2017 have been timely filed.

ITEM 11. EXECUTIVE COMPENSATION

COMPENSATION DISCUSSION AND ANALYSIS

Introduction

We are a public utility holding company, and our financial performance is driven by the performance of our two electric utility subsidiaries, KCP&L and GMO. Both subsidiaries are integrated electric utilities; that is, they generate, transmit and distribute electricity to their customers. KCP&L serves retail and wholesale customers in parts of Missouri and Kansas; GMO serves retail and wholesale customers in parts of Missouri.

Our compensation philosophy and decisions, which we explain below, are directly tied to our utility business. Our business is capital-intensive and subject to extensive and dynamic utility and environmental regulation. We operate in a technological environment that is complex and evolving. Our retail customer service areas and rates are fixed by the Missouri and Kansas utility commissions, which means that our financial health and growth potential are, in large part, directly tied to the communities we serve and the decisions of our regulatory commissions.

This Compensation Discussion and Analysis provides a comprehensive explanation of the compensation awarded to, earned by, or paid to the following individuals listed below, who are our named executive officers ("NEOs") for 2017:

- Terry Bassham, Chairman of the Board, President and Chief Executive Officer of Great Plains Energy, KCP&L and GMO;
- Kevin E. Bryant, Senior Vice President-Finance and Strategy and Chief Financial Officer of Great Plains Energy, KCP&L and GMO;
- Heather A. Humphrey, Senior Vice President-Corporate Services and General Counsel of Great Plains Energy, KCP&L and GMO;
- Lori A. Wright, Vice President-Corporate Planning, Investor Relations and Treasurer of Great Plains Energy, KCP&L and GMO;
- Charles A. Caisley, Vice President-Marketing and Public Affairs of Great Plains Energy, KCP&L and GMO; and
- Scott H. Heidtbrink, former Executive Vice President and Chief Operating Officer of KCP&L and GMO.

Mr. Heidtbrink retired from the Company effective May 1, 2017.

Committee Consideration of the Company's 2017 Shareholder Vote on Executive Compensation

At our May 2017 annual meeting, approximately 97 percent of our shareholders voting on the matter approved our 2016 executive compensation program. The Compensation and Development Committee (referred to throughout the "Compensation Discussion and Analysis" and "Executive Compensation" sections as the "Committee") believes this affirms the shareholders' support of the Company's approach to executive compensation, including our emphasis on pay for performance. The Committee decided that no significant changes to our executive compensation program were necessary for 2017.

Executive Summary of 2017 Compensation Decisions

2017 Performance Achievements

Our 2017 compensation decisions continued to be focused on **pay for performance –** the achievement of interrelated short-term and long-term objectives that are critical to our operations, financial health and growth. We believe a majority of each NEO's target compensation should be performance-based, or "at risk." Therefore, a significant portion of each NEO's compensation is tied to our total shareholder return ("TSR") and the achievement of Company-wide objectives for designated performance periods (see "2017 Compensation Decisions"). In order to align the interests of our NEOs with shareholder and customer interests, our executive compensation program provides more potential value to the NEOs through performance-based incentives than it does through base salary.

We believe that our focus on pay for performance helped motivate our NEOs and other officers throughout 2017. Through management's efforts, we achieved the following highlights, among others:

- **Executing strategy through proposed merger with Westar Energy, Inc. ("Westar")**

  In July 2017, we entered into an amended and restated agreement and plan of merger with Westar. By merging with Westar, we expect to build long-term value for our shareholders and cost savings for customers. Once the merger is complete, the combined company is expected to have more than 1.5 million customers in Kansas and Missouri, nearly 13,000 megawatts of owned generation capacity, almost 10,000 miles of transmission lines and over 52,000 miles of distribution lines. In addition, more than 45 percent of the combined utility's retail customer demand are expected to be met with emission-free energy.

  The transactions contemplated by our amended and restated merger agreement were approved by our shareholders in November 2017.

- **Investing to continue to meet the needs of our region in an environmentally conscientious manner**

  Federal and state agencies require us to comply with environmental and renewable energy mandates, and we have proactively responded to continue to meet the generation needs of our customers. In 2017, we announced retirement plans for six units at three power plants totaling 900 megawatts of capacity. The coal units are expected to be retired by the end of 2018 and the gas unit is expected to retired by the end of 2019. In addition, in 2017, we entered into two new wind power purchase agreements totaling 444 megawatts. This additional wind capacity will be generated at two new wind farms located in Kansas.

  In 2017, Kansas City made significant steps to adopting electric vehicles ("EVs"), which is helping transform the region into a premium location for EVs in the United States. KCP&L's Clean Charge Network is one of the nation's largest electric car charging networks and the first major network implemented by a public utility.

  The Company also published its first sustainability report, which is available on the Company's website at www.greatplainsenergy.com. All of these actions demonstrate our commitment to a sustainable future for our customers and our region.

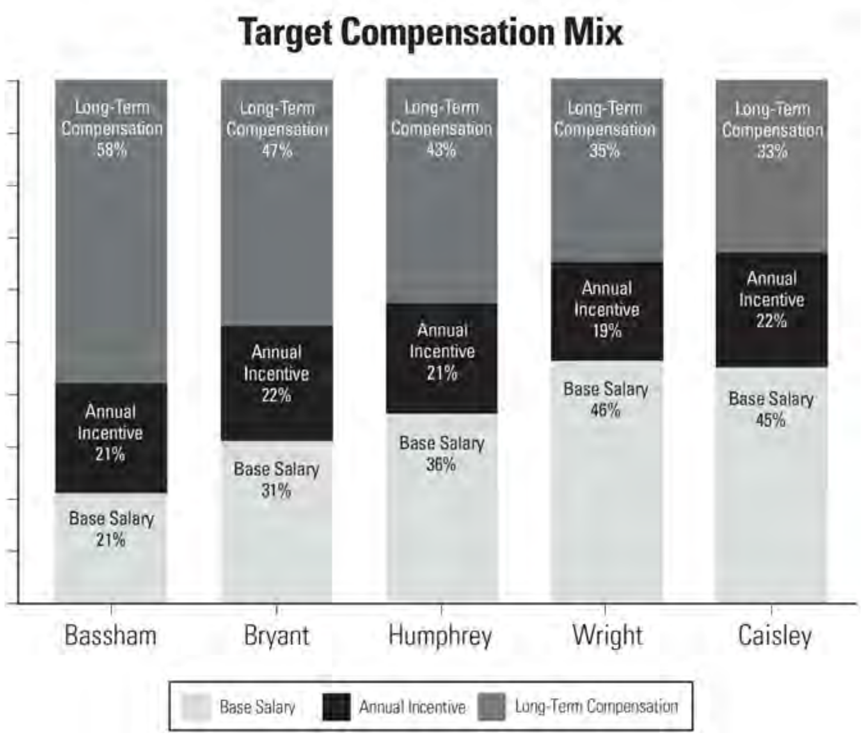
• **Continuing with our outstanding record of reliability**

KCP&L was again recognized by PA Consulting Group, Inc. as the recipient of the 2017 Outstanding Customer Reliability Experience Award and was also named as the recipient of the ReliabilityOne™ Award for Outstanding Reliability Performance in the Plains Region. Providing safe and reliable power for all of our customers continues to be a top priority for our employees and one of the foundations of KCP&L's operating strategy.

2017 Executive Compensation Decisions

The Committee and Board considered the achievements described above and made the following key executive compensation decisions:

• **Balanced Mix of Compensation Elements.** As in prior years, the Committee established, and the independent members of the Board approved, a mix of short-term and long-term compensation elements that reflected financial and operational goals and encouraged overall balanced performance to support sustainable shareholder value. The following chart shows the target pay mix of the 2017 direct compensation elements (base salary, annual incentive awards and long-term equity compensation awards) set out in the Summary Compensation Table on page 26 for each of our NEOs, except Mr. Heidtbrink, who retired from the Company effective May 1, 2017.



The compensation of each NEO also includes retirement benefits, generally available employee benefits, deferred compensation benefits and modest perquisites, as well as post-termination compensation.

• **Annual and Long-Term Performance Awards Tied to Achievement of Critical Objectives.** To align compensation with shareholder and customer interests, a significant portion of each NEO's compensation is tied to our short-term and long-term financial and operational performance.

Our 2017 annual incentive objectives and achievements were as follows:

2017 Annual Incentive Objectives	Weighting (Percent)	Achievement (Percent of Target)	Weighted Payout Percentage
Safety Audits & Training	10	150	15%
Equivalent Availability (Coal Units, Winter and Summer Peak Months)	10	61	6%
Equivalent Availability (Nuclear Only)	5	200	10%
System Average Interruption Duration Index (SAIDI) (minutes)	10	200	20%
Adjusted Earnings Per Share (excludes impact of proposed Westar merger and the initial impact of U.S. federal income tax reform)	50	144	72%
JD Power Customer Satisfaction Index (Residential Customer Satisfaction)	10	0	0%
Investment Across the Energy Value Chain that is Adjacent to our Existing Business	5	0	0%

The Company's total 2017 weighted scorecard achievement was 123 percent of target. Under the Annual Incentive Plan ("AIP"), the Company introduced an umbrella funding structure whereby if the primary earnings per share ("EPS") objective was achieved at the threshold performance level the AIP plan funds at the maximum level (200 percent of target), but the Committee retained discretion to exercise negative discretion to reduce the size of an individual's award (e.g., down to the actual scorecard achievement, or another amount between maximum and scorecard achievement). This umbrella structure was introduced to provide the Committee with maximum flexibility during a period of uncertainty surrounding the potential transaction with Westar (concerning both the length of the performance period and performance outcomes).

As a result of the officer team, including the NEOs, providing significant leadership during a lengthy period of uncertainty and their focus on delivering solid operational and financial results during this period, the Committee elected to exercise its discretion not to reduce the percentage payout from 200 percent down to the actual weighted scorecard achievement; accordingly each NEO, excluding Messrs. Bassham and Heidtbrink, received a 200 percent payout under the 2017 AIP. A discussion of the actual results of each objective starts on page 15.

Based on this successful performance, the following 2017 annual performance cash awards were paid to our NEOs:

Name	2017 Annual Incentive Award At Target (Percent of Annual Base Salary)	2017 Actual Award Paid (Percent of Annual Base Target)	2017 Actual Award Paid (Dollars)
Mr. Bassham	100	123	1,082,400
Mr. Bryant	70	200	646,800
Ms. Humphrey	60	200	495,600
Ms. Wright	40	200	248,800
Mr. Caisley	50	200	300,000
Mr. Heidtbrink[(1)]	70	—	—

(1) Mr. Heidtbrink retired from the Company effective May 1, 2017. Pursuant to the terms of a retirement agreement with the Company, Mr. Heidtbrink forfeited his 2017 annual incentive award. The terms of the agreement are more fully described under Other Agreements on page 23.

The Company had solid performance for the 2015-2017 performance period under the Long-Term Incentive Plan ("LTIP"). For the 2015-2017 performance period that ended on December 31, 2017, there was one performance objective: a TSR objective versus the Edison Electric Institute Index of Electric Utilities ("EEI Index"). The performance objective and actual results for the 2015-2017 performance period were as follows:

2015-2017 Performance Share Objective	Weighting (Percent)	Threshold (50%)	Target (100%)	Stretch (150%)	Superior (200%)	Actual Results	Achievement (Percentage of Target)
TSR versus EEI Index[(1)]	100%	30th Percentile	50th Percentile	70th Percentile	90th Percentile	38.1	70.25%

(1) TSR was compared to an industry peer group of the EEI Index of electric companies during the three-year measurement period 2015-2017. At the end of the three-year measurement period, we assessed our TSR compared to the EEI Index. Our NEOs received a percentage of the performance share grants based on performance. To appropriately balance our actual performance against our relative performance to the EEI Index, payout for the period was capped at target (100 percent) if our actual TSR performance was negative.

In 2017, we awarded a mix of performance shares (75 percent) and time-based restricted stock (25 percent) to retain and incentivize our NEOs. The performance share objective was:

2017-2019 Performance Share Objective	Weighting (Percent)
TSR versus EEI Index	100

A detailed summary of the 2017 long-term awards to each NEO starts on page 20. The restricted stock awards are expected to vest in 2020, and any performance shares received will be based on the level of achievement of the performance objective listed above. Following the closing of the Westar transaction, all awards will remain outstanding and will be based upon the level of achievement of the new combined company.

Compensation Governance Practices

The Committee is committed to high standards of corporate governance, as it works to establish an overall compensation program that aligns the interests of officers with the Company's shareholders. The following key compensation governance practices highlight this commitment:

- Committee Structure. The Committee is solely comprised of independent directors, and the Committee directly retains an independent compensation consultant, Mercer ("Mercer"), to regularly review and evaluate our compensation program.
- Stock Ownership Guidelines. We have significant stock ownership and holding guidelines for all of our executive officers. Our CEO is expected to hold an equity level of at least five times base salary. Other executive officers, including the other NEOs, are expected to hold equity that is either two or three times their base salaries.
- Clawback Policy. The Company may recover cash incentive compensation and equity awards from officers in the event of a restatement of or other inaccuracy in the Company's financial statements for a period of up to three years.
- Risk Assessment of Compensation Plans. We annually conduct a risk assessment to evaluate whether our compensation program creates any risks that may have a material adverse effect on the Company.
- Change in Control Benefit Triggers. Our Change in Control Severance Agreements have a "double trigger" and require both a change in control and termination for a qualifying event or circumstance such as being terminated without "cause" or leaving employment for "good reason."
- No Employment Contracts. We do not have employment contracts with any of our executive officers, including the NEOs.
- No Dividend Payments for Unvested Performance Shares. Dividends are not paid on unvested performance shares, unless and until such shares vest.
- Modest Perquisites. We provide modest perquisites that we believe provide a sound benefit to the Company.
- Alignment with Shareholder Interests. A significant portion of each executive officer's compensation is in the form of equity in an effort to align the economic interests of our executive officers with our shareholders.

Compensation Philosophy and Objectives

The primary objectives of our executive compensation program are to:

- Attract and Retain Qualified Leaders. Attract and retain highly qualified executive officers using a competitive pay package, with base salaries around the median level of comparable companies and opportunities for higher levels of compensation through time-based and performance-based incentives.
- Pay for Performance. Motivate executive officers to deliver a consistently high level of performance in the markets in which the Company operates, using incentives based on both short-term and long-term financial and operating results.
- Reward Long-Term Growth and Sustained Profitability. Align the economic interests of executive officers with those of our shareholders, by delivering a significant portion of total compensation in the form of time-based and performance-based equity awards based on incentive goals that, if achieved, are expected to increase TSR over the long term and contribute to the long-term success of the Company.
- Encourage Teamwork and Close Collaboration. Reward performance that encourages teamwork and close collaboration among executives which drives efficiencies for the benefit of customers and shareholders.

- Encourage Integrity and Ethics. Reward performance that supports the Company's Guiding Principles and Code of Ethical Business Conduct by promoting, instilling and striving to attain the highest standards in terms of a culture of integrity, business ethics and community service.

The Committee's Use of an Independent Compensation Consultant and Management's Role in the Executive Compensation Process

The Committee retains an independent compensation consultant to advise on executive and director compensation matters, assess the overall compensation program levels and elements, and evaluate competitive compensation trends. In 2017, the Committee retained Mercer to act as its independent compensation consultant. Mr. Michael Halloran, a Senior Partner at Mercer with more than 25 years of executive compensation experience, is the lead consultant who has worked with the Committee since 2008. The Committee retains the sole authority to select, retain, direct, or dismiss its compensation consultant. Our Corporate Secretary, in conjunction with other members of senior management, works directly with the compensation consultant to provide information, coordination and support. To assure independence, the Committee also pre-approves all other work unrelated to executive compensation proposed to be provided by Mercer if the fees would be expected to exceed $10,000. In February 2017, the Committee assessed the independence of Mercer and concluded that no conflict of interest exists that would prevent Mercer from independently representing the Committee.

In addition, beginning in 2017, members of management, including our Corporate Secretary, actively participated in the executive compensation review process with the assistance of management's compensation consultant, Willis Towers Watson ("WTW"). WTW worked with management to review, design, benchmark, and develop executive compensation information for review and consideration by the Committee's compensation consultant, the Committee, and the Board.

Role of Peer Group

Mercer recommends for Committee consideration peer group candidates with a size and business mix similar to ours. Potential peer group companies are assessed using three criteria: annual revenues, market value and percentage of total revenues from regulated electric operations. The Committee used the following peer group for the Committee's 2017 executive compensation decisions.

ALLETE, Inc.	Black Hills Corporation	PNM Resources, Inc.
Alliant Energy Corporation	IDACORP, Inc.	Portland General Electric Company
Ameren Corporation	NiSource Inc.	SCANA Corporation
AVANGRID	OGE Energy Corp.	Westar Energy, Inc.
Avista Corporation	Pinnacle West Capital Corporation	

When other surveys are used, Mercer conducts, where possible, regression analyses to adjust the compensation data for differences in the companies' revenues, allowing the Committee to compare compensation levels to similarly-sized companies.

The Compensation Review Process

Each year, the CEO provides to the Committee for consideration and review his performance self-assessment and development plan. This assessment is reviewed by the Committee and the Board and the Board provides feedback to the CEO. The CEO also provides compensation recommendations for all other executive officers. Such recommendations are based on a review and assessment of the (i) proxy data from the companies in our peer group, (ii) survey data and (iii) factors previously identified by the Committee, such as individual performance, time in position, scope of responsibility and experience.

The Committee also annually reviews a tally sheet for each NEO that shows each element of compensation and the total compensation paid to each NEO for the past two years. The tally sheets also show the equity awards granted and realized, and the amounts that would be payable to each NEO in the event of termination without cause and termination in connection with a change in control of the Company. This information provides the Committee with a clear picture of (i) how its decisions with respect to each element of compensation affect the total compensation package, (ii) how current compensation relates to compensation in the previous years and (iii) the total amount each NEO would receive, including the value of equity awards, under various termination scenarios. The Committee also reviews the total value of each NEO's proposed salary, target bonus and grant date value of equity awards for the year compared to the median total compensation of individuals in similar positions as described above. Total compensation for each NEO is generally targeted near the median of the market data for similar positions, while considering the factors above.

As a part of this review, the Committee also considers internal pay equity, both in terms of the total compensation of each executive officer compared to the CEO and within the officer group as compared to each other, considering individual responsibilities and experience levels. The Committee also evaluates the financial implications of compensation to mitigate financial inefficiencies to the greatest extent possible.

The Committee reviews these recommendations and corresponding information and makes final recommendations for Board approval.

Role of Executive Officers

While the CEO regularly attends meetings of the Committee, he is not a member and does not vote on Committee matters. In addition, there are portions of Committee meetings when the CEO is not present, such as when the Committee is in closed executive session or discusses the CEO's performance or individual compensation. The CEO's compensation levels and performance goals are recommended by the Committee for approval by the independent members of the Board. The CEO and other executive officers play a role in the early stages of design and evaluation of the Company's compensation programs and policies. Notwithstanding this limited involvement of executive officers, all compensation decisions are ultimately recommended by the Committee and approved by the independent members of the Board.

Summary and Analysis of Executive Compensation

Consistent with prior years, the elements of executive compensation were: (1) cash compensation in the form of base salaries, annual incentives and discretionary cash awards; (2) equity compensation under our LTIP; (3) deferred compensation; (4) retirement benefits; (5) post-termination compensation; and (6) modest perquisites and generally available employee benefits.

Compensation Component	Description	Objective
Cash Compensation		
Base Salary	• Fixed compensation that is reviewed annually taking into consideration peer compensation information, as well as individual performance. • Competitively aligned with median market salary.	• Provide a fixed level of compensation that fairly considers job responsibilities, level of experience, internal and external comparisons and individual performance evaluations. • Attract and retain talent.
Annual Incentives under AIP	• Variable compensation earned based on performance of pre-established annual objectives and targets.	• Reward the achievement of annual financial and operating objectives that ultimately contribute to long-term value for shareholders and customers.
Discretionary Cash Awards	• Discretionary cash awards for significant achievements.	• Reward individual performance and/or aid in retention. • Attract talent.
Equity Compensation		
Performance Shares and Restricted Stock Grants under the LTIP	• Performance shares that are paid based on achievement of three-year performance objectives. • Time-based restricted stock, generally vesting over three years.	• Motivate performance that creates long-term value to shareholders and customers. • Align the economic interests of participants with shareholders and customers by rewarding executives for financial and operational achievements. • Build stock ownership. • Provide a competitive total package to attract and retain executives.
Discretionary Stock Awards	• Discretionary stock awards for significant achievements.	• Reward individual performance and/or aid in retention.
Deferred Compensation		
Benefits	• A non-qualified and unfunded plan that allows all officers, including NEOs, to defer the receipt of up to 50 percent of base salary and 100 percent of awards under the AIP.	• Provide compensation deferrals in a tax-efficient manner.

Compensation Component	Description	Objective
Retirement Benefits		
Pension Plan	• Funded, tax-qualified, noncontributory defined benefit plan for all employees, including NEOs. This plan is not available to any non-union employee, including any officer hired after December 31, 2013.	• Provide a competitive total package to retain executives and other employees. • Provide some retirement income security in a tax efficient manner.
SERP	• An unfunded plan that provides additional retirement income to all executives, including NEOs. This plan is not available to any executive hired after December 31, 2013.	• Provide a competitive total package to retain executives. Provide additional supplemental retirement income.
401(k) Plan	• Tax-qualified retirement savings plan provided to all employees, including NEOs.	• Provide retirement savings in a tax efficient manner. • Provide a competitive total package to attract and retain executives and other employees.
Other Post-termination Compensation		
Change in Control Severance Agreements	• Payments and other benefits in the event of (i) change in control and (ii) termination of employment.	• Encourage executives to act in the best interests of shareholders and customers in times of fundamental change and uncertainty. • Aid in recruitment and retention.
Perquisites and Generally Available Employee Benefits		
Benefits	• Limited perquisites that are consistent with peer companies. Benefits include financial planning services and executive health physicals. • General employee benefits, such as medical benefits, life insurance, and disability benefits.	• Provide a competitive total package to attract and retain key talent.

Cash Compensation

Cash compensation to our NEOs includes a market-competitive base salary, performance-driven annual incentives and, from time to time, discretionary cash awards. The Committee believes total compensation to be delivered in cash or cash opportunities should vary based on each NEO's position and circumstance, and that, in general, the level of cash opportunity should decrease in proportion to equity compensation as officers move to higher levels of responsibility.

Base Salary

Base salaries are reviewed annually. The Committee considers performance evaluations and base salary recommendations submitted by the CEO for the NEOs other than himself. The CEO's performance evaluation is reviewed by the Committee and then reviewed and approved by the Board. Salary recommendations are not determined by formula, but instead take into consideration job responsibilities, level of experience, internal comparisons, comparisons to the salaries of executives in similar positions at similar companies obtained from market surveys, other competitive data and input provided by Mercer, and individual performance evaluations. Individual performance evaluations include major accomplishments during the performance period, as well as qualitative factors, including personal leadership, engagement of employees, disciplined performance management, accountability for results, and community involvement.

The 2017 base salaries of the NEOs are as follows:

Name	2017 Base Salary
Mr. Bassham	$880,000
Mr. Bryant	$462,000
Ms. Humphrey	$413,000
Ms. Wright	$311,000
Mr. Caisley	$300,000
Mr. Heidtbrink[(1)]	$570,000

(1) Mr. Heidtbrink retired from the Company effective May 1, 2017.

Annual Incentives

The Company's AIP for all executive officers is based upon a mix of Company-wide financial and operational metrics. The Committee believes that the AIP continues to focus the Company on, and reward executives for, delivering key financial results, strategic business outcomes, and exceptional performance. For 2017, the Company utilized an "umbrella" funding structure for granting annual incentive awards under the AIP. Under this umbrella funding structure, if the primary EPS objective was achieved at the threshold performance level, the AIP awards were funded at the maximum level, subject to reduction based on the Company's level of achievement of other secondary Company objective "scorecard" goals. This annual incentive structure provided the Committee with the ability to exercise negative discretion and to differentiate bonus amounts among officers based on individual performance and achievements and the Committee's assessment of the individual's overall contributions to the Company.

The Committee established target incentives for each NEO as a percentage of base pay, using survey data provided by Mercer for comparable positions and markets, as well as comparisons for internal equity. The basic structure of the AIP provided for individual maximum payout of 200 percent if the Company's scorecard goal was achieved at the superior level of objective performance, followed by reduction down to a 100 percent payout if achievement was obtained at the target level of objective performance and a reduction down to 50 percent payout if achievement was obtained at the threshold level of objective performance. Following the application of the Committee's negative discretion, no officer received less than the amounts he or she was eligible to receive based on scorecard performance; however, an officer could receive more than the actual scorecard performance amount based solely on the Committee's discretionary evaluation of individual performance and overall contributions to the Company. No awards could exceed the total individual maximum payout amount of 200 percent of target. Objective scorecard performance was interpolated between the threshold, target and maximum performance levels. Objective scorecard performance achievement on EPS that was less than threshold achievement would result in a zero payment.

The 2017 AIP results are shown in the following table:

2017 Annual Incentive Objectives	Weighting (Percent)	Threshold 50%	Target 100%	Stretch 150%	Superior 200%	Actual Performance Result	Weighted Payout Percentage	Achievement (Percent of Target)
Safety Audits & Training(1)	10	See footnote.(1)				See Stretch footnote.(1)	15%	150%
Equivalent Availability (Coal Units, Winter and Summer Peak Months)	10	75.5%	83.9%	85.8%	87.6%	77.3%	6%	61%
Equivalent Availability (Nuclear Only)	5	80.0%	97.0%	98.1%	99.3%	99.9%	10%	200%
System Average Interruption Duration Index (SAIDI) (minutes)	10	96.75	86.09	84.20	82.32	70.77	20%	200%
Adjusted EPS (excludes impact of Westar merger and the initial impact of U.S. federal income tax reform)	50	$1.50	$1.67	$1.75	$1.84	$1.74	72%	144%
JD Power Customer Satisfaction Index (Residential Customer Satisfaction)	10	Ranked 10 out of 16	Ranked 9 out of 16	Ranked 8 out of 16	Ranked 7 out of 16	Ranked 11 out of 16	0%	0%
Investment Across the Energy Value Chain that is Adjacent to our Existing Business(2)	5	See footnote.(2)				(1) $7 Million Investment in GXP Investments, Inc. (an investment subsidiary) (“GXPI”) and (2) $2.3 Million Investment in Transource Energy, LLC (“Transource”)	0%	0%
	100	Weighted Achievement %					123%	123%

(1)

Threshold 50%	Target 100%	Stretch 150%	Superior 200%
(1) Company-wide safety training 100 percent complete; (2) 1.5 safety and health self-audits completed per month with 95.0 percent of related correction plans to be completed within 45 days or plan to achieve; and (3) 9 Physical Conditions Audits with 95.0 percent of related correction plans to be completed within 45 days or a plan to achieve.	(1) Company-wide safety training 100 percent complete; (2) 2 safety and health self-audits completed per month with 97.5 percent of related correction plans to be completed within 45 days or plan to achieve; and (3) 12 Physical Conditions Audits with 97.5 percent of related correction plans to be completed within 45 days or a plan to achieve.	(1) Company-wide safety training 100 percent complete; (2) 2.5 safety and health self-audits completed per month with 100 percent of related correction plans to be completed within 45 days or plan to achieve; and (3) 18 Physical Conditions Audits with 100 percent of related correction plans to be completed within 45 days or a plan to achieve.	(1) Company-wide safety training 100 percent complete; (2) 4 safety and health self-audits completed per month with 100 percent of related correction plans to be completed within 45 days or plan to achieve; and (3) 24 Physical Conditions Audits with 100 percent of related correction plans to be completed within 45 days or a plan to achieve.

(2)

Threshold 50%	Target 100%	Stretch 150%	Superior 200%
(1) $15.0 million in investment by GXPI and (2) $2.4 million investment in Transource.	(1) $18.0 million investment by GXPI and (2) $2.7 million investment in Transource.	(1) $19.0 million investment by GXPI and (2) $2.9 million investment in Transource.	(1) $20.0 million investment by GXPI and (2) $3.1 million investment in Transource.

Individual targets and awards earned by each of the NEOs are shown below and in the Summary Compensation Table on page 26.

Name	2017 Annual Incentive Award at Target (Percent of Annual Base Salary)	2017 Actual Award Paid (Percent of Annual Base Target) (1)	2017 Actual Award Paid (Dollars)
Mr. Bassham	100	123	1,082,400
Mr. Bryant	70	200	646,800
Ms. Humphrey	60	200	495,600
Ms. Wright	40	200	248,800
Mr. Caisley	50	200	300,000
Mr. Heidtbrink(2)	70	—	—

(1) As a result of the officer team, including the NEOs, providing significant leadership during a lengthy period of uncertainty and their focus on delivering solid operational and financial results during this period, the Committee elected to exercise its discretion not to reduce the percentage payout from 200 percent down to the actual weighted scorecard achievement; accordingly each NEO, excluding Messrs. Bassham and Heidtbrink, received a 200 percent payout under the 2017 AIP.

(2) Mr. Heidtbrink retired from the Company effective May 1, 2017. Pursuant to the terms of a retirement agreement with the Company, Mr. Heidtbrink forfeited his 2017 annual incentive award. The terms of the agreement are more fully described under Other Agreements on page 23.

Discretionary Cash or Stock Awards

From time to time, the Committee may grant a discretionary cash or stock award for special accomplishments or achievements. No discretionary cash or stock awards were made in 2017.

Equity Compensation

We believe that a significant portion of NEO compensation should be in the form of equity in order to best align executive compensation with the interests of our shareholders. Equity awards, which are made under our shareholder approved LTIP, are generally targeted near the median range of officers in companies of similar size in the industry.

The Committee uses a mix of time-based restricted stock and performance shares that are paid solely on the basis of the attainment of performance goals. Performance shares can be earned at the end of the performance period from 0 percent to 200 percent of the target amount, depending on actual performance. Payment for performance shares must generally be made in shares of Company common stock. However, the Committee, in its sole discretion, may authorize payment in such combination of cash and shares, or all cash as it deems appropriate. Performance results for a goal that are less than threshold will result in a zero payment for that goal.

Dividend equivalents on the number of performance shares actually earned are paid in cash at the same time as the vesting of the earned performance shares. Dividends accrued on all restricted stock awards are reinvested during the period under the Company’s Dividend Reinvestment and Direct Stock Purchase Plan, and are subject to the same restrictions as the associated restricted stock.

While our NEOs are eligible for equity awards under the LTIP, none of them has any right to be granted awards.

The performance share metrics discussed below have been established for compensation purposes only. They do not constitute any guidance, projection or estimate of these measures, and should not be relied upon for any purpose other than understanding our compensation program.

2015-2017 Performance Period

For the three-year performance period ended December 31, 2017, the Board, upon the recommendation of the Committee, modified the performance objectives under the LTIP prior to the commencement of the 2015-2017 performance period. Previously, the Board utilized two equally-weighted performance share objectives (i) a credit objective (three-year average Funds from Operations (“FFO”) to Total Adjusted Debt) and (ii) a total shareholder return objective (TSR versus EEI Index). However, for the 2015-2017 performance period, there was one performance objective, total shareholder return (TSR versus EEI Index). The Committee believed that this change better aligned each officer’s performance with the interests of shareholders and focused the Company’s leadership team on our strategic initiatives to increase stock price and dividend growth. Consistent with the 2014-2016 performance period, the Committee established the distribution between performance shares and restricted stock at 75 percent/25 percent, respectively.

Additionally, to better align with market and industry practices, specific performance targets were set with interpolation between the targets. To appropriately balance our actual performance against our relative performance to the EEI Index, any potential payout for the period would be capped at Target (100 percent) if actual TSR performance was negative.

Consistent with prior years, performance share and restricted stock awards for the 2015-2017 performance period were based on percentages of 2015 base salary. The percentages of 2015 base salary (reflecting the target amount of awards) were as follows: Mr. Bassham, 270 percent; Mr. Bryant, 120 percent; Ms. Humphrey, 120 percent; Ms. Wright, 75 percent; Mr. Caisley, 75 percent; and Mr. Heidtbrink, 175 percent.

The 2015-2017 performance period objective and criteria were as follows:

2015-2017 Performance Share Objective	Weighting (Percent)	Threshold (50%)	Target (100%)	Stretch (150%)	Superior (200%)	Actual Results	Weighted Payout Percentage
TSR versus EEI Index(1)	100%	30th Percentile	50th Percentile	70th Percentile	90th Percentile	38.1	70.25%

(1) TSR was compared to an industry peer group of the EEI Index of electric companies during the three-year measurement period 2015-2017. At the end of the three-year measurement period, we assessed our TSR compared to the EEI Index. The officers received a percentage of the performance share grants based on performance. To appropriately balance our actual performance against our relative performance to the EEI Index, payout for the period was capped at target (100 percent) if actual TSR performance was negative.

Based upon the results above, performance share awards for the 2015-2017 performance period for each of the NEOs are shown below:

Name	Value of Actual Award Paid ($)(1)
Mr. Bassham	1,091,621
Mr. Bryant(2)	223,766
Ms. Humphrey	252,862
Ms. Wright	127,052
Mr. Caisley	123,093
Mr. Heidtbrink(3)	—

(1) In addition, cash dividend equivalents were paid after the end of the performance period, as follows: Mr. Bassham ($116,775), Mr. Bryant ($23,937), Ms. Humphrey ($27,050), Ms. Wright ($13,591), and Mr. Caisley ($13,168).

(2) On September 2, 2015, Mr. Bryant became the Senior Vice President-Finance and Strategy and Chief Financial Officer. Mr. Bryant's target was increased to 120 percent on a prorated basis. In conjunction with his promotion, Mr. Bryant received additional restricted stock and performance share awards.

(3) Mr. Heidtbrink retired from the Company effective May 1, 2017. Pursuant to the terms of a retirement agreement with the Company, Mr. Heidtbrink received all his restricted shares and a prorated number of performance share awards for the 2015-2017 performance period. The terms of the agreement are more fully described under Other Agreements on page 23.

2016-2018 Performance Period

For the three-year performance period ending December 31, 2018, the performance objective is the same as the performance objective for the 2015-2017 performance period. There is one performance objective, total shareholder return (TSR versus EEI Index). To continue to focus on performance, the Board, upon the recommendation of the Committee, established the distribution between performance shares and restricted stock at 75 percent/25 percent, respectively. Similar to the 2015-2017 performance period, specific performance targets were set with interpolation between the targets. To appropriately balance our actual performance against our relative performance to the EEI Index, any potential payout for the period will be capped at Target (100 percent) if actual TSR performance is negative.

Consistent with prior years, performance share and restricted stock awards for the 2016-2018 performance period are based on percentages of 2016 base salary. The percentages of 2016 base salary (reflecting the target amount of awards) are as follows: Mr. Bassham, 270 percent; Mr. Bryant, 120 percent; Ms. Humphrey, 120 percent; Ms. Wright, 75 percent; Mr. Caisley, 75 percent; and Mr. Heidtbrink, 175 percent. This resulted in the following long-term incentive grants in 2016 of time-based restricted stock and performance shares, which may be paid after the end of the period depending on performance:

Name	Restricted Stock[1]	Performance Shares (at target)[1]
Mr. Bassham	18,538	55,613
Mr. Bryant	4,141	12,421
Ms. Humphrey	4,048	12,143
Ms. Wright	1,906	5,716
Mr. Caisley	1,841	5,523
Mr. Heidtbrink[2]	8,156	24,466

(1) The restricted stock grants vest on March 1, 2019; the cash and common stock payments related to the performance shares, if any, will also occur on March 1, 2019. Actual performance shares may be between 0 percent and 200 percent of the target number of shares.

(2) Mr. Heidtbrink retired from the Company effective May 1, 2017. Pursuant to the terms of a retirement agreement with the Company, Mr. Heidtbrink received all his restricted stock and a prorated number of performance shares for the 2016-2018 performance period. The terms of the agreement are more fully described under Other Agreements on page 23.

The 2016-2018 performance period objective and criteria are as follows:

2016-2018 Performance Share Objective	Weighting (Percent)	Threshold (50%)	Target (100%)	Stretch (150%)	Superior (200%)
TSR versus EEI Index[1]	100%	30th Percentile	50th Percentile	70th Percentile	90th Percentile

(1) TSR is compared to an industry peer group of the EEI Index of electric companies during the three-year measurement period 2016-2018. At the end of the three-year measurement period, we will assess our TSR compared to the EEI Index. Depending on how we rank, the officers will receive a percentage of the performance share grants. To appropriately balance our actual performance against our relative performance to the EEI Index, any payout for the period would be capped at Target (100 percent) if actual TSR performance is negative.

Following the closing of the Westar transaction, all awards will remain outstanding and will be based upon the level of achievement of the new combined company.

2017-2019 Performance Period

For the three-year performance period ending December 31, 2019, the performance objective is the same as the performance objective for the 2016-2018 performance period. There is one performance objective, total shareholder return (TSR versus EEI Index). To continue to focus on performance, the Board, upon the recommendation of the Committee, established the distribution between performance shares and restricted stock at 75 percent/25 percent, respectively. Similar to the 2016-2018 performance period, specific performance targets were set with interpolation between the targets. To appropriately balance our actual performance against our relative performance to the EEI Index, any potential payout for the period will be capped at Target (100 percent) if actual TSR performance is negative.

Consistent with prior years, performance share and restricted stock awards for the 2017-2019 performance period were based on percentages of 2017 base salary. The percentages of 2017 base salary (reflecting the target amount of awards) were as follows: Mr. Bassham, 270 percent; Mr. Bryant, 150 percent; Ms. Humphrey, 120 percent; Ms. Wright, 75 percent; Mr. Caisley, 75 percent; and Mr. Heidtbrink, 175 percent. This resulted in the following long-term incentive grants in 2017 of time-based restricted stock and performance shares, which may be paid after the end of the period depending on performance:

Name	Restricted Stock(1)	Performance Shares (at target)(1)
Mr. Bassham	20,547	61,640
Mr. Bryant	5,993	17,979
Ms. Humphrey	4,286	12,858
Ms. Wright	2,018	6,052
Mr. Caisley	1,946	5,838
Mr. Heidtbrink(2)	8,626	25,878

(1) The restricted stock grants vest on March 2, 2020; the cash and common stock payments related to the performance shares, if any, will also occur on March 2, 2020. Actual performance shares may be between 0 percent and 200 percent of the target number of shares.

(2) Mr. Heidtbrink retired from the Company effective May 1, 2017. Pursuant to the terms of a retirement agreement with the Company, Mr. Heidtbrink forfeited his restricted stock and performance share awards for the 2017-2019 performance period. The terms of the agreement are more fully described under Other Agreements on page 23.

The 2017-2019 performance period objective was as follows:

2017-2019 Performance Share Objective	Weighting (Percent)	Threshold (50%)	Target (100%)	Stretch (150%)	Superior (200%)
TSR versus EEI Index(1)	100%	30th Percentile	50th Percentile	70th Percentile	90th Percentile

(1) TSR is compared to an industry peer group of the EEI Index of electric companies during the three-year measurement period 2017-2019. At the end of the three-year measurement period, we will assess our TSR compared to the EEI Index. Depending on how we rank, the officers will receive a percentage of the performance share grants. To appropriately balance our actual performance against our relative performance to the EEI Index, any payout for the period would be capped at Target (100 percent) if actual TSR performance is negative.

Following the closing of the Westar transaction, all awards will remain outstanding and will be based upon the level of achievement of the new combined company.

2017 Equity Vesting, Payments and Special Grants

The restricted stock and performance share awards under the 2014-2016 LTIP performance period for the NEOs vested in 2017. In connection with his appointment as Senior Vice President-Finance and Strategy and Chief Financial Officer, Mr. Bryant was awarded a special one-time retention grant of 12,346 shares of restricted stock on September 2, 2015. Thirty-four percent of these shares vested on September 2, 2016, 33 percent vested on September 5, 2017 and 33 percent vest on September 4, 2018. The following table summarizes these grant vestings and payments:

Name	2017 Vesting of Restricted Stock (# shares)(1)	2014-2016 Performance Share Payments (# shares)(2)	Total Number of Shares Acquired at Vesting
Mr. Bassham(3)	27,530	51,610	79,140
Mr. Bryant(4)	9,195	5,944	15,139
Ms. Humphrey(3)	6,994	12,083	19,077
Ms. Wright	2,233	5,997	8,230
Mr. Caisley	2,186	5,866	8,052
Mr. Heidtbrink(3)(5)	34,031	54,626	88,657

(1) The amounts shown for restricted stock vestings include reinvested dividends related to the underlying restricted stock grants.

(2) The shares shown in this column are the earned amounts of performance shares for the 2014-2016 performance period, which were paid in 2017. Dividend equivalents over the performance period were paid in cash at the time of payment of the underlying performance shares. As permitted by our LTIP, the earned performance shares were paid in a combination of cash for the cash dividend equivalent, (which was used to satisfy withholding tax obligations) and common stock.

(3) Amounts include a one-time discretionary grant award of restricted stock and reinvestment dividends that vested in March 2017.

(4) Amounts for Mr. Bryant include the special one-time award of restricted stock and reinvested dividends that vested in September 2017.

(5) Mr. Heidtbrink retired from his position as Executive Vice President and Chief Operating Officer of KCP&L effective May 1, 2017.

Deferred Compensation

The Company's non-qualified deferred compensation plan ("DCP") allows all officers, including NEOs, to defer the receipt of up to 50 percent of base salary and 100 percent of any cash incentive award. The earnings rate on deferral amounts is annually determined by the Committee and based on the Company's weighted average cost of capital. A detailed discussion of the DCP begins on page 35.

Retirement Benefits

Pension Plan and Supplemental Executive Retirement Plan

The Company maintains a funded, tax-qualified, noncontributory defined benefit plan (the "Pension Plan") for all non-union employees hired or rehired on or before December 31, 2013, including NEOs. Benefits under the Pension Plan are based on each employee's years of service and the average annual base salary over a specified period.

The Company also has an unfunded Supplemental Executive Retirement Plan ("SERP") for its executives, including all NEOs. This unfunded plan provides the difference between the amount that would have been payable under the Pension Plan in the absence of Internal Revenue Service tax code limitations and the amount actually payable under the Pension Plan. It also provides a slightly higher benefit accrual rate than the Pension Plan. All executives hired or rehired on or before December 31, 2013, including NEOs, are eligible to participate in the SERP.

In 2007, non-union employees of Great Plains Energy and KCP&L, including the NEOs, were given a one-time election to remain in their existing Pension Plan and 401(k) Plan ("Old Retirement Plan"), or choose a new retirement program that includes a slightly reduced benefit accrual formula under the Pension Plan paired with an enhanced benefit under the 401(k) Plan ("Current Retirement Plan"). Messrs. Bassham, Bryant, and Caisley and Mses. Humphrey and Wright elected to participate in the Current Retirement Plan. Mr. Heidtbrink joined the Company subsequent to 2007 and participates in the Current Retirement Plan.

401(k) Plan

Our 401(k) Plan is offered to all employees as a tax-qualified retirement savings plan.

- Employees in the Old Retirement Program can contribute up to 40 percent of base pay. After one year of employment, the Company matches 50 percent of the first 6 percent of base pay that is contributed. Employees are fully vested in the Company matching contribution and associated earnings after six (6) years.
- Employees in the Current Retirement Program can contribute up to 75 percent of base pay, bonus incentive, and overtime pay. The Company matches 100 percent of the first 6 percent of total pay that is contributed. Company contributions vest immediately.
- Employees hired on or after January 1, 2014 are eligible to participate in the new Retirement Program Plus. In this program, employees can contribute up to 75 percent of base pay, bonus incentive, and overtime pay. The Company matches 100 percent of the first 6 percent of total pay that is contributed and contributes an annual non-elective amount equal to 4 percent of employee base pay. The Company matching contribution vests immediately and the annual non-elective contribution and associated earnings vest after three (3) years of service.
- Contributions are limited by the tax code.

Other Post-termination Compensation

The Company has entered into change in control agreements with its executive officers, including NEOs, to encourage their continued employment and dedication when an executive may have concerns about their continued employment. The Company believes these agreements and benefits are important recruitment and retention devices. The Company has historically authorized certain agreements with retiring officers to ensure a smooth transition.

Change in Control Severance Agreements

We have change in control agreements with all of our executive officers, including the NEOs, to ensure their continued service, dedication, and objectivity in the event of a transaction that would result in a change in control of the Company. These agreements support the objective assessment and execution of potential changes in the Company's strategy and enhance retention by reducing concerns about employment continuity. These agreements provide for payments and other benefits if the officer's employment terminates for a qualifying event or circumstance, such as being terminated without "Cause" or leaving employment for "Good Reason," as these terms are defined in the agreements. All the agreements require a double trigger so that both a change in control and a termination (actual or constructive) of the executive's employment must occur to trigger benefits. Generally, the Committee and Board determined the eligibility for potential payments upon change in control, based on comparable practices in the market.

Additional information, including a quantification of benefits that would have been received by NEOs had termination occurred on December 31, 2017, is found under the heading "Potential Payments Upon Termination or Change in Control" starting on page 35.

Other Agreements

None of the Company's executive officers, including the NEOs, have a written employment agreement. However, in May 2017, the Company entered into a retirement agreement with Mr. Heidtbrink in connection with his retirement from the Company. The agreement provided for, among other things: (a) the forfeiture of restricted stock and performance share grants made in 2017 to Mr. Heidtbrink; (b) the vesting of restricted stock grants made to Mr. Heidtbrink prior to 2017; (c) vesting of all performance share awards granted prior to 2017 to be paid on a pro rata basis; and (d) a general cross-release of claims. The value of the restricted stock and performance shares that vested on Mr. Heidtbrink's retirement date was $1,407,671. In addition, the agreement provided for a bonus of $302,827 paid upon Mr. Heidtbrink's retirement.

Perquisites and Generally Available Employee Benefits

Our NEOs are eligible to receive minimal perquisites provided by or paid for by the Company. These perquisites are generally consistent with those offered to executives at comparable organizations with which the Company competes for executive talent and are important for retention and recruitment. The NEOs are also eligible for employment benefits that are generally available to all employees, such as vacation and medical and life insurance.

As shown in the Summary Compensation Table on page 26, all NEOs are eligible for participation in comprehensive financial planning services and executive health physicals. On occasion, the Company may also provide for spousal travel and accommodations when accompanying the executive on out-of-town trips. The Company withholds income taxes on the amounts as required.

Committee Consideration of Compensation Program Risk

At the request of the Committee, an analysis of the risks associated with the Company's compensation programs, including those for executive officers, was performed by management, including the participation of the Vice President-Risk Management and Controller. The conclusions of this analysis, with which the Committee concurred, were that the risks associated with the Company's compensation programs are not likely to have a material adverse effect on the Company and instead encourage overall balanced performance that supports sustainable shareholder value. Among the items the Committee considered were:

- The annual incentive plans for all employees (including officers) contain a diverse array of measures that focus on the fundamental aspects of our business.
- The performance measures for all incentive compensation programs are directly tied to the Company's annual and long-term financial results and/or business plans.
- The maximum amount payable to officer employees under our AIP ranges from approximately 40 percent at the lowest level to 200 percent of base salary for the NEOs.
- The officer compensation program design provides a balanced mix of cash and equity, annual and long-term incentives and diverse performance objectives.
- The Company currently does not grant stock options.
- The Company (for non-officers) and the Committee (for officers) have downward discretion over both cash and equity incentive program payouts.
- The Company has "clawback" provisions for its officer annual incentive compensation and LTIP performance share awards.
- Officers are subject to share ownership and retention guidelines.
- The Board oversees the Company's enterprise risk management and mitigation programs, including the possible impacts of variables on the earnings and credit position of the Company, which are important aspects of the Company's incentive compensation plans.
- The officers' AIP and LTIP performance share grants have a "stretch" performance level to flatten the steepness of the performance payout curve and further reinforce the appropriate behavioral incentives.
- Under the LTIP, any payout is capped at target or 100 percent, if TSR performance is negative even if a greater award is prescribed by the performance share objectives.

Tax and Accounting Implications

For the year ended December 31, 2017, Section 162(m) of the Internal Revenue Code generally disallowed deduction of compensation in excess of $1,000,000 paid to certain covered officers including the principal executive officer and our next three highest paid executive officers, other than our principal financial officer. For 2017, the Section 162(m) limitation did not apply to performance-based compensation, provided certain conditions were met. Although the Committee considers tax deductibility in making compensation decisions, the Committee does not believe that compensation decisions should be determined solely by how much compensation is deductible for federal income tax purposes. As a result, the Committee retains the discretion to authorize payments that may not be deductible if it believes that they are in the best interests of the Company and its shareholders.

For 2018 and subsequent years, covered officers include the principal executive officer, principal financial officer, and next three highest paid NEOs. Compensation paid in 2018 and later years will generally be subject to the deduction limits of Section 162(m), without an exception for performance-based compensation. This includes annual and long-term incentive awards paid and equity awards granted in 2018 and later years.

COMPENSATION COMMITTEE REPORT

The Compensation and Development Committee of the Board reviewed and discussed with management the Compensation Discussion and Analysis contained in this Item 11 and, based on these reviews and discussions, recommended to the Board that the Compensation Discussion and Analysis be included in this Amendment to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2017.

Compensation and Development Committee

John J. Sherman, Chair
Randall C. Ferguson, Jr.
Gary D. Forsee
Scott D. Grimes
Sandra J. Price

EXECUTIVE COMPENSATION

The following table shows all compensation paid to, awarded to and earned by our NEOs for services rendered in all capacities to Great Plains Energy, our two public utility subsidiaries, KCP&L and GMO, and all other Great Plains Energy subsidiaries. Unless otherwise indicated, the listed individuals held the same position at Great Plains Energy, KCP&L and GMO.

SUMMARY COMPENSATION TABLE

Name and Principal Position	Year	Salary ($)	Bonus ($)	Stock Awards(1) ($)	Non-Equity Incentive Plan Compensation(2) ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings(3) ($)	All Other Compensation(4) ($)	Total ($)
Mr. Bassham Chairman, President and Chief Executive Officer	2017	880,000	—	2,514,510	1,082,400	568,773	141,637	5,187,320
	2016	800,000	—	2,283,294	1,144,000	352,896	92,192	4,672,382
	2015	685,000	250,000	1,724,694	95,900	204,840	93,024	3,053,458
Mr. Bryant Senior Vice President - Finance and Strategy and Chief Financial Officer	2017	462,000	—	733,424	646,800	243,355	34,910	2,120,489
	2016	402,000	—	509,985	344,916	125,999	40,152	1,423,052
	2015	316,957 (5)	78,000	641,599	21,411	32,510	48,914	1,139,391
Ms. Humphrey Senior Vice President- Corporate Services and General Counsel	2017	413,000	—	524,521	495,600	187,725	63,191	1,684,037
	2016	393,000	—	498,561	337,194	108,233	55,022	1,392,010
	2015	357,000	75,000	399,514	24,990	40,432	41,741	938,677
Ms. Wright Vice President- Corporate Planning, Investor Relations and Treasurer	2017	311,000	—	246,901	248,800	212,798	28,111	1,047,610
	2016	296,000	—	234,700	169,312	136,248	47,317	883,577
Mr. Caisley Vice President- Marketing and Public Affairs	2017	300,000	—	238,152	300,000	109,514	28,180	975,846
Mr. Heidtbrink Former Executive Vice President and Chief Operating Officer- KCP&L and GMO	2017	570,000	—	1,055,650 (6)	—	191,296	325,861 (7)	2,142,807
	2016	543,000	—	1,004,512	543,543	242,752	53,553	2,387,360
	2015	503,000	226,000	820,864	49,294	107,944	54,816	1,761,918

(1) The amounts shown in this column are the aggregate grant date fair values of restricted stock and performance shares granted under our LTIP during each year, computed in accordance with the Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") Topic 718. See note 10 to the consolidated financial statements included in the Original Filing for a discussion of the relevant assumptions used in calculating these amounts. The amounts shown exclude the effect of estimated forfeitures, as required by SEC rules.

The amounts shown in this column reflect the value at the grant date of performance share awards based upon achieving the target level of performance, which was considered the probable outcome as of the grant date. The payout of performance share awards can range from 0 percent to 200 percent of the target amount, depending upon performance. The following table shows the aggregate grant date fair value of performance shares for each year for both target and maximum levels of performance.

Name	Grant date fair value of 2015 performance share awards ($)		Grant date fair value of 2016 performance share awards ($)		Grant date fair value of 2017 performance share awards ($)	
	Target	Maximum	Target	Maximum	Target	Maximum
Mr. Bassham	1,265,628	2,531,256	1,746,804	3,493,608	1,926,866	3,853,732
Mr. Bryant	251,801	503,602	390,144	780,288	562,024	1,124,048
Ms. Humphrey	293,171	586,342	381,412	762,824	401,941	803,882
Ms. Wright	147,319	294,638	179,540	359,080	189,186	378,372
Mr. Caisley	142,700	285,400	173,477	346,954	182,496	364,992
Mr. Heidtbrink	602,366	1,204,732	768,477	1,536,954	808,946	1,617,892

For further information on these awards, see the Grants of Plan-Based Awards table on page 28 and Outstanding Equity Awards at Fiscal Year-End table on page 29.

(2) The amounts shown in this column are cash awards earned under our AIP.

(3) The amounts shown in this column include the aggregate of the increase in actuarial values of each of the officer's benefits under our pension plan, SERP and the above-market earnings on compensation that is deferred on a non-tax qualified basis. Following are the amounts of these items attributable to each NEO for 2017:

	Change in Pension Value ($)	Change in SERP ($)	Above-Market Earnings on Deferred Compensation ($)
Mr. Bassham	107,234	408,194	53,345
Mr. Bryant	94,989	148,366	—
Ms. Humphrey	87,764	86,184	13,777
Ms. Wright	133,942	76,319	2,537
Mr. Caisley	77,496	32,018	—
Mr. Heidtbrink	191,296	—	—

(4) These amounts include the value of perquisites and personal benefits that are not available on a non-discriminatory basis to all employees, as well as other compensation items discussed in this footnote. The amounts in this column consist of, as applicable for each NEO: (A) employer match of employee contributions to our 401(k) plan; (B) employer match of compensation deferred under our DCP (see an explanation of this item beginning on page 35); (C) executive financial planning services; (D) parking; (E) executive health physicals and (F) separation bonus paid upon retirement. All amounts shown are in dollars.

Name	(A)	(B)	(C)	(D)	(E)	(F)	Total
Mr. Bassham	16,200	105,240	17,127	1,260	1,810	—	141,637
Mr. Bryant	16,200	—	17,450	1,260	—	—	34,910
Ms. Humphrey	16,200	28,812	14,575	1,260	2,344	—	63,191
Ms. Wright	16,200	—	10,651	1,260	—	—	28,111
Mr. Caisley	16,200	—	10,720	1,260	—	—	28,180
Mr. Heidtbrink	5,498	—	17,011	525	—	302,827	325,861

(5) On September 2, 2015, Mr. Bryant became our Senior Vice President-Finance and Strategy and Chief Financial Officer. Effective with his appointment, Mr. Bryant's salary was increased to $390,000 on a prorated basis.

(6) Mr. Heidtbrink retired from the Company effective May 1, 2017. Pursuant to the terms of a retirement agreement with the Company, Mr. Heidtbrink forfeited his 2017 annual incentive award and all his restricted stock and performance share awards granted in 2017. The original grant amounts are reflected above. The terms of the agreement are more fully described under Other Agreements on page 23.

(7) In addition, Mr. Heidtbrink's retirement agreement provided for a bonus of $302,827; the bonus was paid at his retirement that was effective May 1, 2017.

The following table provides additional information with respect to awards under both the non-equity and equity incentive plans. We have omitted from the table the columns titled “All Other Option Awards: Number of Securities Underlying Options” and “Exercise or Base Price of Option Awards,” because no options were granted in 2017.

GRANTS OF PLAN-BASED AWARDS

		Estimated Possible Payouts Under Non-Equity Incentive Plan Awards			Estimated Future Payouts Under Equity Incentive Plan Awards			All Other Stock Awards: Number of Shares of Stock or Units (#)	Grant Date Fair Value of Stock ($)
Name	**Grant Date**	**Threshold ($)**	**Target ($)**	**Maximum ($)**	**Threshold (#)**	**Target (#)**	**Maximum (#)**		
Mr. Bassham	February 14, 2017(1)	440,000	880,000	1,760,000					
	March 1, 2017(2)				30,820	61,640	123,280		1,926,866
	March 1, 2017(3)							20,547	587,644
Mr. Bryant	February 14, 2017(1)	161,700	323,400	646,800					
	March 1, 2017(2)				8,990	17,979	35,958		562,024
	March 1, 2017(3)							5,993	171,400
Ms. Humphrey	February 14, 2017(1)	123,900	247,800	495,600					
	March 1, 2017(2)				6,429	12,858	25,716		401,941
	March 1, 2017(3)							4,286	122,580
Ms. Wright	February 14, 2017(1)	62,200	124,400	248,800					
	March 1, 2017(2)				3,026	6,052	12,104		189,186
	March 1, 2017(3)							2,018	57,715
Mr. Caisley	February 14, 2017(1)	75,000	150,000	300,000					
	March 1, 2017(2)				2,919	5,838	11,676		182,496
	March 1, 2017(3)							1,946	55,656
Mr. Heidtbrink	February 14, 2017(1)(4)	66,500	133,000	266,000					
	March 1, 2017(2)(4)				12,939	25,878	51,756		808,946
	March 1, 2017(3)(4)							8,626	246,704

(1) Reflects the payments under our 2017 AIP, measured at the grant date. The actual amounts earned in 2017 are reported as Non-Equity Incentive Plan Compensation in the Summary Compensation Table on page 26.

(2) Consists of performance share awards under our LTIP for the 2017-2019 performance period that vest on March 2, 2020. Performance shares are payable in common stock, cash, or a combination of common stock and cash after the end of the performance period. Actual payments depend on the three-year TSR compared to the EEI Index. The awards can range from 0 percent to 200 percent of the target amount. Dividend equivalents will be paid in cash after the end of the period on the number of shares earned. The grant date fair value, calculated in accordance with FASB ASC Topic 718 (excluding the effect of estimated forfeitures), is $31.26 per share and reflects the target number of shares.

(3) Consists of time-based restricted stock awards under the LTIP that vest on March 2, 2020. The grant date fair value, calculated in accordance with FASB ASC Topic 718 (excluding the effect of estimated forfeitures), is $28.60 per share.

(4) Mr. Heidtbrink retired from the Company effective May 1, 2017. Pursuant to the terms of a retirement agreement with the Company, Mr. Heidtbrink forfeited his 2017 annual incentive award and his restricted stock and performance share awards granted in 2017. The original amounts are reflected above. The terms of the agreement are more fully described under Other Agreements on page 23.

OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END

The following table provides information regarding the outstanding equity awards held by each of the NEOs as of December 31, 2017. There are no outstanding options.

	Stock Awards			
Name(1)	**Number of Shares of Stock That Have Not Vested (#)(2)(3)**	**Market Value of Shares of Stock That Have Not Vested ($)(3)(4)**	**Equity Incentive Plan Awards: Number of Unearned Shares That Have Not Vested (#)(5)**	**Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares That Have Not Vested ($)(4)(5)**
Mr. Bassham	112,887	3,639,477	117,253	3,780,237
Mr. Bryant	29,727	958,398	30,400	980,096
Ms. Humphrey	25,400	818,896	25,001	806,032
Ms. Wright	12,487	402,581	11,768	379,400
Mr. Caisley	12,081	389,491	11,361	366,279

(1) On May 1, 2017, the Company entered into a retirement agreement with Mr. Heidtbrink in connection with his retirement from the Company. The agreement provided for the forfeiture of restricted stock and performance share awards granted in 2017 to Mr. Heidtbrink, and the vesting of all restricted stock grants and the vesting of prorated performance share awards granted prior to 2017. The original grant amounts are reflected above. The terms of the agreement are more fully described under Other Agreements on page 23.

(2) Includes reinvested dividends on restricted stock that carry the same restrictions.

(3) Reflects the time-based restricted stock grants that were not vested as of December 31, 2017. The following table provides the grant and vesting dates and number of unvested shares (including reinvested dividend shares) for each of the outstanding grants as of December 31, 2017. Also included are the 2015-2017 performance share awards, which, as of December 31, 2017, were earned, but had not yet vested.

Name	Grant Date	Vesting Date	Number of Shares That Have Not Vested
Mr. Bassham	March 2, 2015[(a)]	March 2, 2018	52,603
	March 2, 2015	March 2, 2018	19,411
	March 1, 2016	March 1, 2019	19,772
	March 1, 2017	March 2, 2020	21,101
Mr. Bryant	March 2, 2015[(a)]	March 2, 2018	5,995
	March 2, 2015	March 2, 2018	2,213
	September 2, 2015[(a)]	March 2, 2018	4,789
	September 2, 2015	March 2, 2018	1,734
	September 2, 2015	March 2, 2018	4,424
	March 1, 2016	March 1, 2019	4,417
	March 1, 2017	March 2, 2020	6,155
Ms. Humphrey	March 2, 2015[(a)]	March 2, 2018	12,185
	March 2, 2015	March 2, 2018	4,496
	March 1, 2016	March 1, 2019	4,317
	March 1, 2017	March 2, 2020	4,402
Ms. Wright	March 2, 2015[(a)]	March 2, 2018	6,123
	March 2, 2015	March 2, 2018	2,259
	March 1, 2016	March 1, 2019	2,033
	March 1, 2017	March 2, 2020	2,072
Mr. Caisley	March 2, 2015[(a)]	March 2, 2018	5,931
	March 2, 2015	March 2, 2018	2,188
	March 1, 2016	March 1, 2019	1,964
	March 1, 2017	March 2, 2020	1,998

(a) Represents the 2015-2017 performance share awards, which as of December 31, 2017, were earned but not yet vested.

(b) On May 1, 2017, the Company entered into a retirement agreement with Mr. Heidtbrink in connection with his retirement from the Company. The agreement provided for the forfeiture of restricted stock and performance share awards granted in 2017 to Mr. Heidtbrink, and the vesting of all other restricted stock grants and the vesting of prorated performance share awards granted prior to 2017. The original grant amounts are reflected above. The terms of the agreement are more fully described under Other Agreements on page 23.

(4) The value of the shares is calculated by multiplying the number of shares by the closing market price ($32.24) as of December 29, 2017.

(5) Reflects the performance share awards, at target, that were outstanding as of December 31, 2017. The value of the shares is calculated by multiplying the number of shares by the closing market price ($32.24) on December 29, 2017. The following table provides, by performance period for each NEO, the target number of performance shares for each of the outstanding grants as of December 31, 2017.

Name[a]	Performance Period	Number of Shares[b]
Mr. Bassham	2016-2018	55,613
	2017-2019	61,640
Mr. Bryant	2016-2018	12,421
	2017-2019	17,979
Ms. Humphrey	2016-2018	12,143
	2017-2019	12,858
Ms. Wright	2016-2018	5,716
	2017-2019	6,052
Mr. Caisley	2016-2018	5,523
	2017-2019	5,838

(a) On May 1, 2017, the Company entered into a retirement agreement with Mr. Heidtbrink in connection with his retirement from the Company. The agreement provided for the forfeiture of performance share awards granted in 2017 to Mr. Heidtbrink, and the vesting of prorated performance share awards granted prior to 2017. The original grant amounts are reflected above. The terms of the agreement are more fully described under Other Agreements on page 23.

(b) The number of shares actually earned for each applicable performance period is determined shortly following the end of the performance period based on achievement of the performance objectives.

OPTION EXERCISES AND STOCK VESTED

The following table provides information regarding the vesting of stock awards held by each of the NEOs during 2017. We have omitted the "Option Awards" columns from the following table, because our NEOs do not have options.

Name	Number of Shares Acquired on Vesting (#)[1]	Value Realized on Vesting ($)[1]
Mr. Bassham	79,140	2,457,621
Mr. Bryant	15,139	465,350
Ms. Humphrey	19,077	591,312
Ms. Wright	8,230	257,526
Mr. Caisley	8,052	251,951
Mr. Heidtbrink	88,657	2,662,311

(1) Awards of time-based restricted stock, plus reinvested dividends, vested on March 3, 2017 and September 5, 2017. Shares earned on reinvested dividends on time-based restricted stock that had previously vested, vested on March 20, 2017 and September 20, 2017. Common stock was paid on March 3, 2017, on performance shares earned for the 2014-2016 performance period. The following table provides detail for each of these vesting and payment events.

	Vesting or Payment Date	Restricted Stock Vesting	Reinvested Dividends Vesting	Stock Paid on Performance Shares	Value on Vesting or Payment Date[a] ($)
Mr. Bassham	March 3, 2017	17,204	1,837		554,284
	March 3, 2017			51,610	1,656,939
	March 15, 2017	7,998	230		238,941
	March 20, 2017		261		7,457
Mr. Bryant	March 3, 2017	1,982	212		63,867
	March 3, 2017			5,944	190,832
	March 15, 2017	2,496	72		74,575
	March 20, 2017		46		1,314
	September 5, 2017	4,074	274		133,571
	September 20, 2017		39		1,191
Ms. Humphrey	March 3, 2017	4,028	430		129,772
	March 3, 2017			12,083	387,925
	March 15, 2017	2,400	69		71,700
	March 20, 2017		67		1,915
Ms. Wright	March 3, 2017	2,000	212		64,392
	March 3, 2017			5,997	192,534
	March 20, 2017		21		600
Mr. Caisley	March 3, 2017	1,956	209		63,023
	March 3, 2017			5,866	188,328
	March 20, 2017		21		600
Mr. Heidtbrink[b]	March 3, 2017	8,104	865		261,088
	March 3, 2017			24,310	780,472
	March 15, 2017	7,230	208		216,000
	March 20, 2017		157		4,485
	May 9, 2017	16,502	965		489,950
	May 9, 2017			30,316	910,316

(a) Value is based on the closing stock price on the day of vesting or payment. At the time of payment, dividend equivalents were paid in cash to Mr. Bassham ($154,572), Mr. Bryant ($17,802), Ms. Humphrey ($36,189), Ms. Wright ($17,961), Mr. Caisley ($17,569), and Mr. Heidtbrink ($132,760). The following table provides the applicable stock price.

Vesting or Payment Date	Stock Price ($)
March 3, 2017	29.11
March 15, 2017	29.04
March 20, 2017	28.57
May 9, 2017	28.05
September 5, 2017	30.72
September 20, 2017	30.55

(b) On May 1, 2017, the Company entered into a retirement agreement with Mr. Heidtbrink in connection with his retirement from the Company. The agreement provided for the forfeiture of restricted stock and performance share grants made in 2017 to Mr. Heidtbrink, the vesting of all other restricted stock grants and vesting of prorated performance share awards granted prior to 2017. The terms of the agreement are more fully described under Other Agreements on page 23.

PENSION BENEFITS

In the following table, the present value of the accumulated benefits under the Pension Plan and SERP with respect to each of the NEOs is based on the following assumptions: retirement at the later of the age of such officer as of December 31, 2017, or age 62 (for Old Retirement Plan participants, the earlier of age 62 or when the sum of age and years of service equal 85); full vesting of accumulated benefits; a discount rate of 3.70 percent for the Pension Plan and 3.80 percent for the SERP; and use of the Pension Protection Act mortality and lump sum interest rate tables.

Name	Plan Name	Number of Years Credited Service (#)	Present Value of Accumulated Benefit ($)	Payments During Last Fiscal Year ($)
Mr. Bassham	Management Pension Plan	12.5	533,299	—
	Supplemental Executive Retirement Plan	12.0	1,355,327	—
Mr. Bryant	Management Pension Plan	14.0	357,198	—
	Supplemental Executive Retirement Plan	14.0	300,656	—
Ms. Humphrey	Management Pension Plan	10.9	337,721	—
	Supplemental Executive Retirement Plan	10.4	258,894	—
Ms. Wright	Management Pension Plan	16.2	654,996	—
	Supplemental Executive Retirement Plan	16.2	265,527	—
Mr. Caisley	Management Pension Plan	10.2	277,171	—
	Supplemental Executive Retirement Plan	10.2	100,833	—
Mr. Heidtbrink[(1)]	Management Pension Plan	9.0	1,182,489	—
	Supplemental Executive Retirement Plan	9.0	—	556,208

(1) Mr. Heidtbrink was a GMO employee prior to its acquisition by Great Plains Energy in 2008. Mr. Heidtbrink ceased accruing benefits under the GMO pension plan as of the acquisition date, and started accruing benefits under the Pension Plan and SERP. The years of credited service shown for him reflect service under these latter plans; however, the present value of accumulated benefits shown for the management pension plan reflects both his frozen GMO pension plan benefit and his Pension Plan benefit. Mr. Heidtbrink retired from the Company effective May 1, 2017, and is no longer eligible for benefits under the SERP.

Our NEOs participate in the Pension Plan and the SERP. In 2007, our non-union employees were given a one-time election to remain under the existing terms of the Pension Plan (the “Old Retirement Plan”), or to elect a new retirement program (the “Current Retirement Plan”) that included a slightly reduced benefit accrual formula under the Pension Plan (as well as a correspondingly reduced benefit accrual formula under the SERP for employees who participate in the SERP). Messrs. Bassham, Bryant and Caisley and Mses. Humphrey and Wright elected the Current Retirement Plan. Mr. Heidtbrink joined the Company subsequent to 2007, and was automatically enrolled in the Current Retirement Plan. We note the differences between the Old Retirement Plan and the Current Retirement Plan below.

Pension Plan

The Pension Plan is a funded, tax-qualified, noncontributory defined benefit pension plan for non-union employees hired or rehired on or before December 31, 2013. Benefits under the Pension Plan are based on the employee’s years of service and the average annual base salary over a specified period. Employees who elected to remain in the Old Retirement Plan and retire after they reach 65, or whose age and years of service at or after age 52 add up to 85 (the “Rule of 85”), are entitled under the Pension Plan to a total monthly annuity for the rest of their life (a “single life” annuity) equal to 50 percent of their average base monthly salary for the period of 36 consecutive months in which their earnings were highest. This reflects an accrual rate of 1.67 percent per year, capped at 30 years of service. The 50 percent single life annuity will be proportionately reduced if years of credited service are less than 30. Employees may also elect to retire and receive an unreduced benefit at age 62 with at least 5 years of credited service, in which case the benefit is based on their average base monthly salary for the period of 48 consecutive months in which their earnings were highest. Employees may also elect early retirement benefits if they retire between the ages of 55 and 62; in such a case the benefit is reduced by three percent for each year that commencement precedes age 62. Employees may elect other annuity options, such as joint and survivor annuities or annuities with payments guaranteed for a period of time. The present value of each annuity option is the same; however, the monthly amounts payable under these options are less than the amount payable under the single life annuity option. Employees also may elect to receive their retirement benefits in a lump sum equal to the actuarial equivalent of a single life pension under the Pension Plan.

Employees, such as Messrs. Bassham, Bryant and Caisley and Mses. Humphrey and Wright, who elected the Current Retirement Plan, retained the benefit they accrued as of December 31, 2007, under the old formula with the old early retirement reductions. Mr. Heidtbrink has benefits only under the Current Retirement Plan. Participants in the Current Retirement Plan earn a benefit equal to 1.25 percent of their final average base earnings (averaged over 48 consecutive months), multiplied by the years of credited service earned after 2007. There is no cap on the years of credited service that can be earned. Employees under the Current Retirement Plan may begin receiving their retirement benefit at age 55, but with a five percent per year reduction for each year before age 62. There is no Rule of 85 for post-2007 accrued benefits; however, participants may receive post-2007 accrued benefits (subject to the five percent per year reduction if they retire at or after age 55 and before age 62) when they start receiving pre-2008 accrued benefits. Participants in the Current Retirement Plan may receive only their pre-2008 accrued benefits in a lump sum; post-2007 benefits must be taken in the form of one of the annuities described in the preceding paragraph.

SERP

The SERP is unfunded and provides out of general assets an amount substantially equal to the difference between the amount that would have been payable under the Pension Plan in the absence of tax laws limiting pension benefits and earnings that may be considered in calculating pension benefits, and the amount actually payable under the Pension Plan. For participants under the Old Retirement Plan, it adds an additional one-third percent of highest average annual base salary for each year of credited service when the executive was eligible for supplemental benefits, up to a maximum of 30 years, and also makes up the difference (if any) between using a 36-month earnings averaging period and the averaging period used for the participant's benefits under the Pension Plan. Participants under the Current Retirement Plan receive this same benefit; however, there is no cap on the years of credited service for benefits accrued after 2007. Participants may elect the timing of the receipt of their benefits, as well as the form of their benefits (a lump sum payment or a variety of annuity options, all of which have the same present value). All of our NEOs have elected to receive their benefits in a lump sum upon separation from service. For participants, such as our NEOs, who are "specified employees" under Internal Revenue Code Section 409A and who elect payment on separation of service, payment of benefits accrued prior to 2005 will be made, or commence, when they separate from service; payment of benefits accrued after 2004 will be made, or commence, on the first business day of the seventh calendar month following their separation from service.

NONQUALIFIED DEFERRED COMPENSATION

Name	Executive Contribution in Last FY(1) ($)	Registrant Contributions in Last FY(2) ($)	Aggregate Earnings in Last FY(3) ($)	Aggregate withdrawals/ distributions ($)	Aggregate Balance at Last FYE(4) ($)
Mr. Bassham	150,000	105,240	82,047	—	1,276,632
Mr. Bryant	—	—	—	—	—
Ms. Humphrey	109,032	28,812	21,198	(70,913)	403,967
Mr. Wright	6,000	—	3,901	—	59,380
Mr. Caisley	—	—	—	—	—
Mr. Heidtbrink	—	—	—	—	—

(1) The entire amount shown for each NEO is included in the 2017 salary and non-equity incentive plan compensation information shown for such person in the Summary Compensation Table on page 26. To provide consistency with the Summary Compensation Table, this table shows deferrals of compensation earned in 2017 (whether paid in 2017 or 2018). The amounts of 2017 salary deferred are: Mr. Bassham, $150,000; Ms. Humphrey, $49,560 and Ms. Wright, $3,000. The amounts of 2017 deferred non-equity incentive award compensation are: Ms. Humphrey $59,472; and Ms. Wright, $3,000.

(2) The entire amount shown in this column for each NEO is included in the amount shown for each NEO in the "All Other Compensation" column in the Summary Compensation Table.

(3) Only the above-market earnings are reported in the Summary Compensation Table. The above-market earnings were: Mr. Bassham, $53,345; Ms. Humphrey, $13,777; and Ms. Wright, $2,537.

(4) The following amounts reported in this column were reported as compensation to the NEOs in the Summary Compensation Tables for previous years: Mr. Bassham, $174,165 (2016) and $113,595 (2015); Ms. Humphrey, $107,079 (2016) and $66,310 (2015); and Ms. Wright, $8,099 (2016).

Our DCP is a nonqualified and unfunded plan. It allows officers, including our NEOs, to defer the receipt of compensation. The DCP provides for a matching contribution in an amount equal to 50 percent of the first 6 percent of the base salary deferred by Old Retirement Plan participants, reduced by the amount of the matching contribution made for the year to the participant's account under our 401(k) Plan, as described in the section titled "Compensation Discussion and Analysis" starting on page 5. For Current Retirement Plan participants, the DCP provides for a matching contribution in an amount equal to 100 percent of the first 6 percent of the base salary, bonus and incentive pay deferred, reduced by the amount of the matching contribution made for the year to the participant's account under the 401(k) Plan. An earnings rate is applied to the deferral amounts. This rate is determined annually by the Committee and is based on the Company's weighted average cost of capital. The rate was set at 7.5 percent for 2017. Interest is compounded monthly on deferred amounts. Participants may elect prior to rendering services for which the compensation relates when deferred amounts are to be paid to them: either at a specified date or upon separation from service. For participants, such as our NEOs, who are "specified employees" under Internal Revenue Code Section 409A and who elect payment on separation of service, payment will be made, or commence, on the first business day of the seventh calendar month following their separation from service.

POTENTIAL PAYMENTS UPON TERMINATION OR CHANGE IN CONTROL

Our NEOs are eligible to receive payments in connection with termination of their employment, as explained in this section.

Payments under Change in Control Severance Agreements

We have Change in Control Severance Agreements ("Change in Control Agreements") with each of our NEOs, specifying the benefits payable in the event their employment is terminated within two years of a "Change in Control" or within a "protected period." Generally, a "Change in Control" occurs if:

- any person (as defined by SEC regulations) becomes the beneficial owner of at least 35 percent of our outstanding shares of common stock or of the combined voting power of our outstanding securities;
- a change occurs in the majority of our Board;
- a merger, consolidation, reorganization or similar transaction is consummated (unless our shareholders continue to hold at least 60 percent of the voting power of the surviving entity); or
- a complete liquidation, complete dissolution or an agreement for the sale or disposition of substantially all of our assets occurs or is approved by our shareholders (unless our shareholders continue to hold at least 60 percent of the voting power after such disposition or sale).

A "protected period" starts when:

- we enter into an agreement that, if consummated, would result in a Change in Control;
- we, or another person, publicly announces an intention to take or to consider taking actions which, if consummated, would constitute a Change in Control;
- any person (as defined by SEC regulations) becomes the beneficial owner of 10 percent or more of our outstanding voting securities; or
- our Board, or our shareholders, adopt a resolution approving any of the foregoing matters or approving a Change in Control.

The protected period ends when the Change in Control transaction is consummated, abandoned or terminated.

The Company believes that the occurrence, or potential occurrence, of a change in control transaction will create uncertainty regarding the continued employment of our executive officers. This uncertainty results from the fact that many change in control transactions result in significant organizational changes, particularly at the senior executive level. We believe these change in control arrangements effectively create incentives for our executive team to build shareholder value and to obtain the highest value possible should we be acquired in the future, despite the risk of losing employment and potentially not having the opportunity to otherwise vest in equity awards which are a significant component of each executive's compensation. These agreements are designed to encourage our NEOs to remain employed with the Company during an important time when their prospects for continued employment following the transaction could be uncertain. Because we believe that a termination by the executive for good reason may be conceptually the same as a termination by the Company without cause, and because we believe that in the context of a change in control, potential acquirers would otherwise have an incentive to constructively terminate the executive's employment to avoid paying severance, we believe it is appropriate to provide severance benefits in these circumstances.

Our change in control arrangements are "double trigger," meaning that acceleration of vesting is not awarded upon a change in control, unless the NEO's employment is terminated by the Company involuntarily, other than for "Cause" or by such NEO for "Good Reason" (each of which are generally explained below) within two years of a Change in Control or protected period. We believe this structure provides a balance between the incentives and the executive hiring and retention considerations described above, without providing these benefits to executives who continue to enjoy employment with an acquiring company in the event of a change in control transaction. We also believe this structure is more attractive to potential acquiring companies, who may place significant value on retaining members of our executive team and who may perceive this goal to be undermined if executives receive significant acceleration payments in connection with such a transaction and are no longer required to continue employment to earn the remainder of their equity awards.

The benefits under the Change in Control Agreements depend on the circumstances of termination. The benefits are greater if the employee is not terminated for "Cause," or if the employee terminates employment for "Good Reason." "Cause" includes:

- a material misappropriation of any funds, confidential information or property;
- the conviction of, or the entering of, a guilty plea or plea of no contest with respect to a felony (or equivalent);
- willful damage, willful misrepresentation, willful dishonesty or other willful conduct that can reasonably be expected to have a material adverse effect on the Company; or
- gross negligence or willful misconduct in performance of the employee's duties (after written notice and a reasonable period to remedy the occurrence).

An employee has "Good Reason" to terminate employment if:

- there is any material and adverse reduction or diminution in position, authority, duties or responsibilities below the level provided at any time during the 90-day period before the "protected period";
- there is any reduction in annual base salary after the start of the "protected period" (unless such reduction is in connection with a company-wide reduction);
- there is any reduction in benefits below the level provided at any time during the 90-day period prior to the "protected period";
- the employee is required to be based at any office or location that is more than 70 miles from where the employee was based immediately before the start of the "protected period"; or
- the Company fails to require any successor to all or substantially all of the Company's business or assets to assume expressly and agree to perform under the Change in Control Agreements.

Our Change in Control Agreements also have covenants prohibiting the disclosure of confidential information and preventing the employee from participating or engaging in any business that, during the employee's employment, and six months after, is in direct competition with the business of the Company or its affiliates within the United States (without prior written consent which, in the case of termination, will not be unreasonably withheld).

Change in Control with Termination of Employment

The following table sets forth our payment obligations under the Change in Control Agreements, existing awards of restricted stock and performance shares, SERP and DCP under the circumstances specified upon a termination of employment for our NEOs. The amounts shown in the table are based on the following assumptions: (i) that the termination took place on December 31, 2017 and (ii) that the NEO was paid for all salary earned through the date of termination. Please refer to the "Pension Benefits" section for information regarding benefits available under the Pension Plan.

Benefit	Mr. Bassham ($)	Mr. Bryant ($)	Ms. Humphrey ($)	Ms. Wright ($)	Mr. Caisley ($)
Two Times Salary(1)	1,760,000	924,000	826,000	622,000	600,000
Two Times Bonus(2)	1,148,000	260,424	340,154	212,934	203,440
Annual Bonus(3)	1,082,400	646,800	495,600	248,800	300,000
DCP payment(4)	1,324,191	—	258,280	61,547	—
SERP payment(5)	1,360,632	194,089	177,476	233,204	65,912
Additional Retirement Benefits(6)	622,222	439,256	390,426	249,687	310,399
Performance Share Awards Vesting(7)	5,830,450	1,408,487	1,277,784	615,172	594,601
Restricted Stock Vesting(8)	1,943,544	610,714	426,068	205,195	198,292
Health and Welfare(9)	59,007	57,874	43,628	49,200	49,171
Accrued Vacation Payout	67,692	35,538	31,769	23,923	23,077
Tax Gross-Up(10)	3,399,908	1,338,341	1,091,287	—	660,527
Total	18,598,046	5,915,523	5,358,472	2,521,662	3,005,419

(1) The NEOs receive two times their highest annual base salary, during the twelve-month period prior to the date of termination.

(2) The NEOs receive two times their average annualized annual incentive compensation awards.

(3) The Change in Control Agreements provide for a bonus at least equal to the average annualized incentive awards paid to the NEO during the last five fiscal years of the Company (or the number of years the NEO worked for the Company) immediately before the fiscal year in which the Change in Control occurs, prorated for the number of days employed in the year in which the Change in Control occurred. As the NEOs would have been eligible to receive the full amount of the 2017 AIP payments, which the annual bonus payment equals the 2017 annual incentive plan payments.

(4) Because the NEOs are "specified employees" under Internal Revenue Code Section 409A, payments triggered by a separation from service are delayed to the first business day of the seventh month after the month in which separation from service occurs. Thus, the amounts shown for them reflect their DCP account balances as of December 31, 2017, plus interest on the balances to the July 1, 2018 payment date for those portions to be paid as of the date of separation from service. Messrs. Bryant and Caisley had no deferred compensation as of December 31, 2017.

(5) All of our NEOs included in this table have elected to have their SERP benefits paid in a lump sum upon separation from service. The amounts shown on this line reflect the benefits payable under the SERP as of a July 1, 2018 payment date, reflecting the required Section 409A delay; the additional benefit arising from additional years of service credited upon a Change in Control is provided on the next line.

(6) The amounts reflect the present value of the benefit arising from additional years of service credited upon a Change in Control. The NEOs are credited for two additional years of service. These benefits are paid through our SERP.

(7) In the event of a "change in control" (which is consistent with the definition of a Change in Control in the Change in Control Agreements) and termination of employment without Cause or for Good Reason, our LTIP provides that all performance share grants are deemed to have been fully earned. The amounts shown for each person reflect the aggregate target number of performance shares, valued at the $32.24 closing price of our stock on December 29, 2017, plus accrued cash dividends.

(8) In the event of a Change in Control and termination of employment without Cause or for Good Reason, our LTIP provides that all restrictions on restricted stock grants are removed. The amounts shown for each person reflect the aggregate number of restricted stock grants outstanding as of December 31, 2017, plus reinvested dividends carrying the same restrictions, valued at the $32.24 closing price of our stock on December 29, 2017.

(9) The amounts include medical, accident, disability and life insurance for two years following termination and are estimated based on our current premiums for medical coverage and indicative premiums for private insurance coverage for the individuals, as well as $16,920 payable for financial services for one year for Messrs. Bassham, Bryant and Ms. Humphrey and $10,745 for Ms.Wright and Mr. Caisley.

(10) Because these officers' Change in Control Agreements were entered into before August 2013, they provide for an additional payment to cover excise taxes imposed by Section 4999 of the Internal Revenue Code ("Section 280G gross-up payments"). We have calculated these payments based on the estimated payments discussed above. In calculating these payments, we did not make any reductions for the value of reasonable compensation for pre-Change in Control period and post-Change in Control period service, such as the value attributed to non-compete provisions. In the event that payments are due under Change in Control Agreements, we would perform evaluations to determine the reductions attributable to these services.

Retirement

Upon retirement, each NEO would receive a lump sum cash payment of all earned and unpaid salary, accrued but unused vacation, and the SERP and DCP benefits discussed above, among other benefits. Please refer to the "Pension Benefits" section starting on page 33 for information regarding benefits available under the Pension Plan.

Performance share and restricted stock awards are forfeited upon retirement, unless the Board took other action in its sole discretion. Retirees are eligible for a prorated portion of AIP awards. There would have been no proration for a December 31, 2017 retirement, and the amounts of the 2017 awards are set out in the column titled "Non-Equity Incentive Plan Compensation" in the Summary Compensation Table on page 26.

Death or Disability

In the event of death or disability, the NEO or their beneficiary would receive a lump sum cash payment of all accrued and unpaid salary, vacation and benefits, and the SERP and DCP benefits discussed above. Please refer to the "Pension Benefits" section starting on page 33 for information regarding benefits available under the Pension Plan. In addition, the outstanding performance share, restricted stock and AIP awards would have been payable as described in the "Retirement" section above. We also currently provide a survivor benefit to the beneficiaries of all active and retired employees, payable upon the employee's death. The survivor benefit is $10,000 for active employees and $5,000 for retired employees.

Resignation or Termination

In the event of resignation or termination, the NEO would receive a lump sum cash payment of all accrued and unpaid salary, vacation and benefits, and the SERP and DCP benefits discussed above. Please refer to the "Pension Benefits" section for information regarding benefits available under the Pension Plan. The NEO would also be entitled to continue health insurance benefits, at his or her own cost, as mandated by COBRA, or to elect retiree medical coverage if eligible to do so. All outstanding equity and annual incentive awards would have terminated, unless the Board took other action in its sole discretion.

Retirement Agreement with Mr. Heidtbrink

On May 1, 2017, the Company entered into a retirement agreement with Mr. Heidtbrink in connection with his retirement from the Company. The agreement provided for the forfeiture of performance share awards granted in 2017 to Mr. Heidtbrink, and the vesting of prorated performance share awards granted prior to 2017.

Pay Ratio Disclosure

The annual total compensation of Mr. Bassham, the Chairman of the Board, President and CEO of Great Plains, KCP&L and GMO, for fiscal year 2017, as reported in the Summary Compensation Table included in this Form 10-K/A, was $5,187,320. The annual total compensation of the median employee, excluding our CEO, for fiscal year 2017 was $153,753. As a result, we estimate that the ratio of the annual total compensation of our CEO to the annual total compensation of the median employee for fiscal year 2017 was 34 to 1.

As of October 1, 2017, we had 2,732 employees and used "total cash compensation" as a consistently applied compensation measure for all employees, excluding our CEO. Total cash compensation for all employees, excluding our CEO, consisted of regular earnings, overtime, and additional cash payments, inclusive of incentives. We identified a group of employees who were paid within a +/- 5% range of the median total cash compensation. This group was reduced by using a +/- 5% range on median length of service, then further reduced by reviewing three years of W-2 income after which we identified the median employee. After identifying the median employee, we calculated annual total compensation for such employee using the methodology used for calculating the total compensation of our NEOs (including our CEO) as set forth in the Summary Compensation Table on page 26. The CEO pay ratio calculation was completed by comparing the annual total compensation of the CEO with the annual total compensation of the median employee.

DIRECTOR COMPENSATION

We compensate our non-employee directors as summarized below. Mr. Bassham is an officer of the Company and does not receive compensation for his service on the Board. Non-employee directors receive an annual retainer which is paid quarterly. For the first quarter of 2017, non-employee directors were paid $40,000, representing one-fourth of the $160,000 annual retainer. Of this retainer amount, $20,000 was paid in cash, and $20,000 was paid in common stock (valued on the grant date and rounded to the next highest whole share) through our LTIP. Beginning in the second quarter of 2017, after consultation with Mercer and review of benchmarking data, the cash retainer and equity components of the non-employee directors' compensation were changed. For each of the second, third and fourth quarters, non-employee directors were paid $22,500 as a cash retainer and $22,500 as an equity retainer. Non-employee director compensation also included $1,500 for each Board and committee meeting attended in excess of six meetings per year and $1,500 for special finance committee meetings in excess of two meetings per year. Additional Board and committee meeting fees paid in 2017 were $12,000 for Mr. Grimes; $13,500 for Messrs. Ferguson, Hyde and Sherman; $15,000 for Ms. Murtlow and $16,500 for Mr. Forsee and Ms. Price. Consistent with 2016, the Lead Director received an additional annual cash fee of $20,000, and the annual fees to the Board's Audit, Compensation and Development, and Governance committee chairs remained $12,500, $10,000 and $7,500, respectively. Under our Corporate Governance Guidelines, directors are expected to hold Company stock at a level of at least five times their annual cash retainer.

Directors may defer the receipt of all or part of the cash retainer or meeting fees through our non-qualified DCP or all or part of the equity retainer through issuance of Deferred Share Units ("DSU") under the LTIP. Directors must make their deferral elections prior to the year in which such compensation would be paid. The number of DSUs granted is equal to the number of shares of common stock that otherwise would have been payable to the director. As of the date any dividend is paid to common stock shareholders, each DSU account is credited with additional DSUs equal to the number of shares of common stock that could have been purchased (at the closing price of our common stock on that date) with the amount which would have been paid as dividends on the number of shares equal to the number of DSUs. DSUs will be converted into an equal amount of shares of common stock on the first January 31 following the date the director's service on the Board terminates or such other January 31 selected by the director. The number of whole shares of common stock will be distributed to the director, with any fractional share paid in cash.

We offer life and medical insurance coverage to only the current non-employee directors who were first appointed before May 1, 2006, and their families. The aggregate premium paid by us for this coverage in 2017 was $3,419. We pay or reimburse directors for travel, lodging and related expenses that they incur in attending Board and committee meetings. From time to time, we have also paid the expenses incurred by directors' spouses in accompanying the directors to one Board meeting, and we may continue to do so in future years. We also match up to $10,000 per year of charitable donations made by each director to 501(c)(3) organizations that meet our strategic giving priorities and are located in our service territories. Additionally, in order to encourage ongoing development, we also reimburse directors for the payment of certain professional fees.

The following table outlines all compensation paid to our non-employee directors in 2017. We have omitted the columns titled "Option Awards" and "Non-Equity Incentive Plan Compensation" because our non-employee directors did not receive such compensation in 2017.

Director Compensation

Name	Fees Earned or Paid in Cash(1) ($)	Stock Awards(2) ($)	Nonqualified Deferred Compensation Earnings(3) ($)	All Other Compensation(4) ($)	Total ($)
Dr. Bodde	101,000	87,554	139,332	10,076	337,962
Mr. Ferguson	108,500	87,554	—	20,268	216,322
Mr. Forsee	124,000	87,554	49,257	10,000	270,811
Mr. Grimes	99,500	87,554	—	—	187,054
Mr. Hyde	113,500	87,554	28,947	6,300	236,301
Mr. Mitchell	42,500	42,530	15,245	10,076	110,351
Ms. Murtlow	102,500	87,554	—	—	190,054
Ms. Price	104,000	87,554	—	15,000	206,554
Mr. Sherman	111,000	87,554	—	10,000	208,554

(1) The amounts shown include quarterly cash retainers of $20,000 for all non-employee directors for each Board and committee meeting attended in the first quarter of 2017. Beginning in the second quarter of 2017, non-employee directors received a quarterly cash retainer of $22,500. Additional Board and committee fees were paid for meetings in excess of six board and six committee meetings annually. Cash fees were paid for Mr. Forsee ($20,000) as Lead Director, and Messrs. Hyde ($12,500), Sherman ($10,000) and Ferguson ($7,500) as Committee chairs. Mr. Mitchell retired effective May 2, 2017.

(2) The amounts shown include quarterly equity retainers of $20,000 for the first quarter of 2017 and $22,500 for the second, third and fourth quarters of 2017. These equity retainers are the aggregate grant date fair values of Director Shares and DSUs granted during 2017 computed in accordance with the FASB ASC Topic 718. The DSUs are not subject to any service-based vesting conditions. As of December 31, 2017, the following directors held DSUs as follows: Dr. Bodde 26,949 DSUs; Mr. Ferguson 32,783 DSUs; Mr. Forsee 30,060 DSUs; Mr. Grimes 9,070 DSUs; Mr. Hyde 15,441 DSUs; Mr. Mitchell 10,596 DSUs; Ms. Murtlow 9,070 DSUs; and Ms. Price 5,725 DSUs.

(3) The amounts shown represent the above-market earnings during 2017 on nonqualified deferred compensation.

(4) The amounts shown consist of, as applicable for each director, matched charitable contributions, spousal travel, and premiums for life insurance and health insurance. The matched charitable contributions reported in this column are: Dr. Bodde, $10,000; Mr. Ferguson, $17,000; Mr. Forsee, $10,000; Mr. Hyde, $ 6,300; Ms. Price, $15,000; Mr. Sherman, $10,000; including $10,000 made in honor of Mr. Mitchell's retirement. The Company also paid the following amounts for life and health insurance during 2017: Dr. Bodde, $76; Mr. Ferguson, $3,268; and Mr. Mitchell, $76.

COMPENSATION COMMITTEE INTERLOCKS AND INSIDER PARTICIPATION

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

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS, DIRECTORS AND OFFICERS

The following tables show, as of March 6, 2018, beneficial ownership of Company common stock by (i) each NEO, (ii) each director, (iii) all directors and executive officers as a group and (iv) each shareholder who the Company knows is a beneficial owner of more than five percent of the outstanding shares of the

Company's common stock (based on SEC filings). The total of all shares owned by directors and executive officers represents less than one percent of our outstanding shares. Our management has no knowledge of any person (as defined by the SEC) who owns beneficially more than five percent of our common stock, except as described below. Except as noted below, the Company believes that the persons listed have sole voting and investment power with respect to the securities listed.

Security Ownership of Directors and Executive Officers

Name	Beneficially Owned Shares (#)	Share Equivalents to be Settled in Stock[1] (#)	Total Share Interest (#)	Percent Of Class (%)
Named Executive Officers				
Terry Bassham	308,475 (2)	—	308,475	*
Kevin E. Bryant	48,906 (3)	—	48,906	*
Heather A. Humphrey	61,115 (4)	—	61,115	*
Lori A. Wright	25,344 (5)	—	25,344	*
Charles A. Caisley	33,206 (6)	—	33,206	*
Scott H. Heidtbrink	— (7)	—	—	*
Non-Management Directors				
David L. Bodde	26,744 (8)	26,949	53,693	*
Randall C. Ferguson, Jr.	7,768 (9)	32,783	40,551	*
Gary D. Forsee	5,572	30,060	35,632	*
Scott D. Grimes	1,318	9,070	10,388	*
Thomas D. Hyde	4,637	15,441	20,078	*
Ann D. Murtlow	5,520	9,070	14,590	*
Sandra J. Price	—	5,172	5,172	*
John J. Sherman	58,529	—	58,529	*
All Great Plains Energy Directors and Executive Officers as a Group (17 persons)				*

*less than one percent

(1) The shares listed are for Director DSUs awarded under our LTIP that will be settled in stock on a 1-for-1 basis and distributed following termination of service on the Board pursuant to elections made by the director.

(2) The amount shown includes 59,797 restricted stock shares.

(3) The amount shown includes 20,249 restricted stock shares.

(4) The amount shown includes 12,967 restricted stock shares.

(5) The amount shown includes 5,999 restricted stock shares and 190 shares held in the 401(k) plan.

(6) The amount shown includes 5,749 restricted stock shares, 700 shares held in joint tenancy with Mr. Caisley's spouse and 100 shares held with his daughter.

(7) Mr. Heidtbrink retired from the Company effective May 1, 2017.

(8) All 26,744 shares are held in joint tenancy with Dr. Bodde's spouse.

(9) The amount shown includes 5,743 shares held in joint tenancy with Mr. Ferguson's spouse.

Beneficial Ownership of 5 Percent or More

	Beneficial Ownership of Common Stock (Based on Schedule 13G/A Filing)	Percentage of Common Shares Outstanding(4)
BlackRock Inc.(1) 55 East 52nd Street New York, NY 10055	21,497,371	9.96
The Vanguard Group(2) 100 Vanguard Blvd. Malvern, PA 19355	19,317,619	8.95
Franklin Resources, Inc.(3) One Franklin Parkway San Mateo, CA 94403-1906	11,010,585	5.10

(1) Based on information provided in Schedule 13G/A filed by BlackRock Inc. ("BlackRock") and its affiliated reporting persons on January 23, 2018. The BlackRock Schedule 13G/A states that as of December 31, 2017 the reporting persons collectively held sole voting power with respect to 20,678,644 shares and sole dispositive power with respect to 21,497,371 shares.

(2) Based on information provided in Schedule 13G/A filed by The Vanguard Group ("Vanguard") and its affiliated reporting persons on February 9, 2018. The Vanguard Schedule 13G/A states that as of December 31, 2017 the reporting persons collectively held sole voting power with respect to 145,284 shares, shared voting power with respect to 81,529 shares, sole dispositive power with respect to 19,138,542 shares, shared dispositive power with respect to179,077 shares and an aggregate beneficial ownership of 19,317,619 shares.

(3) Based on information provided in Schedule 13G/A filed by Franklin Resources, Inc. ("Franklin Resources") and its affiliated reporting persons on February 6, 2018. The Franklin Resources Schedule 13G/A states that as of December 31, 2017 the reporting persons collectively held sole voting power with respect to 10,907,312 and sole dispositive power with respect to 11,010,585 shares.

(4) The percentage is based on approximately 215,784,153 shares of our common stock outstanding as of March 6, 2018.

Equity Compensation Plans

Great Plains Energy's LTIP is an equity compensation plan approved by its shareholders. The LTIP permits the grant of restricted stock, restricted stock units, bonus shares, stock options, stock appreciation rights, limited stock appreciation rights, director shares, director DSUs and performance shares to directors, officers and other employees of Great Plains Energy and KCP&L. KCP&L does not have an equity compensation plan; however, KCP&L officers and certain employees participate in Great Plains Energy's LTIP.

The following table provides information, as of December 31, 2017, regarding the number of common shares to be issued upon exercise of outstanding options, warrants and rights, their weighted average exercise price, and the number of shares of common stock remaining available for future issuance. The table excludes shares issued or issuable under Great Plains Energy's defined contribution savings plans.

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders			
Great Plains Energy Long-Term Incentive Plan	684,238 [(1)]	$ — [(2)]	4,022,044
Equity compensation plans not approved by security holders	—	—	—
Total	684,238 [(1)]	$ — [(2)]	4,022,044

(1) Includes 545,087 performance shares at target performance levels and director DSUs for 139,151 shares of Great Plains Energy common stock outstanding at December 31, 2017.

(2) The performance shares and director DSUs have no exercise price and therefore are not reflected in the weighted average exercise price.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

RELATED PARTY TRANSACTIONS

The Board has adopted a written policy governing the identification, review, approval, consideration or ratification of related party transactions. The policy applies to any transaction in which the Company (including any of its subsidiaries) was, is or will be a participant, the amount involved exceeds $120,000 in the aggregate, and any related party had, has or will have a direct or indirect material interest, but excludes any transaction that meets the preapproval thresholds set forth in our related party transaction policy. There were no related party transactions in 2017. Related party transactions are to be submitted to the Governance Committee for consideration at the next Governance Committee meeting or, if it is not practicable or desirable for the Company to wait until the next Governance Committee meeting, to the Chair of the Governance Committee. The Governance Committee (or the Chair) intends to approve only those related party transactions that are in, or are not inconsistent with, the best interests of the Company and its shareholders. The Chair of the Governance Committee reports to the Governance Committee at its next meeting any approval under the related party transactions policy pursuant to delegated authority.

DIRECTOR INDEPENDENCE

Our Corporate Governance Guidelines require that a majority of our directors be independent as determined in accordance with the NYSE listing standards, as well as other independence standards that the Board may adopt. The NYSE listing standards provide that no director can qualify as independent unless the Board affirmatively determines that the director has no material relationship with the listed company. The Board has adopted Director Qualification Standards, that are contained in the Company’s Corporate Governance Guidelines, to assist in making director independence determinations. Our Corporate Governance Guidelines are available on our website, *www.greatplainsenergy.com*. Our Director Qualification Standards conform to the NYSE objective independence standards.

The Governance Committee reviewed the applicable legal standards for Board and committee member independence and the Director Qualification Standards. The Governance Committee also reviewed an analysis of the information provided by each director in the annual questionnaire and a report of transactions between the Company and director-affiliated entities. The Governance Committee reported its independence determination recommendations to the full Board, and the Board made its independence determinations based on the Governance Committee's report and the supporting information. In making its independence determinations, the Board considered ordinary course commercial, charitable, and other transactions. None of the identified transactions were considered "related person" or "related party" transactions required to be under Item 404 of Regulation S-K or our Related Party Transaction Policy, respectively.

Based on this review, the Board affirmatively determined at its February 2018 meeting that the following directors are independent under the NYSE listing standards and the Director Qualification Standards:

David L. Bodde	Scott D. Grimes	Sandra J. Price
Randall C. Ferguson, Jr.	Thomas D. Hyde	John J. Sherman
Gary D. Forsee	Ann D. Murtlow	

Only independent directors are members of our Audit, Compensation and Development, and Governance committees. All members of our Audit Committee and Compensation and Development Committee also meet the additional NYSE and SEC independence requirements.

The Board determined that Mr. Bassham is not independent under the NYSE listing standards and the Director Qualification Standards because he is an executive officer of the Company.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Audit and Audit-Related Fees

Deloitte & Touche has acted as our independent registered public accounting firm since 2002. The following table sets forth the aggregate fees billed by Deloitte & Touche for audit services rendered in connection with the consolidated financial statements and reports for 2017 and 2016, and for other services rendered during 2017 and 2016 on behalf of the Company and its subsidiaries (all of which were pre-approved by the Audit Committee), as well as all out-of-pocket costs incurred in connection with these services:

Fee Category	2017	2016
Audit Fees	$2,661,600	$2,316,425
Audit-Related Fees	44,000	42,000
Tax Fees	37,802	223,818
All Other Fees	12,395	4,395
Total Fees:	$2,755,797	$2,586,638

Audit Fees: Consist of fees billed for professional services rendered for the audits of the annual consolidated financial statements of the Company and its subsidiaries and reviews of the interim condensed consolidated financial statements included in quarterly reports. Audit fees also include: services provided by Deloitte & Touche in connection with statutory and regulatory filings or engagements; audit reports on the effectiveness of internal control over financial reporting and other attest services, except those not required by statute or regulation; services related to filings with the SEC, including comfort letters, consents and assistance with and review of documents filed with the SEC; and accounting research in support of the audit.

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

Tax Fees: Consist of fees billed for tax compliance and related support of tax returns and other tax services, including assistance with tax audits, and tax research and planning.

All Other Fees: Consist of fees for all other services other than those described above.

Audit Committee Pre-Approval of Audit and Permissible Non-Audit Services

The Audit Committee has adopted policies and procedures for the pre-approval of all audit services, audit-related services, tax services and other services to be provided by the independent registered public accounting firm for the Company and its subsidiaries. Under these policies and procedures, the Audit Committee may pre-approve certain types of services, up to the aggregate fee levels it sets. Any proposed service within a pre-approved type of service that would cause the applicable fee level to be exceeded cannot be provided unless the Audit Committee either amends the applicable fee level or specifically approves the proposed service. The Audit Committee, as well, may specifically approve audit, audit-related, tax or other services on a case-by-case basis. Pre-approval is generally provided for up to one year, unless the Audit Committee specifically provides for a different period. The Company provides quarterly updates to the Audit Committee regarding actual fees spent with respect to pre-approved services. The Chair of the Audit Committee may pre-approve audit, audit-related, tax and other services provided by the independent registered public accounting firm as required between meetings and report such pre-approval at the next Audit Committee meeting.

PART IV
ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES EXHIBIT INDEX

Exhibits

Exhibit Number		Description of Document	Registrant
2.1	*	Agreement and Plan of Merger, dated as of May 29, 2016, by and among Westar Energy, Inc., Great Plains Energy Incorporated and, from and after its accession thereto, Merger Sub (as defined therein) (Exhibit 2.1 to Form 8-K filed on May 31, 2016).	Great Plains Energy
2.2	*	Amended and Restated Merger Agreement, dated as of July 9, 2017, by and among Great Plains Energy Incorporated, Westar Energy, Inc., Monarch Energy Holding, Inc., King Energy, Inc. and, solely for the purposes set forth therein, GP Star, Inc. (Exhibit 2.1 to Form 8-K filed on July 10, 2017).	Great Plains Energy
3.1	*	Articles of Incorporation of Great Plains Energy Incorporated, as amended effective September 26, 2016 (Exhibit 3.1 to Form 10-Q for the quarter ended September 30, 2016).	Great Plains Energy
3.2	*	Amended and Restated By-laws of Great Plains Energy Incorporated, as amended December 10, 2013 (Exhibit 3.1 to Form 8-K filed on December 16, 2013).	Great Plains Energy
3.3	*	Amended and Restated Articles of Consolidation of Kansas City Power & Light Company, restated as of May 6, 2014 (Exhibit 3.2 to Form 10-Q for the quarter ended March 31, 2014).	KCP&L
3.4	*	Amended and Restated By-laws of Kansas City Power & Light Company, as amended December 10, 2013 (Exhibit 3.3 to Form 8-K filed on December 16, 2013).	KCP&L
4.1	*	Indenture, dated as of June 1, 2004, between Great Plains Energy Incorporated and BNY Midwest Trust Company, as trustee (Exhibit 4.4 to Form 8-A/A filed on June 14, 2004).	Great Plains Energy
4.2	*	First Supplemental Indenture, dated as of June 14, 2004, between Great Plains Energy Incorporated and BNY Midwest Trust Company, as trustee (Exhibit 4.5 to Form 8-A/A filed on June 14, 2004).	Great Plains Energy
4.3	*	Second Supplemental Indenture, dated as of September 25, 2007, between Great Plains Energy Incorporated and The Bank of New York Trust Company, N.A., as trustee (Exhibit 4.1 to Form 8-K filed on September 26, 2007).	Great Plains Energy

4.4	*	Third Supplemental Indenture, dated as of August 13, 2010, between Great Plains Energy Incorporated and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.1 to Form 8-K filed on August 13, 2010).	Great Plains Energy
4.5	*	Fourth Supplemental Indenture, dated as of May 19, 2011, between Great Plains Energy Incorporated and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.1 to Form 8-K filed on May 19, 2011).	Great Plains Energy
4.6	*	Fifth Supplemental Indenture, dated as of March 9, 2017, between Great Plains Energy and The Bank of New York Trust Company, N.A. as trustee (Exhibit 4.1 to Form 8-K filed on March 9, 2017).	Great Plains Energy
4.7	*	Subordinated Indenture, dated as of May 18, 2009, between Great Plains Energy Incorporated and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.1 to Form 8-K filed on May 19, 2009).	Great Plains Energy
4.8	*	Supplemental Indenture No. 1, dated as of May 18, 2009, between Great Plains Energy Incorporated and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.2 to Form 8-K filed on May 19, 2009).	Great Plains Energy
4.9	*	Supplemental Indenture No. 2, dated as of March 22, 2012, between Great Plains Energy Incorporated and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.1 to Form 8-K filed on March 23, 2012).	Great Plains Energy
4.10	*	Indenture, dated as of August 24, 2001, between Aquila, Inc. and BankOne Trust Company, N.A., as trustee (Exhibit 4(d) to Registration Statement on Form S-3 (File No. 333-68400) filed by Aquila, Inc. on August 27, 2001).	Great Plains Energy
4.11	*	Second Supplemental Indenture, dated as of July 3, 2002, between Aquila, Inc. and BankOne Trust Company, N.A., as trustee (Exhibit 4(c) to Form S-4 (File No. 333-100204) filed by Aquila, Inc. on September 30, 2002).	Great Plains Energy
4.12	*	General Mortgage and Deed of Trust, dated as of December 1, 1986, between Kansas City Power & Light Company and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee (Exhibit 4.12 to Form 10-K for the year ended December 31, 2017).	Great Plains Energy KCP&L
4.13	*	Fifth Supplemental Indenture, dated as of September 15, 1992, between Kansas City Power & Light Company and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee (Exhibit 4.13 to Form 10-K for the year ended December 31, 2017).	Great Plains Energy KCP&L

4.14	*	Seventh Supplemental Indenture, dated as of October 1, 1993, between Kansas City Power & Light Company and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee (Exhibit 4.14 to Form 10-K for the year ended December 31, 2017).	Great Plains Energy KCP&L
4.15	*	Eighth Supplemental Indenture, dated as of December 1, 1993, between Kansas City Power & Light Company and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee. (Exhibit 4.15 to Form 10-K for the year ended December 31, 2017).	Great Plains Energy KCP&L
4.16	*	Eleventh Supplemental Indenture, dated as of August 15, 2005, between Kansas City Power & Light Company and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee (Exhibit 4.2 to Form 10-Q for the quarter ended September 30, 2005).	Great Plains Energy KCP&L
4.17	*	Twelfth Supplemental Indenture, dated as of March 1, 2009, between Kansas City Power & Light Company and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee (Exhibit 4.2 to Form 8-K filed on March 24, 2009).	Great Plains Energy KCP&L
4.18	*	Thirteenth Supplemental Indenture, dated as of March 1, 2009, between Kansas City Power & Light Company and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee (Exhibit 4.3 to Form 8-K filed on March 24, 2009).	Great Plains Energy KCP&L
4.19	*	Fourteenth Supplemental Indenture, dated as of March 1, 2009, between Kansas City Power & Light Company and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee (Exhibit 4.4 to Form 8-K filed on March 24, 2009).	Great Plains Energy KCP&L
4.20	*	Fifteenth Supplemental Indenture, dated as of June 30, 2011, between Kansas City Power & Light Company and UMB Bank, N.A. (formerly United Missouri Bank of Kansas City, N.A.), as trustee (Exhibit 4.1 to Form 10-Q for the quarter ended June 30, 2011).	Great Plains Energy KCP&L
4.21	*	Indenture, dated as of December 1, 2000, between Kansas City Power & Light Company and The Bank of New York, as trustee (Exhibit 4(a) to Form 8-K filed on December 18, 2000).	Great Plains Energy KCP&L
4.22	*	Indenture, dated as of March 1, 2002, between Kansas City Power & Light Company and The Bank of New York, as trustee (Exhibit 4.1.b. to Form 10-Q for the quarter ended March 31, 2002).	Great Plains Energy KCP&L

4.23	*	Supplemental Indenture No. 1, dated as of November 15, 2005, between Kansas City Power & Light Company and The Bank of New York, as trustee (Exhibit 4.2.j to Form 10-K for the year ended December 31, 2005).	Great Plains Energy KCP&L
4.24	*	Indenture, dated as of May 1, 2007, between Kansas City Power & Light Company and The Bank of New York Trust Company, N.A., as trustee (Exhibit 4.1 to Form 8-K filed on June 4, 2007).	Great Plains Energy KCP&L
4.25	*	Supplemental Indenture No. 1, dated as of June 4, 2007, between Kansas City Power & Light Company and The Bank of New York Trust Company, N.A., as trustee (Exhibit 4.2 to Form 8-K filed on June 4, 2007).	Great Plains Energy KCP&L
4.26	*	Supplemental Indenture No. 2, dated as of March 11, 2008, between Kansas City Power & Light Company and The Bank of New York Trust Company, N.A., as trustee (Exhibit 4.2 to Form 8-K filed on March 11, 2008).	Great Plains Energy KCP&L
4.27	*	Supplemental Indenture No. 3, dated as of September 20, 2011, between Kansas City Power & Light Company and The Bank of New York Mellon Trust Company, N.A., Trustee (Exhibit 4.1 to Form 8-K filed on September 20, 2011).	Great Plains Energy KCP&L
4.28	*	Supplemental Indenture No. 4, dated as of March 14, 2013, between Kansas City Power & Light Company and The Bank of New York Mellon Trust Company, N.A., Trustee (Exhibit 4.1 to Form 8-K filed on March 14, 2013).	Great Plains Energy KCP&L
4.29	*	Supplemental Indenture No. 5, dated as of August 18, 2015, between Kansas City Power & Light Company and The Bank of New York Mellon Trust Company, N.A., Trustee (Exhibit 4.1 to Form 8-K filed on August 18, 2015).	Great Plains Energy KCP&L
4.30	*	Supplemental Indenture No. 6 dated as of June 15, 2017 between KCP&L and The Bank of New York Mellon Trust Company, N.A., as trustee (Exhibit 4.1 to Form 8-K filed on June 15, 2017).	Great Plains Energy KCP&L
4.32	*	Note Purchase Agreement, dated August 16, 2013, among KCP&L Greater Missouri Operations Company and the purchasers party thereto (Exhibit 4.1 to Form 8-K filed on August 19, 2013).	Great Plains Energy
10.1	*+	Great Plains Energy Incorporated Amended Long-Term Incentive Plan, effective on May 7, 2002 (Exhibit 10.1.a to Form 10-K for the year ended December 31, 2002).	Great Plains Energy KCP&L
10.2	*+	Great Plains Energy Incorporated Amended Long-Term Incentive Plan, as amended effective on May 1, 2007 (Exhibit 10.1 to Form 8-K filed on May 4, 2007).	Great Plains Energy KCP&L

10.3	*+	Great Plains Energy Incorporated Amended Long-Term Incentive Plan, as amended effective on May 3, 2011 (Exhibit 10.1 to Form 8-K filed on May 6, 2011).	Great Plains Energy KCP&L
10.4	*+	Great Plains Energy Incorporated Amended Long-Term Incentive Plan, as amended effective on January 1, 2014 (Exhibit 10.1 to Form 10-Q for the quarter ended June 30, 2013).	Great Plains Energy KCP&L
10.5	*+	Great Plains Energy Incorporated Amended Long-Term Incentive Plan, as amended effective on May 3, 2016 (Exhibit 10.4 to Form 10-Q for the quarter ended June 30, 2016).	Great Plains Energy KCP&L
10.6	*+	Great Plains Energy Incorporated Long-Term Incentive Plan Awards Standards and Performance Criteria Effective as of January 1, 2013 (Exhibit 10.3 to Form 10-Q for the quarter ended March 31, 2013).	Great Plains Energy KCP&L
10.7	*+	Great Plains Energy Incorporated Long-Term Incentive Plan Awards Standards and Performance Criteria Effective as of January 1, 2014 (Exhibit 10.3 to Form 10-Q for the quarter ended March 31, 2014).	Great Plains Energy KCP&L
10.8	*+	Great Plains Energy Incorporated Long-Term Incentive Plan Awards Standards and Performance Criteria Effective as of January 1, 2015 (Exhibit 10.3 to Form 10-Q for the quarter ended March 31, 2015).	Great Plains Energy KCP&L
10.9	*+	Great Plains Energy Incorporated Long-Term Incentive Plan Awards Standards and Performance Criteria Effective as of January 1, 2016 (Exhibit 10.3 to Form 10-Q for the quarter ended March 31, 2016).	Great Plains Energy KCP&L
10.10	*+	Great Plains Energy Incorporated Long-Term Incentive Plan Awards Standards and Performance Criteria Effective as of January 1, 2017 (Exhibit 10.3 to Form 10-Q for the quarter ended March 31, 2017).	Great Plains Energy KCP&L
10.11	*+	Letter Agreement dated March 7, 2017, by and between Michael L. Deggendorf, Great Plains Energy Incorporated, Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company (Exhibit 10.5 to Form 10-Q for the quarter ended March 31, 2017).	Great Plains Energy KCP&L
10.12	*+	Retirement Agreement dated May 1, 2017, by and between Scott H. Heidtbrink, Great Plains Energy Incorporated, Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company (Exhibit 10.6 to Form 10-Q for the quarter ended March 31, 2017).	Great Plains Energy KCP&L
10.13	*+	Form of 2013 three-year Performance Share Agreement (Exhibit 10.1 to Form 10-Q for the quarter ended March 31, 2013).	Great Plains Energy KCP&L

10.14	*+	Form of 2013 Restricted Stock Agreement (Exhibit 10.2 to Form 10-Q for the quarter ended March 31, 2013).	Great Plains Energy KCP&L
10.15	*+	Form of 2014 three-year Performance Share Agreement (Exhibit 10.1 to Form 10-Q for the quarter ended March 31, 2014).	Great Plains Energy KCP&L
10.16	*+	Form of 2014 Restricted Stock Agreement (Exhibit 10.2 to Form 10-Q for the quarter ended March 31, 2014).	Great Plains Energy KCP&L
10.17	*+	Form of 2015 three-year Performance Share Agreement (Exhibit 10.1 to Form 10-Q for the quarter ended March 31, 2015).	Great Plains Energy KCP&L
10.18	*+	Form of 2015 Restricted Stock Agreement (Exhibit 10.2 to Form 10-Q for the quarter ended March 31, 2015).	Great Plains Energy KCP&L
10.19	*+	Form of 2016 three-year Performance Share Agreement (Exhibit 10.1 to Form 10-Q for the quarter ended March 31, 2016).	Great Plains Energy KCP&L
10.20	*+	Form of 2016 Restricted Stock Agreement (Exhibit 10.2 to Form 10-Q for the quarter ended March 31, 2016).	Great Plains Energy KCP&L
10.21	*+	Form of 2017 three-year Performance Share Agreement (Exhibit 10.1 to Form 10-Q for the quarter ended March 31, 2017).	Great Plains Energy KCP&L
10.22	*+	Form of 2017 Restricted Stock Agreement (Exhibit 10.2 to Form 10-Q for the quarter ended March 31, 2017).	Great Plains Energy KCP&L
10.23	*+	Aquila, Inc. 2002 Omnibus Incentive Compensation Plan (Exhibit 10.3 to Form 10-Q for the quarter ended September 30, 2002, filed by Aquila, Inc.).	Great Plains Energy KCP&L
10.24	*+	Great Plains Energy Incorporated, Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company Annual Incentive Plan amended effective as of January 1, 2016 (Exhibit 10.4 to Form 10-Q for the quarter ended March 31, 2016).	Great Plains Energy KCP&L
10.25	*+	Form of Indemnification Agreement with each officer and director (Exhibit 10-f to Form 10-K for year ended December 31, 1995).	Great Plains Energy KCP&L
10.26	*+	Form of Conforming Amendment to Indemnification Agreement with each officer and director (Exhibit 10.1.a to Form 10-Q for the quarter ended March 31, 2003).	Great Plains Energy KCP&L
10.27	*+	Form of Indemnification Agreement with each director and officer (Exhibit 10.1 to Form 8-K filed on December 8, 2008).	Great Plains Energy KCP&L

10.28	*+	Form of Indemnification Agreement with officers and directors (Exhibit 10.1.p to Form 10-K for the year ended December 31, 2005).	Great Plains Energy KCP&L
10.29	*+	Form of Indemnification Agreement with officers and directors (Exhibit 10.1 to Form 8-K filed on December 16, 2013).	Great Plains Energy KCP&L
10.30	*+	Form of Change in Control Severance Agreement with other executive officers of Great Plains Energy Incorporated and Kansas City Power & Light Company (Exhibit 10.1.e to Form 10-Q for the quarter ended September 30, 2006).	Great Plains Energy KCP&L
10.31	*+	Great Plains Energy Incorporated Supplemental Executive Retirement Plan (As Amended and Restated for I.R.C. §409A) (Exhibit 10.1.10 to Form 10-Q for the quarter ended September 30, 2007).	Great Plains Energy KCP&L
10.32	*+	Great Plains Energy Incorporated Supplemental Executive Retirement Plan (As Amended and Restated for I.R.C. §409A), as amended February 10, 2009 (Exhibit 10.1.29 to Form 10-K for the year ended December 31, 2008.)	Great Plains Energy KCP&L
10.33	*+	Great Plains Energy Incorporated Supplemental Executive Retirement Plan (As Amended and Restated for I.R.C. §409A), as amended December 8, 2009 (Exhibit 10.1.27 to Form 10-K for the year ended December 31, 2009).	Great Plains Energy KCP&L
10.34	*+	Amendment dated October 28, 2014, to the Great Plains Energy Incorporated Supplemental Executive Retirement Plan as amended and restated on December 8, 2009 (Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 2014).	Great Plains Energy KCP&L
10.35	*+	Great Plains Energy Incorporated Nonqualified Deferred Compensation Plan (As Amended and Restated for I.R.C. §409A) (Exhibit 10.1.11 to Form 10-Q for the quarter ended September 30, 2007).	Great Plains Energy KCP&L
10.36	*+	Great Plains Energy Incorporated Nonqualified Deferred Compensation Plan (As Amended and Restated for I.R.C. §409A), amended effective January 1, 2010 (Exhibit 10.1.5 to Form 10-Q for the quarter ended March 31, 2010).	Great Plains Energy KCP&L
10.37	*	Joint Motion and Settlement Agreement, dated as of February 26, 2008, among Great Plains Energy Incorporated, Kansas City Power & Light Company, the Kansas Corporation Commission Staff, the Citizens' Utility Ratepayers Board, Aquila, Inc. d/b/a Aquila Networks, Black Hills Corporation, and Black Hills/Kansas Gas Utility Company, LLC (Exhibit 10.1.7 to Form 10-Q for the quarter ended March 31, 2008).	Great Plains Energy KCP&L

10.38	*	Credit Agreement, dated as of August 9, 2010, among Great Plains Energy Incorporated, Certain Lenders, Bank of America, N.A., as Administrative Agent, and Union Bank, N.A. and Wells Fargo Bank, National Association, as Syndication Agents, Barclays Bank PLC and U.S. Bank National Association, as Documentation Agents, Banc of America Securities LLC, Union Bank, N.A. and Wells Fargo Securities, LLC as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 2010).	Great Plains Energy
10.39	*	First Amendment to Credit Agreement, dated as of December 9, 2011, among Great Plains Energy Incorporated, Certain Lenders, Union Bank, N.A. and Wells Fargo Bank, National Association, as Syndication Agents, Bank of America, N.A., as Administrative Agent, Barclays Bank PLC and U.S. Bank National Association, as Documentation Agents, Merrill Lynch, Pierce, Fenner & Smith Incorporated, Union Bank, N.A. and Wells Fargo Securities, LLC as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.59 to Form 10-K for the year ended December 31, 2011).	Great Plains Energy
10.40	*	Second Amendment to Credit Agreement, dated as of October 17, 2013, among Great Plains Energy Incorporated, Certain Lenders, Bank of America, N.A., JPMorgan Chase Bank, N.A. and Union Bank, N.A., as Syndication Agents and Wells Fargo Bank, National Association, as Administrative Agent, and Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, J.P. Morgan Securities LLC, and Union Bank, N.A., as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 2013).	Great Plains Energy
10.41	*	First Extension Agreement and Waiver, dated as of December 17, 2014, among Great Plains Energy Incorporated, Certain Lenders, Bank of America, N.A., JPMorgan Chase Bank, N.A., and MUFG Union Bank, N.A., as Syndication Agents and Wells Fargo Bank, National Association, as Administrative Agent, Swing Line Lender and an Issuer, Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, J.P. Morgan Securities LLC, and MUFG Union Bank, N.A., as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.37 to Form 10-K for the year ended December 31, 2014).	Great Plains Energy
10.42	*	Third Amendment to the Credit Agreement, dated as of June 13, 2016, among Great Plains Energy Incorporated, Certain Lenders, Bank of America, N.A., JPMorgan Chase Bank, N.A., and Union Bank, N.A., as Syndication Agents and Wells Fargo Bank, National Association, as Administrative Agent, and Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, J.P. Morgan Securities LLC, and Union Bank, N.A., as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.1 to Form 10-Q for the quarter ended June 30, 2016).	Great Plains Energy

10.43	*	Credit Agreement, dated as of August 9, 2010, among Kansas City Power & Light Company, Certain Lenders, Bank of America, N.A., as Administrative Agent, and Union Bank, N.A. and Wells Fargo Bank, National Association, as Syndication Agents, JPMorgan Chase Bank, N.A. and The Bank of Nova Scotia, as Documentation Agents, Banc of America Securities LLC, Union Bank, N.A. and Wells Fargo Securities, LLC as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.2 to Form 10-Q for the quarter ended September 30, 2010).	Great Plains Energy KCP&L
10.44	*	First Amendment to Credit Agreement, dated as of December 9, 2011, among Kansas City Power & Light Company, Certain Lenders, Union Bank, N.A. and Wells Fargo Bank, National Association, as Syndication Agents, Bank of America, N.A., as Administrative Agent, JPMorgan Chase Bank, N.A. and The Bank of Nova Scotia, as Documentation Agents, Merrill Lynch, Pierce, Fenner & Smith Incorporated, Union Bank, N.A. and Wells Fargo Securities, LLC as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.61 to Form 10-K for the year ended December 31, 2011).	Great Plains Energy KCP&L
10.45	*	Second Amendment to Credit Agreement, dated as of October 17, 2013, among Kansas City Power & Light Company, Certain Lenders, Bank of America, N.A., JPMorgan Chase Bank, N.A., and Union Bank, N.A., as Syndication Agents and Wells Fargo Bank, National Association, as Administrative Agent, and Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, J.P. Morgan Securities LLC, and Union Bank, N.A., as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.2 to Form 10-Q for the quarter ended September 30, 2013).	Great Plains Energy KCP&L
10.46	*	First Extension Agreement and Waiver, dated as of December 17, 2014, among Kansas City Power & Light Company, Certain Lenders, Bank of America, N.A., JPMorgan Chase Bank, N.A., and MUFG Union Bank, N.A., as Syndication Agents and Wells Fargo Bank, National Association, as Administrative Agent, Swing Line Lender and an Issuer, Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, J.P. Morgan Securities LLC, and MUFG Union Bank, N.A., as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.41 to Form 10-K for the year ended December 31, 2014).	Great Plains Energy KCP&L

10.47	*	Credit Agreement, dated as of August 9, 2010, among KCP&L Greater Missouri Operations Company, Great Plains Energy Incorporated, as Guarantor, Certain Lenders, Bank of America, N.A., as Administrative Agent, and Union Bank, N.A. and Wells Fargo Bank, National Association, as Syndication Agents, The Royal Bank of Scotland PLC and BNP Paribas , as Documentation Agents, Banc of America Securities LLC, Union Bank, N.A. and Wells Fargo Securities, LLC as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.3 to Form 10-Q for the quarter ended September 30, 2010).	Great Plains Energy
10.48	*	First Amendment to Credit Agreement, dated as of December 9, 2011, among KCP&L Greater Missouri Operations Company, Great Plains Energy Incorporated, as Guarantor, Certain Lenders, Union Bank, N.A. and Wells Fargo Bank, National Association, as Syndication Agents, Bank of America, N.A., as Administrative Agent, The Royal Bank of Scotland PLC and BNP Paribas, as Documentation Agents, Merrill Lynch, Pierce, Fenner & Smith Incorporated, Union Bank, N.A. and Wells Fargo Securities, LLC as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.63 to Form 10-K for the year ended December 31, 2011).	Great Plains Energy
10.49	*	Second Amendment to Credit Agreement, dated as of October 17, 2013, among KCP&L Greater Missouri Operations Company, Certain Lenders, Bank of America, N.A., JPMorgan Chase Bank, N.A., and Union Bank, N.A., as Syndication Agents and Wells Fargo Bank, National Association, as Administrative Agent, and Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, J.P. Morgan Securities LLC, and Union Bank, N.A., as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.3 to Form 10-Q for the quarter ended September 30, 2013).	Great Plains Energy
10.50	*	First Extension Agreement and Waiver, dated as of December 17, 2014, among KCP&L Greater Missouri Operations Company, Certain Lenders, Bank of America, N.A., JPMorgan Chase Bank, N.A., and MUFG Union Bank, N.A., as Syndication Agents and Wells Fargo Bank, National Association, as Administrative Agent, Swing Line Lender and an Issuer, Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, J.P. Morgan Securities LLC, and MUFG Union Bank, N.A., as Joint Lead Arrangers and Joint Book Managers (Exhibit 10.45 to Form 10-K for the year ended December 31, 2014).	Great Plains Energy
10.51	*	Guaranty, dated as of July 15, 2008, issued by Great Plains Energy Incorporated in favor of Union Bank of California, N.A., as successor trustee, and the holders of the Aquila, Inc., 8.27% Senior Notes due November 15, 2021 (Exhibit 10.6 to Form 8-K filed on July 18, 2008).	Great Plains Energy

10.52	*	Insurance Agreement, dated as of September 1, 2005, between Kansas City Power & Light Company and XL Capital Assurance Inc. (Exhibit 10.2.e to Form 10-K for the year ended December 31, 2005).	Great Plains Energy KCP&L
10.53	*	Insurance Agreement, dated as of September 1, 2005, between Kansas City Power & Light Company and XL Capital Assurance Inc. (Exhibit 10.2.f to Form 10-K for the year ended December 31, 2005).	Great Plains Energy KCP&L
10.54	*	Purchase and Sale Agreement, dated as of July 1, 2005, between Kansas City Power & Light Company, as Originator, and Kansas City Power & Light Receivables Company, as Buyer (Exhibit 10.2.b to Form 10-Q for the quarter ended June 30, 2005).	Great Plains Energy KCP&L
10.55	*	Receivables Sale Agreement, dated as of July 1, 2005, among Kansas City Power & Light Receivables Company, as the Seller, Kansas City Power & Light Company, as the Initial Collection Agent, The Bank of Tokyo-Mitsubishi, Ltd., New York Branch, as the Agent, and Victory Receivables Corporation (Exhibit 10.2.c to Form 10-Q for the quarter ended June 30, 2005).	Great Plains Energy KCP&L
10.56	*	Amendment No. 1, dated as of April 2, 2007, among Kansas City Power & Light Receivables Company, Kansas City Power & Light Company, The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch and Victory Receivables Corporation to the Receivables Sale Agreement dated as of July 1, 2005 (Exhibit 10.2.2 to Form 10-Q for the quarter ended March 31, 2007).	Great Plains Energy KCP&L
10.57	*	Amendment No. 2, dated as of July 11, 2008, among Kansas City Power & Light Receivables Company, Kansas City Power & Light Company, The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch and Victory Receivables Corporation to the Receivables Sale Agreement dated as of July 1, 2005 (Exhibit 10.2.1 to Form 10-Q for the quarter ended June 30, 2008).	Great Plains Energy KCP&L
10.58	*	Amendment, dated as of July 9, 2009, to Receivables Sale Agreement dated as of July 1, 2005 among Kansas City Power & Light Receivables Company, Kansas City Power & Light Company, The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch and Victory Receivables Corporation (Exhibit 10.4 to Form 8-K filed on July 13, 2009).	Great Plains Energy KCP&L
10.59	*	Amendment and Waiver, dated as of September 25, 2009, to the Receivables Sale Agreement dated as of July 1, 2005 among Kansas City Power & Light Receivables Company, Kansas City Power & Light Company, The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch and Victory Receivables Corporation (Exhibit 10.2.2 to Form 10-Q for the quarter ended September 30, 2009).	Great Plains Energy KCP&L

10.60	*	Amendment, dated as of May 5, 2010, to Receivables Sale Agreement dated as of July 1, 2005 among Kansas City Power & Light Receivables Company, Kansas City Power & Light Company, The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch and Victory Receivables Corporation (Exhibit 10.2.2 to Form 10-Q for the quarter ended March 31, 2010).	Great Plains Energy KCP&L
10.61	*	Amendment, dated as of February 23, 2011, to Receivables Sale Agreement dated as of July 1, 2005 among Kansas City Power & Light Receivables Company, Kansas City Power & Light Company, The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch and Victory Receivables Corporation (Exhibit 10.5 to Form 10-Q for the quarter ended March 31, 2011).	Great Plains Energy KCP&L
10.62	*	Amendment, dated as of September 9, 2011, to Receivables Sale Agreement dated as of July 1, 2005, among Kansas City Power & Light Receivables Company, Kansas City Power & Light Company, The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch and Victory Receivables Corporation (Exhibit 10.1 to Form 8-K filed on September 13, 2011).	Great Plains Energy KCP&L
10.63	*	Amendment dated as of September 9, 2014, to the Receivables Sales Agreement dated as of July 1, 2005, among Kansas City Power & Light Receivables Company, as the Seller, Kansas City Power & Light Company, as the Initial Collection Agent, The Bank of Tokyo-Mitsubishi, Ltd., New York Branch, as the Agent and Victory Receivables Corporation, as the Purchaser (Exhibit 10.1 to Form 8-K filed on September 15, 2014).	Great Plains Energy KCP&L
10.64	*	Amendment dated as of September 9, 2015, to the Receivables Sales Agreement dated as of July 1, 2005, among Kansas City Power & Light Receivables Company, as the Seller, Kansas City Power & Light Company, as the Initial Collection Agent, The Bank of Tokyo-Mitsubishi, Ltd., New York Branch, as the Agent and Victory Receivables Corporation, as the Purchaser (Exhibit 10.1 to Form 8-K filed on September 11, 2015).	Great Plains Energy KCP&L
10.65	*	Amendment dated as of September 9, 2016, to the Receivables Sales Agreement dated as of July 1, 2005, among Kansas City Power & Light Receivables Company, as the Seller, Kansas City Power & Light Company, as the Initial Collection Agent, The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch, as the Agent and Victory Receivables Corporation, as the Purchaser (Exhibit 10.1 to Form 8-K filed on September 13, 2016).	Great Plains Energy KCP&L

10.66	*	Purchase and Sale Agreement, dated as of May 31, 2012, between KCP&L Greater Missouri Operations Company, as Originator, and GMO Receivables Company, as Buyer (Exhibit 10.2. to Form 10-Q for the quarter ended June 30, 2012).	Great Plains Energy
10.67	*	Receivables Sale Agreement, dated as of May 31, 2012, among GMO Receivables Company, as the Seller, KCP&L Greater Missouri Operations Company, as the Initial Collection Agent, The Bank of Tokyo-Mitsubishi, Ltd., New York Branch, as the Agent, and Victory Receivables Corporation (Exhibit 10.3 to Form 10-Q for the quarter ended June 30, 2012).	Great Plains Energy
10.68	*	First Amendment dated as of September 9, 2014, to the Receivables Sales Agreement dated as of May 31, 2012, among GMO Receivables Company, as the Seller, KCP&L Greater Missouri Operations Company, as the Initial Collection Agent, The Bank of Tokyo-Mitsubishi, Ltd., New York Branch, as the Agent and Victory Receivables Corporation, as the Purchaser (Exhibit 10.2 to Form 8-K filed on September 15, 2014).	Great Plains Energy
10.69	*	Second Amendment dated as of September 9, 2015, to the Receivables Sales Agreement dated as of May 31, 2012, among GMO Receivables Company, as the Seller, KCP&L Greater Missouri Operations Company, as the Initial Collection Agent, The Bank of Tokyo-Mitsubishi, Ltd., New York Branch, as the Agent and Victory Receivables Corporation, as the Purchaser (Exhibit 10.2 to Form 8-K filed on September 11, 2015).	Great Plains Energy
10.70	*	Third Amendment dated as of September 9, 2016, to the Receivables Sales Agreement dated as of May 31, 2012, among GMO Receivables Company, as the Seller, KCP&L Greater Missouri Operations Company, as the Initial Collection Agent, The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch, as the Agent and Victory Receivables Corporation, as the Purchaser (Exhibit 10.2 to Form 8-K filed September 13, 2016).	Great Plains Energy
10.71	*	Amendment dated as of September 8, 2017, to the Receivables Sales Agreement dated as of July 1, 2005, among Kansas City Power & Light Receivables Company, as the Seller, Kansas City Power & Light Company, as the Initial Collection Agent, The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch, as the Agent and Victory Receivables Corporation, as the Purchaser (Exhibit 10.1 to Form 8-K filed on September 11, 2017).	KCP&L

10.72	*	Fourth Amendment dated as of September 8, 2017, to the Receivables Sales Agreement dated as of May 31, 2012, among GMO Receivables Company, as the Seller, KCP&L Greater Missouri Operations Company, as the Initial Collection Agent, The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch, as the Agent and Victory Receivables Corporation, as the Purchaser (Exhibit 10.2 to Form 8-K filed on September 11, 2017).	Great Plains Energy
10.73	*	Iatan Unit 2 and Common Facilities Ownership Agreement, dated as of May 19, 2006, among Kansas City Power & Light Company, Aquila, Inc., The Empire District Electric Company, Kansas Electric Power Cooperative, Inc., and Missouri Joint Municipal Electric Utility Commission (Exhibit 10.2.a to Form 10-Q for the quarter ended June 30, 2006).	Great Plains Energy KCP&L
10.74	*	Joint Motion and Settlement Agreement dated as of February 26, 2008, among Great Plains Energy Incorporated, Kansas City Power & Light Company, the Kansas Corporation Commission Staff, the Citizens' Utility Ratepayers Board, Aquila, Inc. d/b/a Aquila Networks, Black Hills Corporation, and Black Hills/Kansas Gas Utility Company, LLC (Exhibit 10.1.7 to Form 10-Q for the quarter ended March 31, 2008).	Great Plains Energy KCP&L
10.75	*	Stipulation and Agreement dated April 24, 2009, among Kansas City Power & Light Company, Staff of the Missouri Public Service Commission, Office of Public Counsel, Praxair, Inc., Midwest Energy Users Association, U.S. Department of Energy and the U.S. Nuclear Security Administration, Ford Motor Company, Missouri Industrial Energy Consumers and Missouri Department of Natural Resources (Exhibit 10.1 to Form 8-K filed April 30, 2009).	Great Plains Energy KCP&L
10.76	*	Non-Unanimous Stipulation and Agreement dated May 22, 2009 among KCP&L Greater Missouri Operations Company, the Staff of the Missouri Public Service Commission, the Office of the Public Counsel, Missouri Department of Natural Resources and Dogwood Energy, LLC (Exhibit 10.1 to Form 8-K filed on May 27, 2009).	Great Plains Energy
10.77	*	Collaboration Agreement dated as of March 19, 2007, among Kansas City Power & Light Company, Sierra Club and Concerned Citizens of Platte County, Inc. (Exhibit 10.1 to Form 8-K filed on March 20, 2007).	Great Plains Energy KCP&L
10.78	*	Amendment to the Collaboration Agreement effective as of September 5, 2008 among Kansas City Power & Light Company, Sierra Club and Concerned Citizens of Platte County, Inc. (Exhibit 10.2.20 to Form 10-K for the year ended December 31, 2009).	Great Plains Energy KCP&L

10.79	*	Joint Operating Agreement between Kansas City Power & Light Company and Aquila, Inc., dated as of October 10, 2008 (Exhibit 10.2.2 to Form 10-Q for the quarter ended September 30, 2008).	Great Plains Energy KCP&L
12.1	*	Computation of Ratios of Earnings to Fixed Charges and Earnings to Combined Fixed Charges and Preferred Dividend Requirements (Exhibit 12.1 to Form 10-K for the year ended December 31, 2017).	Great Plains Energy
12.2	*	Computation of Ratio of Earnings to Fixed Charges (Exhibit 12.2 to Form 10-K for the year ended December 31, 2017).	KCP&L
21.1	*	List of Subsidiaries of Great Plains Energy Incorporated (Exhibit 21.1 to Form 10-K for the year ended December 31, 2017).	Great Plains Energy
23.1	*	Consent of Independent Registered Public Accounting Firm (Exhibit 23.1 to Form 10-K for the year ended December 31, 2017).	Great Plains Energy
23.2	*	Consent of Independent Registered Public Accounting Firm (Exhibit 23.2 to Form 10-K for the year ended December 31, 2017).	KCP&L
24.1	*	Powers of Attorney (Exhibit 24.1 to Form 10-K for the year ended December 31, 2017).	Great Plains Energy
24.2	*	Powers of Attorney (Exhibit 24.2 to Form 10-K for the year ended December 31, 2017).	KCP&L
31.1	*	Rule 13a-14(a)/15d-14(a) Certification of Terry Bassham (Exhibit 31.1 to Form 10-K for the year ended December 31, 2017).	Great Plains Energy
31.2	*	Rule 13a-14(a)/15d-14(a) Certification of Kevin E. Bryant (Exhibit 31.2 to Form 10-K for the year ended December 31, 2017).	Great Plains Energy
31.3	*	Rule 13a-14(a)/15d-14(a) Certification of Terry Bassham (Exhibit 31.3 to Form 10-K for the year ended December 31, 2017).	KCP&L
31.4	*	Rule 13a-14(a)/15d-14(a) Certification of Kevin E. Bryant (Exhibit 31.4 to Form 10-K for the year ended December 31, 2017).	KCP&L

31.5		Rule 13a-14(a)/15d-14(a) Certification of Terry Bassham.	Great Plains Energy
31.6		Rule 13a-14(a)/15d-14(a) Certification of Kevin E. Bryant.	Great Plains Energy
32.1	**	Section 1350 Certifications (Exhibit 32.1 to Form 10-K for the year ended December 31, 2017).	Great Plains Energy
32.2	**	Section 1350 Certifications (Exhibit 32.2 to Form 10-K for the year ended December 31, 2017).	KCP&L
101.INS	*	XBRL Instance Document (Exhibit 101.INS to Form 10-K for the year ended December 31, 2017).	Great Plains Energy KCP&L
101.SCH	*	XBRL Taxonomy Extension Schema Document (Exhibit 101.SCH to Form 10-K for the year ended December 31, 2017).	Great Plains Energy KCP&L
101.CAL	*	XBRL Taxonomy Extension Calculation Linkbase Document (Exhibit 101.CAL to Form 10-K for the year ended December 31, 2017).	Great Plains Energy KCP&L
101.DEF	*	XBRL Taxonomy Extension Definition Linkbase Document (Exhibit 101.DEF to Form 10-K for the year ended December 31, 2017).	Great Plains Energy KCP&L
101.LAB	*	XBRL Taxonomy Extension Labels Linkbase Document (Exhibit 101.LAB to Form 10-K for the year ended December 31, 2017).	Great Plains Energy KCP&L
101.PRE	*	XBRL Taxonomy Extension Presentation Linkbase Document (Exhibit 101.PRE to Form 10-K for the year ended December 31, 2017).	Great Plains Energy KCP&L

* Filed with the SEC as exhibits to prior SEC filings and are incorporated herein by reference and made a part hereof. The SEC filings and the exhibit number of the documents so filed, and incorporated herein by reference, are stated in parenthesis in the description of such exhibit.

** Furnished and shall not be deemed filed for the purpose of Section 18 of the Securities Exchange Act of 1934, as amended (the Exchange Act). Such document shall not be incorporated by reference into any registration statement or other document pursuant to the Exchange Act or the Securities Act of 1933, as amended, unless otherwise indicated in such registration statement or other document.

+ Indicates management contract or compensatory plan or arrangement.

Copies of any of the exhibits filed with the SEC in connection with this document may be obtained from the registrant upon written request. The registrants agree to furnish to the SEC upon request any instrument with respect to long-term debt as to which the total amount of securities authorized does not exceed 10% of total assets of such registrant and its subsidiaries on a consolidated basis.

SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

GREAT PLAINS ENERGY INCORPORATED

Date: April 26, 2018

By: /s/ Terry Bassham
Terry Bassham
Chairman, President and Chief Executive Officer

Exhibit 31.5

CERTIFICATIONS

I, Terry Bassham, certify that:

1. I have reviewed this annual report on Form 10-K/A of Great Plains Energy Incorporated; and

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report.

Date: April 26, 2018

/s/ Terry Bassham

Terry Bassham
Chairman, Chief Executive Officer and President

Exhibit 31.6

CERTIFICATIONS

I, Kevin E. Bryant, certify that:

1. I have reviewed this annual report on Form 10-K/A of Great Plains Energy Incorporated; and

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report.

Date: April 26, 2018

/s/Kevin E. Bryant

Kevin E. Bryant
Senior Vice President - Finance and Strategy and
Chief Financial Officer

SECTION 14

ADDITIONAL EVIDENCE

SECTION 15
ADDITIONAL EVIDENCE

SECTION 16
FINANCIAL STATEMENTS

Please refer to Item 8, Consolidated Financial Statements, of Form 10-K contained in Section 13 for the latest audited financial statements and accompanying notes.

SECTION 17
DATA BY TARIFF SCHEDULE

Kansas City Power & Light Company
Retail Revenue Summary Kansas
Information Filed in Accordance with K.A.R. 82 1 231
Test Year Ending September 30, 2017

Line No.	Class/ Rate Code	Description	Average Number of WN-EE-Current Customers	WN-EE-Current kWh	WN-EE-Current Revenue	Average Price per kWh	Proposed Revenue	Proposed Price per kWh **	Proposed Revenue Increase	Proposed Percent Increase	Average Monthly Increase per Customer	Proposed Increase ($) per kWh **	Average Monthly kWh Usage per Customer
	( )	(ii)	(iii)	(iv)	(v - v i)	(vii)	(ix)	(x)	(xi)	(xii)			
1	**Residential**												
2	2RO1A	Res Other Use - 1 Mtr	143	486,311	$ 75,884	$ 0.15604	$ 82,281	$ 0.16919	$ 6,396	8.43%	$ 3.74	$ 0.01315	284
3	2RS1A/2RSDA	Res Std (or Res w th Water Heating)/Master Metered/3 phase AC Demand - 1 Meter	155,981	1,886,752,600	$ 203,739,517	$ 0.10798	$ 220,907,097	$ 0.11708	$ 17,167,580	8.43%	$ 9.17	$ 0.00910	1,008
4	2RS2A/2RS3A/2RW7A	Res Std with Space Htg (or with Wtr Htg & Space Htg)- 2 Mtrs (submtr/ inefed)	12,283	182,790,464	$ 16,732,102	$ 0.09154	$ 18,142,600	$ 0.09925	$ 1,410,498	8.43%	$ 9.57	$ 0.00772	1,240
5	2RS6A/2RW6A	Res Std with Space Htg (or with Wtr Htg & Space Htg)/Res A l Elec Apartments - Master Mtrd & b lled based on Nbr of un ts - 1 Mtr	55,643	777,072,549	$ 74,804,476	$ 0.09626	$ 81,110,256	$ 0.10438	$ 6,305,780	8.43%	$ 9.44	$ 0.00811	1,164
6	2TE1A	Res Time-of-Day Energy - 1 Mtr	50	695,011	$ 71,499	$ 0.10287	$ 77,526	$ 0.11155	$ 6,027	8.43%	$ 10.13	$ 0.00867	1,168
7	**Small General Service**												
8	2SGAE/2SGAH	Sma l Gen Serv, Genly Avail, All-Electric, Urban Comm/Mfg-Secondary	1,187	23,980,898	$ 2,466,631	$ 0.10286	$ 2,551,549	$ 0.10286	$ 84,918	3.44%	$ 5.96	$ -	1,684
9	2SGHE/2SGHH	Sma l Gen Serv, Genly Avail, Sep Mtr Heat, Urban Comm/Mfg-Secondary	393	9,331,791	$ 1,026,266	$ 0.10998	$ 1,091,499	$ 0.10998	$ 65,233	6.36%	$ 13.84	$ -	1,980
10	2SGSE/2SGSH/2SUSE/2SUSH	Sma l Gen Serv, Genly Avail, Std, Urban Comm/Mfg/Unmetered Sv-Secondary	21,634	344,165,712	$ 40,225,893	$ 0.11688	$ 41,316,925	$ 0.11688	$ 1,091,032	2.71%	$ 4.20	$ -	1,326
11	2SGSF/2SGSG	Sma l Gen Serv, Genly Avail, Std, Urban Comm/Mfg-Primary	7	215,585	$ 22,956	$ 0.10648	$ 23,647	$ 0.10648	$ 691	3.01%	$ 8.04	$ -	2,507
12	2SGAF/2SGAG	Sma l Gen Serv, Genly Avail, All-Electric, Urban Comm/Mfg-Primary	5	1,596,440	$ 216,450	$ 0.13558	$ 227,718	$ 0.13558	$ 11,268	5.21%	$ 190.98	$ -	27,058
13	**Medium General Service**												
14	2MGAE/2MGAH	Medium Gen Serv, Genly Avail, All-Electric, Urban Comm/Mfg-Secondary	439	119,416,814	$ 9,155,344	$ 0.07667	$ 9,467,920	$ 0.07667	$ 312,576	3.41%	$ 59.28	$ -	22,647
15	2MGAF/2MGAG	Medium Gen Serv, Genly Avail, All-Electric, Urban Comm-Primary	6	3,039,553	$ 335,096	$ 0.11025	$ 351,857	$ 0.11025	$ 16,761	5.00%	$ 250.16	$ -	45,366
16	2MGHE/2MGHH	Medium Gen Serv, Genly Avail, Sep Mtr Heat, Urban Comm/Mfg-Secondary	97	16,190,573	$ 1,443,066	$ 0.08913	$ 1,508,711	$ 0.08913	$ 65,645	4.55%	$ 56.35	$ -	13,897
17	2MGSE/2MGSH	Medium Gen Serv, Genly Avail, Std, Urban Comm/Mfg-Secondary	3,424	618,924,599	$ 58,291,865	$ 0.09418	$ 59,870,608	$ 0.09418	$ 1,578,743	2.71%	$ 38.43	$ -	15,064
18	2MGSF/2MGSG	Medium Gen Serv, Genly Avail, Std, Urban Comm/Mfg-Primary	4	750,737	$ 60,539	$ 0.08064	$ 61,989	$ 0.08064	$ 1,450	2.39%	$ 30.21	$ -	15,640
19	**Large General Service**												
20	2LGAE/2LGAH	Large Gen Serv, Genly Avail, All-Electric, Urban Comm/Mfg-Secondary	304	675,050,693	$ 43,320,884	$ 0.06417	$ 44,655,012	$ 0.06417	$ 1,334,128	3.08%	$ 365.61	$ -	184,996
21	2LGAF/2LGAG	Large Gen Serv, Genly Avail, All-Electric, Urban Comm-Primary	3	46,163,227	$ 2,326,077	$ 0.05039	$ 2,381,335	$ 0.05039	$ 55,258	2.38%	$ 1,416.88	$ -	1,183,672
22	2LGHE/2LGHH	Large Gen Serv, Genly Avail, Sep Mtr Heat, Urban Comm/MFG-Secondary	55	76,788,344	$ 5,341,530	$ 0.06956	$ 5,570,670	$ 0.06956	$ 229,140	4.29%	$ 348.77	$ -	116,877
23	2LGSE/2LGSH	Large Gen Serv, Genly Avail, Std, Urban Comm/Mfg-Secondary	741	1,195,324,578	$ 88,455,225	$ 0.07400	$ 90,902,026	$ 0.07400	$ 2,446,801	2.77%	$ 275.35	$ -	134,518
24	2LGSF/2LGSG	Large Gen Serv, Genly Avail, Std, Urban Comm/Mfg-Primary	40	251,099,373	$ 16,150,644	$ 0.06432	$ 16,552,136	$ 0.06432	$ 401,492	2.49%	$ 832.97	$ -	520,953
25	2LGSV/2LGSU	Large Gen Serv, Genly Avail, Std, Urban Mfg-Substation	1	26,069,720	$ 1,452,064	$ 0.05570	$ 1,493,348	$ 0.05570	$ 41,284	2.84%	$ 3,440.34	$ -	2,172,477
26	2LGSW/2LGSZ	Large Gen Serv, Genly Avail, Std, Urban Comm/Mfg-Transmission	1	95,689,018	$ 5,356,277	$ 0.05598	$ 5,477,883	$ 0.05598	$ 121,606	2.27%	$ 10,133.82	$ -	7,974,085
27	**Other (Lighting and Traffic Signals)**												
28	2ALDA	KS Residential Area Lights	1,830	1,016,787	$ 363,795	$ 0.35779	$ 374,166	$ 0.36799	$ 10,371	2.85%	$ 0.47	$ 0.01020	46
29	2ALDE	KS Commercial Area Lights	719	1,978,664	$ 538,932	$ 0.27237	$ 554,296	$ 0.28014	$ 15,364	2.85%	$ 1.78	$ 0.00776	229
30	2TSLM	KS Traffic Signal	12	2,464,312	$ 1,444,979	$ 0.58636	$ 1,486,172	$ 0.60308	$ 41,193	2.85%	$ 286.06	$ 0.01672	17,113
31	MLC, MLM, MLS	KS Street Lighting Public	66	5,635,942	$ 1,961,072	$ 0.34796	$ 2,016,978	$ 0.35788	$ 55,905	2.85%	$ 70.32	$ 0.00992	7,089
32	OPL	KS Off Peak Lighting Service	1,576	42,876,719	$ 2,482,909	$ 0.05791	$ 2,553,690	$ 0.05956	$ 70,782	2.85%	$ 3.74	$ 0.00165	2,268
33	2MLLL	KS StreetLight-MuniLED	2	40,758	$ 35,781	$ 0.87787	$ 36,801	$ 0.90290	$ 1,020	2.85%	$ 40.80	$ 0.02503	1,630
34	**Subtotal Kansas Retail Billed**		**256,645**	**6,405,607,774**	**$ 577,897,754**	**$ 0.09022**	**$ 610,846,694**	**$ 0.09536**	**$ 32,948,941**	**5.70%**	**$ 10.70**	**$ 0.00514**	**2,080**
35	Area Lights not included in total customer count		(2,549) *										
36	**Total Kansas Retail Billed**		**254,096**	**6,405,607,774**	**$ 577,897,754**	**$ 0.09022**	**$ 610,846,694**	**$ 0.09536**	**$ 32,948,941**	**5.70%**	**$ 10.81**	**$ 0.00514**	**2,101**

**Area lights not included in total customer count*

*** No revenue increase was applied to the energy rates for Small GS Med um GS and Large GS.*

SECTION 18

PROPOSED RATE CHANGE SCHEDULES/ RULES AND REGULATIONS

LIST OF TARIFFS TO CHANGE

Rate Tariffs

Schedule TOC-1, Sheet 1
Schedule TOC-1, Sheet 2
Schedule TOC-1, Sheet 3
Schedule TOC-1, Sheet 4
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Schedule 11, Sheet 2
Schedule 11, Sheet 3
Schedule 12, Sheet 1
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Schedule 80, Sheet 5
Schedule 82, Sheet 2

Rules and Regulations Tariffs

Schedule 1.07, Sheet 7
Schedule 1.84, Sheet 84
Schedule 1.85, Sheet 85

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Rate Schedule Title	Rate Schedule Designation	Sheet Number
Residential		
Residential Service	R	11
Residential Other Use	ROU	12
Residential Time of Day Service (Frozen)	RTOD	16
Residential Time of Use Service Pilot	RTOU	17
Residential Demand Service Pilot	RD	18
Residential Demand Service plus Time of Use Pilot	RDTOU	19
Demand Service for Residential Distributed Generation	RDG	23
Commercial & Industrial		
Small General Service	SGS	31
Small General Service – Space Heating	SGA	44
Medium General Service	MGS	32
Medium General Service – Space Heating	MGA	45
Large General Service	LGS	33
Large General Service Off-Peak Rider	LGS-2	34
Large General Service – Space Heating	LGA	46
Lighting		
Off-Peak Lighting Service	LS	70
Private Unmetered Protective Lighting Service (Frozen)	AL	71
Private Unmetered LED Lighting Service	PL	72
Municipal Street Lighting Service	ML	73
Municipal Ornamental Street Lighting Service	MOL	69
Municipal Traffic Control Signal Service	TR	74
Municipal Street Lighting – LED Pilot Program	ML-LED	82
Customer Generation and Renewables		
Standby Service Rider	SSR	64
Renewable Energy Rider	RER	65
Solar Subscription Pilot Rider	SSP	66
Net Metering	NM	67
Parallel Generation Contract Service	PG	68

THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE TOC-1

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule TOC-1 Sheet 2

Rate Areas No. 2 & 4
(Territory to which schedule is applicable)

which was filed September 10, 2015

No supplement or separate understanding shall modify the tariff as shown hereon.

Sheet 2 of 4 Sheets

TABLE OF CONTENTS
OF RATES FOR STATE OF KANSAS

Rate Schedule Title	Rate Schedule Designation	Sheet Number
<u>Energy Efficiency, Demand Response, & End Use</u>		
Income Eligible Weatherization	IEW	6
Air Conditioner Cycling – Programmable Thermostat Program	PT	7
Building Operator Certification Program	BOC	8
Energy Audit & Energy Saving Measures Rider (Frozen)	ER	9
Cool Homes Program (Frozen)	CHP	13
ENERGY STAR® New Homes (Frozen)	NH	14
Public Electric Vehicle Charging Station Service	CCN	20
Residential Home Energy Report Pilot Program	RHER	21
Residential Smart Thermostat Pilot Program	RSTP	22
Demand Response Incentive Rider	DR	76
<u>Riders and Surcharges</u>		
Tax Adjustment	TA	1
Energy Cost Adjustment	ECA	2
Additional Equipment Rental Charge	AE	3
Municipal Underground Service Rider	UG	5
Property Tax Surcharge	PTS	10
Energy Efficiency Rider	EE	15
Economic Development Rider	EDR	75
Thermal Storage Rider	TS	77
Voluntary Load Reduction Rider	VLR	78
Transmission Delivery Charge	TDC	83

Issued: May 1, 2018
Month Day Year

Effective:
Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE TOC-1

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule TOC-1 Sheet 3

Rate Areas No. 2 & 4
(Territory to which schedule is applicable)

which was filed September 10, 2015

No supplement or separate understanding
shall modify the tariff as shown hereon.

TABLE OF CONTENTS
OF RATES FOR STATE OF KANSAS

Sheet Number	Rate Schedule Title	Rate Schedule Designation
1	Tax Adjustment	TA
2	Energy Cost Adjustment	ECA
3	Additional Equipment Rental Charge	AE
5	Municipal Underground Service Rider	UG
6	Income Eligible Weatherization	IEW
7	Air Conditioner Cycling – Programmable Thermostat Program	EO
8	Building Operator Certification Program	BOC
9	Energy Audit & Energy Savings Measure Rider (Frozen)	ER
10	Property Tax Surcharge	PTS
11	Residential Service	R
12	Residential Other Use	ROU
13	Cool Homes Program (Frozen)	CHP
14	ENERGY STAR® New Homes (Frozen)	NH
15	Energy Efficiency Rider	EE
16	Residential Time of Day Service (Frozen)	RTOD
17	Residential Time of Use Service Pilot	RTOU
18	Residential Demand Service Pilot	RD
19	Residential Demand Service plus Time of Use Pilot	RDTOU
20	Public Electric Vehicle Charging Station Service	CCN
21	Residential Home Energy Report Pilot Program	RHER
22	Residential Smart Thermostat Pilot Program	RSTP
23	Demand Service for Residential Distributed Generation	RDG
31	Small General Service	SGS
32	Medium General Service	MGS
33	Large General Service	LGS
34	Large General Service Off-Peak Rider	LGS-2
44	Small General Service – Space Heating	SGA
45	Medium General Service – Space Heating	MGA
46	Large General Service – Space Heating	LGA
64	Standby Service Rider	SSR
65	Renewable Energy Rider	RER
66	Solar Subscription Pilot Rider	SSP
67	Net Metering	NM
68	Parallel Generation Contract Service	PG
31	Small General Service	SGS

Issued: May 1, 2018
Month Day Year

Effective:
Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE TOC-1

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule ______ Sheet ______

Rate Areas No. 2 & 4
(Territory to which schedule is applicable)

which was filed ______

No supplement or separate understanding shall modify the tariff as shown hereon.

Sheet 4 of 4 Sheets

TABLE OF CONTENTS
OF RATES FOR STATE OF KANSAS

Sheet Number	Rate Schedule Title	Rate Schedule Designation
69	Municipal Ornamental Street Lighting Service	MOL
70	Off-Peak Lighting Service	LS
71	Private Unmetered Protective Lighting Service (Frozen)	AL
72	Private Unmetered LED Lighting Service	PL
73	Municipal Street Lighting Service	ML
74	Municipal Traffic Control Signal Service	TR
75	Economic Development Rider	EDR
76	Demand Response Incentive Rider	DR
77	Thermal Storage Rider	TS
78	Voluntary Load Reduction Rider	VLR
82	Municipal Street Lighting – LED Pilot Program	ML-LED
83	Transmission Delivery Charge	TDC

Issued: May 1, 2018
Month Day Year

Effective: ______
Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

ENERGY COST ADJUSTMENT
Schedule ECA

APPLICABILITY:
This Energy Cost Adjustment (ECA) Schedule shall be applicable to all Kansas Retail Rate Schedules for KCPL.

BASIS:
Energy costs will be measured and applied to a customer's bill using an ECA factor. The ECA factor is applied on a kilowatt-hour basis ($/kWh). Retail customer charges for energy costs are determined by multiplying the kilowatt-hours of electricity during any calendar month by the corresponding ECA factor for that calendar month.

ENERGY COST ADJUSTMENT:
Prior to January 1 of each ECA year, an ECA factor (ECA_P) will be calculated for each calendar month of the ECA year as follows:

$$ECA_P = \frac{((F_P + P_P + E_P) - BPR_P)}{S_P} - \frac{OSSM_K}{S_K} - \frac{TRUE_A}{S_{TRUE}}$$

Where:

F_P = Projected cost of nuclear and fossil fuel to be consumed for the generation of electricity during the month in which the ECA is in effect for all KCPL Retail, Requirements Sales for Resale, and Bulk Power Sales customers not included in OSSM, to be recorded in Account 501, Account 518 and Account 547, excluding any KCPL internal labor cost.

P_P = Projected cost of purchased power during the month in which the ECA is in effect for all KCPL Retail, Requirements Sales for Resale, and Bulk Power Sales customers not included in OSSM, to be recorded in Account 555, and KCPL's projected charges or credits incurred due to participation in markets associated with Regional Transmission Organizations (RTOs) excluding amounts associated with portions of purchased power agreements dedicated to specific customers under the Renewable Energy Rider tariff.

E_P = Projected cost of emission allowances during the month in which the ECA is in effect for all KCPL Retail, Requirements Sales for Resale, and Bulk Power Sales customers not included in OSSM, to be recorded In Account 509.

BPR_P = Projected Revenue from asset-based Bulk Power Sales customers not included in OSSM.

S_P = Projected kWhs to be delivered to all KCPL Retail and Requirements Sales for Resale customers during the month in which the ECA is in effect.

OSSM = Projected annual asset-based Off-System Sales Margin from Bulk Power Sales at the median for the effective ECA year, but excluding: (1) amounts associated with portions of purchased power agreements dedicated to specific customers under the Renewable Energy Rider tariff; and (2) amounts associated with generation assets dedicated to specific customers under the Renewable Energy Rider tariff.

$OSSM_K$ = The projected annual asset-based Off-System Sales Margin from Bulk Power Sales at the median for the effective ECA, but excluding: (1) amounts associated with portions of purchased power agreements dedicated to specific customers under the Renewable Energy Rider tariff; and (2) amounts associated with generation assets dedicated to specific customers under the Renewable Energy Rider tariff year multiplied by the projected Unused Energy (UE1) Allocator for Kansas.

S_K = Projected annual kWhs to be delivered to all Kansas Retail customers during the effective ECA year.

S_{TRUE} = Projected kWhs for Kansas Retail customers for the twelve-month period beginning in April of the year following the ECA year.

ENERGY COST ADJUSTMENT
Schedule ECA

$TRUE_A$ = The annual true-up amount for an ECA year, to be calculated by March 1 of the year following the ECA year and to be applied for a twelve-month period beginning April 1 of the year following the ECA year. The true-up amount will reflect any difference between the total ECA revenue for the Retail sales during the ECA year and the actual costs incurred to achieve those Retail sales less the credits applied for Off-System Sales Revenue for the ECA year. Such true-up amount may be positive or negative. Any remaining balances from prior true-up periods will be added.

$$TRUE_A = ECAREV_A - \left[((F_A + P_A + E_A - BPR_A) - NABPC_A) \times \frac{S_{AK}}{S_{AT}}\right] + OSSM_A + TRUE_{PRIOR}$$

Where:

$ECAREV_A$ = Actual ECA revenue for Kansas Retail sales during the ECA year.

F_A = Actual total company cost of nuclear and fossil fuel consumed for the generation of electricity for the ECA year recorded in Account 501, Account 518 and Account 547, excluding any internal KCPL labor cost and all costs associated with $OSSM_A$.

P_A = Actual total company cost of purchased power incurred during the ECA year recorded in Account 555, and KCPL's actual charges or credits incurred due to participation in markets associated with Regional Transmission Organizations (RTOs) less all costs associated with $OSSM_A$ excluding amounts associated with portions of purchased power agreements dedicated to specific customers under the Renewable Energy Rider tariff.

E_A = Actual total company emission allowance costs incurred during the ECA year recorded in Account 509 less all costs associated with $OSSM_A$.

BPR_A = Actual Revenue from asset-based Bulk Power Sales customers not included in $OSSM_A$, but excluding: (1) amounts associated with portions of purchased power agreements dedicated to specific customers under the Renewable Energy Rider tariff; and (2) amounts associated with generation assets dedicated to specific customers under the Renewable Energy Rider tariff.

$NABPC_A$ = Actual total company cost for non-asset-based sales to Bulk Power customers during the ECA year, as reflected in P_A,.

$OSSM_A$ = Actual total company asset-based Off-System Sales Margin from Bulk Power Sales for the ECA but excluding: (1) amounts associated with portions of purchased power agreements dedicated to specific customers under the Renewable Energy Rider tariff; and (2) amounts associated with generation assets dedicated to specific customers under the Renewable Energy Rider tariff year multiplied by the actual Unused Energy (UE1) Allocator for Kansas.

S_{AK} = Actual kWhs delivered to KCPL's Kansas Retail customers during the ECA year.

S_{AT} = Actual kWhs delivered to all KCPL Retail and Requirements Sales for Resale customers during the ECA year.

$TRUE_{PRIOR}$ = Remaining true-up amounts from previous ECA years (positive or negative).

RESIDENTIAL SERVICE
Schedule R (Continued)

RATE:

Single-phase kWh and three-phase kWh will be cumulated for billing under this schedule.

1. RESIDENTIAL GENERAL USE – ONE METER: 2RS1A, 2RSDA

For general residential use including electric water heating equipment not connected through a separately metered circuit, the kWh shall be billed as follows:

A. Customer Charge (Per Month) $15.18

		Summer Season	Winter Season
B.	Energy Charge (Per kWh):		
	First 1000 kWh per month	$0.11657	$0.08999
	Over 1000 kWh per month	$0.11657	$0.08999

2. RESIDENTIAL GENERAL USE AND SPACE HEAT - ONE METER: 2RS6A, 2RW6A

When the customer has electric space heating equipment for the residence and the equipment is of a size and design approved by the Company and not connected through a separately metered circuit, the kWh shall be billed as follows (customer may also have electric water heating equipment, of a size and design approved by the Company, under this option):

A. Customer Charge (Per Month) $15.18

		Summer Season	Winter Season
B.	Energy Charge (Per kWh)		
	First 1000 kWh per month	$0.11657	$0.08104
	Over 1000 kWh per month	$0.11657	$0.07074

RESIDENTIAL SERVICE
Schedule R (Continued)

3. RESIDENTIAL GENERAL USE AND SPACE HEAT - 2 METERS: 2RS2A, 2RS3A, 2RW7A

When the customer has electric space heating equipment for the residence and the equipment is of a size and design approved by the Company and connected through a separately metered circuit or may also have electric water heating equipment connected through the same separately metered circuit, the kWh used shall be billed as follows. This option of separately metered space heating is limited to premises connected prior to January 1, 2007.

A. Customer Charge (Per Month) $15.18

		Summer Season	Winter Season
B.	Energy Charge for Usage on General Use Meter (Per kWh, Per Month)		
	First 1000 kWh per month	$0.11657	$0.08104
	Over 1000 kWh per month	$0.11657	$0.07077
C.	Separately metered space heat rate:		
	For all kWh (Per kWh)	$0.11657	$0.07074

4. When a customer has electric space heating equipment and electric water heating equipment of a size and design approved by the Company connected through a separately metered circuit, the kWh used shall be billed on Rate D above. This option of connecting water heating equipment on the separately metered circuit is limited to customers being billed under this rate option prior to March 1, 1999.

MINIMUM:

Minimum Monthly Bill:

1. Customer Charge; plus
2. Any additional charges for line extensions, if applicable.

RESIDENTIAL OTHER USE
Schedule ROU

AVAILABILITY:

This rate schedule applies to residential customers who do not qualify under any other residential rate. Customers qualifying for this rate will generally be those with well pumps, barns, machine sheds, detached garages, home workshops, or recreational vehicles whose meter is not connected to a single or multiple occupancy dwelling unit. This rate schedule cannot be used for any commercial or industrial customer.

RATE: 2RO1A

		Summer Season	Winter Season
1.	Customer Charge (per month)	$15.18	$15.18
2.	Energy Charge (per kWh)		
	All Energy	$0.13609	$0.10693

MINIMUM:

Minimum Monthly Bill:

1. Customer Charge; plus
2. Any additional charges for line extensions, if applicable; plus

SUMMER AND WINTER SEASONS:

The Summer Season is four consecutive months, beginning and effective May 16 and ending September 15, inclusive. The Winter Season is eight consecutive months, beginning and effective September 16 and ending May 15. Customer bills for meter reading periods including one or more days in both seasons will reflect the number of days in each season.

ADJUSTMENTS AND SURCHARGES:

The rates hereunder are subject to adjustment as provided in the following schedules:

- Energy Cost Adjustment (ECA)
- Energy Efficiency Rider (EER)
- Property Tax Surcharge (PTS)
- Tax Adjustment (TA)
- Transmission Delivery Charge (TDC)

REGULATIONS:

Subject to Rules and Regulations filed with the State Regulatory Commission.

Issued: May 1, 2018
Month Day Year

Effective:
Month Day Year

By: /s/ Darrin R. Ives, Vice President
Title

ENERGY EFFICIENCY RIDER
Schedule EE

APPLICABILITY:

This Energy Efficiency (EE) Rider (Schedule EE) shall be applicable to all non-lighting Kansas Retail Rate Schedules for KCPL.

PURPOSE:

This EE Rider is designed to recover all costs associated with the following Commission-approved Income-Eligible, Energy Efficiency and Demand Response schedules: (1) IEW; (2) PT; (3) BOC; (4) ER; (5) CHP; (6) NH; (7) RHER; (8) RSTP; and (9) DRI. KCPL will file a new EE Rider no later than March 31 of each year to recover EE Program costs incurred during the prior calendar year for recovery over the following July through June period.

BASIS:

Program Costs will be recovered using an EE factor applied to each customer's bill. The EE factor will be applied to the customer's usage on a kilowatt-hour basis ($/kWh). Retail customer charges for EE Program Costs are determined by multiplying the kilowatt-hours of electricity billed by the corresponding EE factor. The customer charges associated with this EE Rider will be identified and shown as a separate line on the customer's bill.

ENERGY EFFICIENCY RIDER AMOUNT CALCULATION:

A separate EE factor will be calculated for each customer class based upon the demand allocator and total kWh for each class. The EE factor (EEF) for each customer class will be calculated to recover the Program Costs for approved EE Programs from the specified period plus any applicable true up amount from the prior period by applying a class Demand Allocator and then dividing by the total kilowatt-hours (kWh) for that class as follows:

$$EEF_{(class)} = \frac{(EEC_n + TRUE_{n-1}) \times DA_{(class)}}{KWH_{n\ (class)}}$$

Where:

EEC_n = All actual costs associated with Commission-approved EE Programs incurred during the applicable time-period (n). These costs are recorded in a deferred regulatory asset account established to accumulate the Kansas jurisdictional costs of all EE Programs.

THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 15

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 15 Sheet 2

Rate Areas No 2 & 4
(Territory to which schedule is applicable)

which was filed March 29, 2018

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 2 of 2 Sheets

ENERGY EFFICIENCY RIDER
Schedule EE (Continued)

Commented [MT1]: The proposed changes are based off of the version of Schedule 15 Sheet 2 currently filed within Docket: 18-KCPE-420-TAR

ENERGY EFFICIENCY RIDER AMOUNT CALCULATION: (Continued)

$TRUE_{n-1}$ = The annual true-up amount for an EE Rider year, to be determined prior to filing the next EE Rider and to be applied to the subsequent EE factor calculation. The true-up amount will reflect any difference between the total EE revenue collected and the actual costs (EEC_n) for the previous applicable time-period (n-1). Such true-up amount may be positive or negative. The true-up amount used to calculate the EEF for the first EE Rider equals zero.

$DA_{(class)}$ = The demand allocator for the applicable non-lighting classes. This demand allocator shall be based on the 12-CP allocator utilized by the Company for its Class Cost of Service Study in the most recent Kansas retail rate case.

$KWH_{n\ (class)}$ = The actual kWh electric sales for the Kansas jurisdiction for the applicable time-period (n) of the Class Cost of Service Study for the applicable class.

TERM:

This EE Rider shall remain in effect until such time the Commission-approved amount is recovered. In the event the Commission rules on, or a law is passed regarding treatment of such expenses, then KCPL shall have the right to file for Commission approval of a compliant recovery methodology to replace or revise this EE Rider. KCPL shall have the right to continue recovery under this EE Rider until such time a replacement methodology is approved and implemented or all Commission-approved amounts are recovered.

NOTES TO THE TARIFF:

1. The references to Accounts within the EE tariff are as defined in the FERC uniform system of accounts.

2. The EEC factor will be expressed in dollars per kilowatt-hour (kWh) rounded to five decimal places.

EE FACTORS FOR JULY 1, 2018 THROUGH JUNE 30, 2019 USAGE:

1.	Residential Service	$0.00000/kWh
2.	Small General Service	$0.00000/kWh
3.	Medium General Service	$0.00000/kWh
4.	Large General Service	$0.00000/kWh

Issued: May 1, 2018
Month Day Year

Effective:
Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

RESIDENTIAL TIME OF DAY SERVICE (FROZEN)
Schedule RTOD

AVAILABILITY:

For electric service to a single-occupancy private residence:

Single-phase electric service through one meter for ordinary domestic use for the first 500 new or existing customers who request to be served under this schedule. This limit may be extended upon prior consent of the Company depending upon the availability and installation of metering equipment.

Temporary or seasonal service will not be supplied under this schedule.

This schedule not available after October 1, 2015.

RATE: 2TE1A

Single-phase kWh will be cumulated for billing under this schedule.

1. Customer Charge (per customer per month): $21.69

2. Energy Charge (per kWh):

Summer Season:	Winter Season:
On-Peak Hours $0.19106	$0.08354
Off-Peak Hours $0.07991	

RESIDENTIAL TIME OF DAY SERVICE (FROZEN)
Schedule RTOD (Continued)

MINIMUM:

Minimum Monthly Bill:

1. Customer charge; plus
2. Any additional charges for line extensions, if applicable.

WINTER SEASON:

Eight consecutive months, spanning the period October 1 of one year to May 31 of the next year.

SUMMER SEASON:

Four consecutive months, spanning the period June 1 to September 30 each year.

SUMMER ON-PEAK AND OFF-PEAK PERIODS:

On-peak hours are defined to be the hours between 1 p.m. and 7 p.m., Monday through Friday, excluding week-day holidays during the Summer Season. Off-Peak hours are defined to be all other hours during the Summer Season. Week-day holidays are Independence Day and Labor Day.

ADJUSTMENTS AND SURCHARGES:

The rates hereunder are subject to adjustment as provided in the following schedules:

- Energy Cost Adjustment (ECA)
- Energy Efficiency Rider (EER)
- Property Tax Surcharge (PTS)
- Tax Adjustment (TA)
- Transmission Delivery Charge (TDC)

REGULATIONS:

Subject to Rules and Regulations filed with the State Regulatory Commission.

RESIDENTIAL TIME OF USE PILOT
Schedule RTOU

AVAILABILITY:

Available to single metered Residential customers receiving AMI-metered secondary electric service to a single occupancy private residence or individually metered living units in multiple occupancy residential buildings.

Not available to Customers that own and operate generation connected in parallel with the Company's electric system, or that receive service under Net Metering tariff (Schedule NM). Not available for Temporary, Seasonal, Three phase Standby, Supplemental, Resale or single metered multi-occupancy Residential Service.

APPLICABILITY:

This Pilot shall be available as an option to customers otherwise served under the Company's Residential Service (Schedule R) to encourage customers to shift consumption from higher cost time periods to lower-cost time periods.

This Pilot is limited to a maximum of one thousand (1,000) Residential customers, unless otherwise requested by the Company to be increased and such an increase in participation is approved by the State Regulatory Commission.

Any Customer who has exited the program, has been disconnected for non-payment, or is on a pay agreement may not be allowed to participate in this pilot at the Company's discretion.

Service shall be provided for a fixed term of not less than one (1) year, and for such time thereafter until terminated by either party via (30) day written notice.

Participation in this pilot is contingent upon approval of this rate and adequate recovery of all costs (including marketing, customer education, and administrative costs) and lost margins associated with the pilot rate by the State Regulatory Commission. These rates may be packaged with approved Demand Side Management Pilot Programs where program costs are recovered through the Energy Efficiency Rider (Schedule EE).

RESIDENTIAL TIME OF USE PILOT
Schedule RTOU (Continued)

RATE: RTOU2

		Summer Season	Winter Season
1.	Customer Charge (Per month)	$15.18	
2.	Energy Charge (Per kWh)		
	Peak	$0.28061	$0.20929
	Off-Peak	$0.09354	$0.08202
	Super Off-Peak	$0.04677	$0.03455

PRICING PERIODS:

Pricing periods are established in Central Standard Time year annually, and by season, for weekdays and weekends. The hours of the pricing periods for each season are as follows:

On-Peak:	4pm-8pm
Off-Peak:	6am-4pm; 8pm-12am
Super Off-Peak:	12am-6am

MINIMUM:

Minimum Monthly Bill:

1. Customer Charge; plus
2. Any additional charges for line extensions, if applicable.

SUMMER AND WINTER SEASONS:

The Summer Season is four consecutive months, beginning and effective May 16 and ending September 15, inclusive. The Winter Season is eight consecutive months, beginning and effective September 16 and ending May 15. Customer bills for meter reading periods including one or more days in both seasons will reflect the number of days in each season.

RESIDENTIAL TIME OF USE PILOT
Schedule RTOU (Continued)

ADJUSTMENTS AND SURCHARGES:

The rates hereunder are subject to adjustment as provided in the following schedules:

- Energy Cost Adjustment (ECA)
- Energy Efficiency Rider (EER)
- Property Tax Surcharge (PTS)
- Tax Adjustment (TA)
- Transmission Delivery Charge (TDC)

REGULATIONS:

Subject to Rules and Regulations filed with the State Regulatory Commission.

RESIDENTIAL DEMAND SERVICE PILOT
Schedule RD

AVAILABILITY:

Available to single-metered Residential customers receiving AMI-metered secondary electric service to a single-occupancy private residence or individually AMI-metered living units in multiple occupancy residential buildings.

Not available to Customers that own and operate generation connected in parallel with the Company's electric system that do not receive service under Net Metering tariff (Schedule NM).

Not available for Temporary, Seasonal, Three phase, Standby, Supplemental, or Resale or single metered multi-occupancy Residential Service.

APPLICABILITY:

This Residential Demand Service Pilot shall be available as an option to customers otherwise served under the Company's Residential Service (Schedule R) to encourage customers to manage their demand.

This Pilot is limited to a maximum of one thousand (1,000) Residential customers, unless otherwise requested by the Company to be increased and such an increase in participation is approved by the State Regulatory Commission.

Any Customer who exits the program, has been disconnected for non-payment, or is on a pay agreement may not be allowed to participate in this pilot at the Company's discretion.

Service shall be provided for a fixed term of not less than one (1) year and for such time thereafter until terminated by either party via thirty (30) day written notice.

Participation in this pilot is contingent upon approval of this rate and adequate recovery of all costs (including marketing, customer education, and administrative costs) and lost margins associated with the pilot rate by the State Regulatory Commission. These rates may be packaged with approved Demand Side Management Pilot Programs where program costs are recovered through the Energy Efficiency Rider (Schedule EE).

RESIDENTIAL DEMAND SERVICE PILOT
Schedule RD (Continued)

RATE: 2RD1A

		Summer Season	Winter Season
1.	Customer Charge (Per month)	$15.18	
2.	Demand Charge Per KW of Billing Demand per month	$14.000	$11.500
3.	Energy Charge (Per kWh) All Energy	$0.08126	$0.05982

MINIMUM MONTHLY BILL:

Minimum Monthly Bill:

1. Customer Charge; plus
2. Any additional charges for line extensions, if applicable.

SUMMER AND WINTER SEASONS:

The Summer Season is four consecutive months, beginning and effective May 16 and ending September 15, inclusive. The Winter Season is eight consecutive months, beginning and effective September 16 and ending May 15. Customer bills for meter reading periods including one or more days in both seasons will reflect the number of days in each season.

DETERMINATION OF MONTHLY MAXIMUM DEMAND:

The Monthly Maximum Demand shall be defined as the maximum fifteen (15) minute demand, measured in KW, during the peak period within the billing month. The peak period shall be the daily hours of 4:00 p.m. through 8:00 p.m. Central Time, excluding weekends and the following holidays: (1) New Year's Day; (2) Memorial Day; (3) Independence Day; (4) Labor Day; (5) Thanksgiving Day; and (6) Christmas Day.

RESIDENTIAL DEMAND SERVICE PILOT
Schedule RD (Continued)

ADJUSTMENTS AND SURCHARGES:

The rates hereunder are subject to adjustment as provided in the following schedules:

- Energy Cost Adjustment (ECA)
- Energy Efficiency Rider (EER)
- Property Tax Surcharge (PTS)
- Tax Adjustment (TA)
- Transmission Delivery Charge (TDC)

REGULATIONS:

Subject to Rules and Regulations filed with the State Regulatory Commission.

RESIDENTIAL DEMAND SERVICE PLUS TIME OF USE PILOT
Schedule RDTOU

AVAILABILITY:

Available to single-metered Residential customers receiving AMI-metered secondary electric service to a single-occupancy private residence or individually AMI-metered living units in multiple occupancy residential buildings.

Not available to Customers that own and operate generation connected in parallel with the Company's electric system that do not receive service under Net Metering tariff (Schedule NM).

Not available for Temporary, Seasonal, Three phase, Standby, Supplemental, or Resale or single metered multi-occupancy Residential Service.

APPLICABILITY:

This Demand Service Pilot shall be available as an option to customers otherwise served under the Company's Residential Service (Schedule R) to encourage customers to manage their demand and shift their energy.

This Pilot is limited to a maximum of one thousand (1,000) Residential customers, unless otherwise requested by the Company to be increased and such an increase in participation is approved by the State Regulatory Commission.

Any Customer who exits the program, has been disconnected for non-payment, or is on a pay agreement may not be allowed to participate in this pilot at the Company's discretion.

Service shall be provided for a fixed term of not less than one (1) year and for such time thereafter until terminated by either party via thirty (30) day written notice.

Participation in this pilot is contingent upon approval of this rate and adequate recovery of all costs (including marketing, customer education, and administrative costs) and lost margins associated with the pilot rate by the State Regulatory Commission. These rates may be packaged with approved Demand Side Management Pilot Programs where program costs are recovered through the Energy Efficiency Rider (Schedule EE).

RESIDENTIAL DEMAND SERVICE PLUS TIME OF USE PILOT
Schedule RDTOU (Continued)

RATE: RDTO2

		Summer Season	Winter Season
1.	Customer Charge (Per month)	$15.18	
2.	Demand Charge Per KW of Billing Demand per month	$14.000	$11.500
3.	Energy Charge (Per kWh)		
	Peak	$0.19562	$0.14405
	Off-Peak	$0.06521	$0.05363
	Super Off-Peak	$0.03260	$0.02259

PRICING PERIODS:

Pricing periods are established in Central Standard Time year annually, and by season, for weekdays and weekends. The hours of the pricing periods for each season are as follows:

On-Peak:	4pm-8pm
Off-Peak:	6am-4pm; 8pm-12am
Super Off-Peak:	12am-6am

MINIMUM:

Minimum Monthly Bill:

1. Customer Charge; plus
2. Any additional charges for line extensions, if applicable.

SUMMER AND WINTER SEASONS:

The Summer Season is four consecutive months, beginning and effective May 16 and ending September 15, inclusive. The Winter Season is eight consecutive months, beginning and effective September 16 and ending May 15. Customer bills for meter reading periods including one or more days in both seasons will reflect the number of days in each season.

RESIDENTIAL DEMAND SERVICE PLUS TIME OF USE PILOT
Schedule RDTOU (Continued)

DETERMINATION OF MONTHLY MAXIMUM DEMAND:

The Monthly Maximum Demand shall be defined as the maximum fifteen (15) minute demand, measured in KW, during the peak period within the billing month. The peak period shall be the daily hours of 4:00 p.m. through 8:00 p.m. Central Time, excluding weekends and the following holidays: (1) New Year's Day; (2) Memorial Day; (3) Independence Day; (4) Labor Day; (5) Thanksgiving Day; and (6) Christmas Day.

ADJUSTMENTS AND SURCHARGES:

The rates hereunder are subject to adjustment as provided in the following schedules:

- Energy Cost Adjustment (ECA)
- Energy Efficiency Rider (EER)
- Property Tax Surcharge (PTS)
- Tax Adjustment (TA)
- Transmission Delivery Charge (TDC)

REGULATIONS:

Subject to Rules and Regulations filed with the State Regulatory Commission.

PUBLIC ELECTRIC VEHICLE CHARGING STATION SERVICE
Schedule CCN

PURPOSE:

The Company owns electric vehicle (EV) charging stations throughout its Kansas service territory that are available to the public for purpose of charging an EV and may be used by any EV owner who resides either within or outside the Company's Kansas service territory.

AVAILABILITY:

This rate schedule applies to all energy provided to charge EVs at the Company's public EV charging stations. EV charging service will be available at Company-owned EV charging stations installed at Company and Host locations. The EV charging stations are accessed by using a card provided to users with an established account from the Company's third party vendor.

HOST PARTICIPATION:

EV charging stations are located at Company and Host sites. A Host is an entity within the Company's Kansas service territory that applies for and agrees to locate one or more Company EV charging stations on its premise(s). Host applications will be evaluated for acceptance based on each individual site and application. If a Host's application is approved, the Host must execute an agreement with the Company covering the terms and provisions applicable to the EV charging station(s) upon their premise. No Host shall receive any compensation for locating an EV charging station upon their premise(s).

The maximum number of EV charging stations identified by the Company for its Kansas service territory under this Schedule CCN is 350. The Company may not exceed 350 EV charging stations under this tariff without approval of the State Regulatory Commission.

PROGRAM ADMINISTRATION:

Charges under this Schedule CCN will be administered and billed through either the Company's third party vendor on behalf of the Company, or directly by the Company depending upon the Billing Option chosen by the Host.

BILLING OPTIONS:

The charges applicable to an EV charging station session shall include an Energy Charge for each kilowatt-hour (kWh) provided to charge an EV, and an optional Session Overstay Charge dependent on the Billing Option chosen by the Host.

PUBLIC ELECTRIC VEHICLE CHARGING STATION SERVICE
Schedule CCN (Continued)

BILLING OPTIONS: (Continued)

A Host may choose between one of two Billing Options for all EV charging stations located upon their premise(s). The Host's agreement with the Company will identify the chosen Billing Option applicable to EV charging stations located on its premise(s). The EV charging station screen, and third party vendor's customer web portal, identify the applicable Energy and Session Overstay Charges that will be the responsibility of the user at each EV charging station location.

1. Option 1: The Host pays the kWh Energy Charge plus applicable taxes and fees, and, if applicable, the EV charging station user pays the Session Overstay Charge.

2. Option 2: The EV charging station user pays the kWh Energy Charge plus taxes and fees, and, if applicable, the Session Overstay Charge.

RATES FOR SERVICE:

The EV charging station screen and third party vendor's customer web portal will identify both the: (1) per kWh rate as equal to the Energy Charge plus applicable taxes and fees; and (2) any Session Overstay Charge rate(s) applicable to that charging station.

1. Energy Charge (per kWh)

   Level 2: $0.20000

   Level 3: $0.25000

2. Session Overstay Charge (Optional) (per hour): $0.00 - $6.00

The Energy Charge shall be defined as a flat rate per kWh, and reflect the inclusion of the: (1) Energy Cost Adjustment (ECA); (2) Energy Efficiency Rider (EER); (3) Property Tax Surcharge (PTS); (4) Transmission Delivery Charge (TDC); and (5) Tax Adjustment (TA). A Session shall be defined as the period of time an EV is connected to the charging station. The Session Overstay Charge is an option that can be implemented at the discretion of the Host and Company to promote improved utilization of the EV charging station(s) located upon their premise.

PUBLIC ELECTRIC VEHICLE CHARGING STATION SERVICE
Schedule CCN (Continued)

RATES FOR SERVICE: (Continued)

The optional Session Overstay Charge will be configured within the following guidelines as either Charge-Based or Time-Based at the discretion of the Host.

1. Charge-Based – A Charge-Based Session Overstay Charge starts when the EV has stopped charging (but is still connected to the EV charging station) plus a defined grace period granting the user time to end the Charge Session and move the EV.

2. Time-Based – A Time-Based Session Overstay Charge starts at either the time of initial EV plug-in, or, a predefined time in an active Charge Session (*e.g.*, two hours after initial plug-in) at the Host's discretion and may increase to a higher rate at a subsequent predefined time in an active Charge Session (*e.g.,* four hours after initial plug-in).

Session Overstay Charges for fractional hours will be prorated. The Session Overstay Charge rate may not exceed $6.00 per hour.

BILLING:

All users of the Company's public EV charging stations must have an account with the Company's third party vendor. Information on opening an account can be found on the Company's website at http://kcpl.chargepoint.com/.

All charges applicable to any user of an EV charging station under Billing Option 1 or 2 will be billed directly through the Company's third party vendor. All charges applicable to the Host under Billing Option 1 will be billed directly through the Company.

REGULATIONS:

Subject to Rules and Regulations filed with the State Regulatory Commission.

RESIDENTIAL HOME ENERGY REPORT PILOT PROGRAM
Schedule RHER

PURPOSE:

The Residential Home Energy Report Pilot Program will directly support the three residential pilot schedules: (1) RTOU; (2) RD; and (3) RDTOU (Residential Pilots). Therefore, the program is directed to 3,000 residential customers who receive service under one of the three Residential Pilots. This Program is a behavioral energy efficiency and educational program that provides a comparison of the household energy usage information with similar types of customers, or “neighbors”. The Home Energy Report shall be delivered in paper, and/or email format, and is composed of several modules of information to help customers understand and manage their energy use. A few examples of modules included are: (1) neighbor/similar home comparison; (2) energy comparisons over time; (3) energy efficiency tips; and (4) utility program promotional material. The Home Energy Report provides information designed to influence customers’ behavior to lower energy usage.

AVAILABILITY:

Participation in this Program is limited to participants in the Residential Pilots only. This Program will operate as an opt-out only program, meaning the Company will select customers for participation in the program and will allow opt-out if desired.

PROGRAM FUNDING:

The total Program budget will be allocated between the following budget categories: (1) program delivery; (2) administration; and (3) evaluation (labor and loadings excluded from administration budget). This Program and its costs shall be eligible for recovery under the Company’s Energy Efficiency Rider, Schedule EE, subject to the provisions thereof.

EVALUATION:

The Company will hire a third-party evaluator to perform an Evaluation, Measurement, and Verification (EM&V) on the Home Energy Report Pilot Program.

RESIDENTIAL SMART THERMOSTAT PILOT PROGRAM
Schedule RSTP

PURPOSE:

The Residential Smart Thermostat Pilot Program will directly support the three residential pilot schedules: (1) RTOU; (2) RD; and (3) RDTOU (Residential Pilots). Therefore, the program is directed to 3,000 residential customers who receive service under one of the three Residential Pilots. Customers participating in one of the three Residential Pilots may receive a smart thermostat. This Program is intended to support residential customers in their transition to a Residential Pilot by providing them with a smart thermostat.

The smart thermostats have several features and capabilities that can help customers decrease their energy use, which include: (1) scheduled programming/learning capability; (2) recommended eco-temperatures; and (3) auto-away settings. The Company may leverage other technologies, and programs, to advance the smart thermostat software in an effort to maximize support to customers on a Residential Pilot by managing their energy use to meet Company objectives for load shaping.

AVAILABILITY:

Customers must maintain a secure home Wi-Fi enabled internet service and have a working central air conditioning system or heat pump. Residential property owner’s (owner occupant or landlord for a rental property) permission is required to receive a smart thermostat at an incentive level determined by the Company. Customers must agree to install the smart thermostat at their premise receiving service under one of the Residential Pilots within fourteen (14) days of receiving the device, and keep it installed, operational, and connected to a secure home Wi-Fi network for the duration of the program. Customers must agree to not sell the device for the duration of the program. If it is found that they do, a debit will be issued on their utility bill for the Manufacture Suggested Retail Price (MSRP) of the smart thermostat or the value of incentive provided to the customer. Payment of that debit will be the customer’s responsibility.

PROGRAM FUNDING:

The total Program budget will be allocated between the following budget categories: (1) program delivery; (2) marketing; (3) administration; and (4) evaluation (labor and loadings excluded from administration budget). This Program and its costs shall be eligible for recovery under the Company’s Energy Efficiency Rider, Schedule EE, subject to the provisions thereof.

EVALUATION:

The Company will hire a third-party evaluator to perform an Evaluation, Measurement, and Verification (EM&V) on this Program.

DEMAND SERVICE FOR RESIDENTIAL DISTRIBUTED GENERATION
Schedule RDG

AVAILABILITY:

Any Customer-Generator operating or adding generation powered by Renewable Energy Resources or taking service under an interconnection agreement connecting to KCP&L's distribution system after XXX XX, XXX (effective date of rates in this case) must take service under this rate schedule.

For electric service to a single-occupancy private residence. Single-phase electric service through one meters for ordinary domestic use for all customers who request to be served under this rate. The Company reserves the right in all instances to designate whether a Customer-Generator is or is not a residential customer.

Three-phase electric service for the operation of cooling and air conditioning equipment for domestic use. For three-phase, built-up central plant air conditioning systems of at least 25 tons single-unit cooling capacity, service is available under this schedule only if permitted by the Company, with the Company exercising sole discretion in the case of each Customer-Generator. The availability of three-phase Residential Service for such air conditioning systems also shall be contingent upon the Customer-Generator paying the full cost of the required three-phase line extension prior to construction of the extension.

Single-phase electric service through a single or separately metered circuit for space heating purposes in the residence. Single metered electric space heating equipment shall be of a size and design sufficient to heat the entire residence. Electric space heating equipment may be supplemented by wood burning fireplaces, wood burning stoves, active or passive solar heating, and used in conjunction with fossil fuels where the combination of energy sources results in a net economic benefit to the Customer-Generator. Electric space heating equipment shall be permanently installed and thermostatically controlled.

Customers currently served under two meter heat rates shall be required to convert their metering from two meters to a single meter or agree to provisions to combine the readings from the two meters when billed under this schedule.

Not available for Temporary, Seasonal, Standby, or Resale Service.

TERM OF CONTRACT:

Contracts under this schedule shall be for a period of not less than one year from the effective date thereof.

DEMAND SERVICE FOR RESIDENTIAL DISTRIBUTED GENERATION
Schedule RDG (Continued)

DEFINITIONS:

1. Customer-Generator: The owner and operator of a facility which:

   A. Is powered by a Renewable Energy Resource;
   B. Is located on a premise owned, operated, leased, or otherwise controlled by the Customer-Generator;
   C. Is interconnected and operates in parallel phase and synchronization with the Company facilities and is in compliance with the Company standards;
   D. Is intended primarily to offset part or all of the Customer-Generator's own electrical energy requirements; and
   E. Contains a mechanism, approved by the Company that automatically disables the unit and interrupts the flow of electricity back onto the Company's electric lines in the event that service to the Customer-Generator is interrupted.

2. Renewable Energy Resources: Net renewable generation capacity produced from wind, solar thermal sources, photovoltaic cells and panels, dedicated crops grown for energy production, cellulosic agricultural residues, plant residues, methane from landfills or from wastewater treatment, clean and untreated wood products such as pallets, hydroelectric sources (existing hydropower, new hydropower, not including pumped storage, that has a name plate rating of 10 megawatts or less), fuel cells using hydrogen produced by one of the above-named renewable energy sources; and other sources of energy, not including nuclear power, that become available, and that are certified as renewable by the rules and regulations of the Kansas Corporation Commission.

RATE: 2RSDG

Single-phase and Three-phase service will be cumulated for billing under this schedule.

		Summer Season	Winter Season
1.	Customer Charge (Per month)	$14.00	
2.	Demand Charge Per KW of Billing Demand per month	$9.000	$2.000
3.	Energy Charge (Per kWh) All Energy	$0.08683	$0.06704

DEMAND SERVICE FOR RESIDENTIAL DISTRIBUTED GENERATION
Schedule RDG (Continued)

MINIMUM MONTHLY BILL:

Minimum Monthly Bill:

1. Customer Charge; plus
2. Any additional charges for line extensions, if applicable.

SUMMER AND WINTER SEASONS:

The Summer Season is four consecutive months, beginning and effective May 16 and ending September 15, inclusive. The Winter Season is eight consecutive months, beginning and effective September 16 and ending May 15. Customer bills for meter reading periods including one or more days in both seasons will reflect the number of days in each season.

DETERMINATION OF MONTHLY BILLING DEMAND:

The Monthly Billing Demand shall be defined as the maximum fifteen (15) minute demand, measured in KW, during the peak period within the billing month. The peak period shall be the daily hours of 4:00 p.m. through 8:00 p.m. Central Time, excluding weekends, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

ADJUSTMENTS AND SURCHARGES:

The rates hereunder are subject to adjustment as provided in the following schedules:

- Energy Cost Adjustment (ECA)
- Energy Efficiency Rider (EER)
- Property Tax Surcharge (PTS)
- Tax Adjustment (TA)
- Transmission Delivery Charge (TDC)

REGULATIONS:

Subject to Rules and Regulations filed with the State Regulatory Commission.

Issued: May 1, 2018
Month Day Year

Effective: ______
Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

SMALL GENERAL SERVICE
Schedule SGS (Continued)

RATE FOR SERVICE AT SECONDARY VOLTAGE: 2SGHE, 2SGHH, 2SGSE, 2SGSH, 2SUSE, 2SUSH,

1. CUSTOMER CHARGE:

A. For Metered Service:

a.) Customer pays one of the following charges per month based upon the Facilities Demand:

0-24 kW	$21.70
25 kW or above	$56.73

b.) plus, additional meter charge for Customers with separately metered space heat: $2.57

B. For Unmetered Service Customer pays: $9.32

2. FACILITIES CHARGE:

Per kW of Facilities Demand per month

First 25 kW	$0.00
All kW over 25 kW	$3.343

3. ENERGY CHARGE:

Per kWh associated with:	Summer Season	Winter Season
First 180 Hours Use per month	$0.14429 per kWh	$0.11484 per kWh
Next 180 Hours Use per month	$0.06337 per kWh	$0.05413 per kWh
Over 360 Hours Use per month	$0.05662 per kWh	$0.04268 per kWh

4. SEPARATELY METERED SPACE HEAT: 2SGHE, 2SGHH

When the customer has separately metered electric space heating equipment of a size and design approved by the Company, the kWh used for electric space heating shall be billed as follows:

A. Applicable during the Winter Season:
$0.04894 per kWh per month.

B. Applicable during the Summer Season:
The demand established and energy used by equipment connected to the space heating circuit will be added to the demands and energy measured for billing under the rates above and for the determination of the Minimum Monthly Bill.

SMALL GENERAL SERVICE
Schedule SGS (Continued)

RATE FOR SERVICE AT PRIMARY VOLTAGE: 2SGSF, 2SGSG

1. CUSTOMER CHARGE:

   A. For Metered Service:
   Customer pays one of the following charges per month based upon the Facilities Demand:

0-24 kW	$21.70
25 kW or above	$56.73

2. FACILITIES CHARGE:
   Per kW of Facilities Demand per month

First 26 kW	$0.00
All kW over 26 kW	$2.829

3. ENERGY CHARGE:

Per kWh associated with:	Summer Season	Winter Season
First 180 Hours Use per month	$0.14067 per kWh	$0.11191 per kWh
Next 180 Hours Use per month	$0.06162 per kWh	$0.05279 per kWh
Over 360 Hours Use per month	$0.05514 per kWh	$0.04150 per kWh

SMALL GENERAL SERVICE
Schedule SGS (Continued)

REACTIVE DEMAND ADJUSTMENT (Secondary and Primary Service):

Company may determine the customer's monthly maximum 30-minute reactive demand in kilovars. In each month a charge of $0.786 per month shall be made for each kilovar by which such maximum reactive demand is greater than fifty percent (50%) of the customer's Monthly Maximum Demand (kW) in that month. The maximum reactive demand in kilovars shall be computed similarly to the Monthly Maximum Demand as defined in the Determination of Demands section.

MINIMUM MONTHLY BILL:

The Minimum Monthly Bill shall be equal to the sum of the Customer Charge, Facilities Charge, and Reactive Demand Adjustment.

UNMETERED SERVICE:

Unmetered secondary service refers to electric service which is not measured by a kWh meter or by a kWh/demand meter. This type of service usually applies to delivery points for which it is impractical or difficult to install and read meters. The usage and demand are calculated by using typical hours of use and rated equipment loads.

SUMMER AND WINTER SEASONS:

The Summer Season is four consecutive months, beginning and effective May 16 and ending September 15, inclusive. The Winter Season is eight consecutive months, beginning and effective September 16 and ending May 15. Customer bills for meter reading periods including one or more days in both seasons will reflect the number of days in each season.

CUSTOMER DEFINITIONS:

1. Secondary Voltage Customer - Receives service on the low side of the line transformer.

2. Primary Voltage Customer - Receives service at Primary voltage of 12,000 volts or over but not exceeding 69,000 volts. Customer will own all equipment necessary for transformation including the line transformer.

3. Water Heating Customer - Customer connected prior to March 1, 1999, that receives service through a separately metered circuit as the sole means of water heating with an electric water heater of a size and design approved by the Company.

MEDIUM GENERAL SERVICE
Schedule MGS (Continued)

RATE FOR SERVICE AT SECONDARY VOLTAGE: 2MGHE, 2MGHH, 2MGSE, 2MGSH

1. CUSTOMER CHARGE:

   A. Customer pays the following charge per month: $54.69

   B. plus, additional meter charge for customers with separately metered space heat: $2.56

2. FACILITIES CHARGE:
   Per kW of Facilities Demand per month $3.192

3. DEMAND CHARGE:

	Summer Season	Winter Season
Per kW of Billing Demand per month	$4.466	$2.263

4. ENERGY CHARGE:

Per kWh associated with:	Summer Season	Winter Season
First 180 Hours Use per month	$0.09178 per kWh	$0.08218 per kWh
Next 180 Hours Use per month	$0.05754 per kWh	$0.04613 per kWh
Over 360 Hours Use per month	$0.05822 per kWh	$0.03882 per kWh

5. SEPARATELY METERED SPACE HEAT: 2MGHE, 2MGHH

   When the customer has separately metered electric space heating equipment of a size and design approved by the Company, the kWh used for electric space heating shall be billed as follows:

   A. Applicable during the Winter Season:
      $0.02814 per kWh per month.

   B. Applicable during the Summer Season:
      The demand established and energy used by equipment connected to the space heating circuit will be added to the demands and energy measured for billing under the rates above and for the determination of the Minimum Monthly Bill.

MEDIUM GENERAL SERVICE
Schedule MGS (Continued)

RATE FOR SERVICE AT PRIMARY VOLTAGE: 2MGSF, 2MGSG

1. CUSTOMER CHARGE:
   Customer pays the following charge per month: $54.69

2. FACILITIES CHARGE:
   Per kW of Facilities Demand per month $2.702

3. DEMAND CHARGE:

	Summer Season	Winter Season
Per kW of Billing Demand per month	$4.370	$2.219

4. ENERGY CHARGE:

Per kWh associated with:	Summer Season	Winter Season
First 180 Hours Use per month	$0.08949 per kWh	$0.08031 per kWh
Next 180 Hours Use per month	$0.05574 per kWh	$0.04505 per kWh
Over 360 Hours Use per month	$0.05327 per kWh	$0.03547 per kWh

MEDIUM GENERAL SERVICE
Schedule MGS (Continued)

REACTIVE DEMAND ADJUSTMENT (Secondary and Primary Service):

Company may determine the customer's monthly maximum 30-minute reactive demand in kilovars. In each month a charge of $0.739 per month shall be made for each kilovar by which such maximum reactive demand is greater than fifty percent (50%) of the customer's Monthly Maximum Demand (kW) in that month. The maximum reactive demand in kilovars shall be computed similarly to the Monthly Maximum Demand as defined in the Determination of Demands section.

MINIMUM MONTHLY BILL:

The Minimum Monthly Bill shall be equal to the sum of the Customer Charge, Facilities Charge, Demand Charge, and Reactive Demand Adjustment.

SUMMER AND WINTER SEASONS:

The Summer Season is four consecutive months, beginning and effective May 16 and ending September 15, inclusive. The Winter Season is eight consecutive months, beginning and effective September 16 and ending May 15. Customer bills for meter reading periods including one or more days in both seasons will reflect the number of days in each season.

CUSTOMER DEFINITIONS:

1. Secondary Voltage Customer - Receives service on the low side of the line transformer.

2. Primary Voltage Customer - Receives service at Primary voltage of 12,000 volts or over but not exceeding 69,000 volts. Customer will own all equipment necessary for transformation including the line transformer.

3. Water Heating Customer - Customer connected prior to March 1, 1999, that receives service through a separately metered circuit as the sole means of water heating with an electric water heater of a size and design approved by the Company.

LARGE GENERAL SERVICE
Schedule LGS (Continued)

RATE FOR SERVICE AT SECONDARY VOLTAGE: 2LGHE, 2LGHH, 2LGSE, 2LGSH

1. CUSTOMER CHARGE:

   A. Customer pays one of the following charges per month based upon the Facilities Demand:

0 - 999 kW	$114.38
1000 kW or above	$782.28

   B. plus, additional meter charge for customers with separately metered space heat: $2.53

2. FACILITIES CHARGE:
   Per kW of Facilities Demand per month $3.313

3. DEMAND CHARGE:

	Summer Season	Winter Season
Per kW of Billing Demand per month	$7.146	$3.627

4. ENERGY CHARGE:

Per kWh associated with:	Summer Season	Winter Season
First 180 Hours Use per month	$0.06879 per kWh	$0.06895 per kWh
Next 180 Hours Use per month	$0.04916 per kWh	$0.04189 per kWh
Over 360 Hours Use per month	$0.02811 per kWh	$0.03130 per kWh

5. SEPARATELY METERED SPACE HEAT: 2LGHE, 2LGHH

When the customer has separately metered electric space heating equipment of a size and design approved by the Company, the kWh used for electric space heating shall be billed as follows:

A. Applicable during the Winter Season:
$0.02695 per kWh per month.

B. Applicable during the Summer Season:
The demand established and energy used by equipment connected to the space heating circuit will be added to the demands and energy measured for billing under the rates above and for the determination of the Minimum Monthly Bill.

LARGE GENERAL SERVICE
Schedule LGS (Continued)

RATE FOR SERVICE AT PRIMARY VOLTAGE: 2LGSF, 2LGSG

1. CUSTOMER CHARGE:
   Customer pays one of the following charges per month based upon the Facilities Demand:

0 - 999 kW	$114.38
1000 kW or above	$782.28

2. FACILITIES CHARGE:

Per kW of Facilities Demand per month	$2.781

3. DEMAND CHARGE:

	Summer Season	Winter Season
Per kW of Billing Demand per month	$7.012	$3.548

4. ENERGY CHARGE:

Per kWh associated with:	Summer Season	Winter Season
First 180 Hours Use per month	$0.06682 per kWh	$0.06681 per kWh
Next 180 Hours Use per month	$0.04769 per kWh	$0.04092 per kWh
Over 360 Hours Use per month	$0.02705 per kWh	$0.03052 per kWh

LARGE GENERAL SERVICE
Schedule LGS (Continued)

RATE FOR SERVICE AT SUBSTATION VOLTAGE: 2LGSU, 2LGSV

1. CUSTOMER CHARGE:
   Customer pays the following charge per month: $835.11

2. FACILITIES CHARGE:
   Per kW of Facilities Demand per month $0.882

3. DEMAND CHARGE:

Per kW of Billing Demand per month	Summer Season	Winter Season
First 2520 kW	$12.150	$8.258
Next 2520 kW	$11.347	$7.528
Next 2520 kW	$8.357	$5.835
All kW over 7560 kW	$6.099	$4.490

4. ENERGY CHARGE:

Per kWh associated with:	Summer Season	Winter Season
First 180 Hours Use per month	$0.05717 per kWh	$0.05347 per kWh
Next 180 Hours Use per month	$0.03465 per kWh	$0.03776 per kWh
Over 360 Hours Use per month	$0.02005 per kWh	$0.02728 per kWh

LARGE GENERAL SERVICE
Schedule LGS (Continued)

RATE FOR SERVICE AT TRANSMISSION VOLTAGE: 2LGSW, 2LGSZ

1. CUSTOMER CHARGE:
   Customer pays the following charge per month: $835.11

2. FACILITIES CHARGE:
   Per kW of Facilities Demand per month $0.000

3. DEMAND CHARGE:

Per kW of Billing Demand per month	Summer Season	Winter Season
First 2541 kW	$12.040	$8.184
Next 2541 kW	$11.247	$7.462
Next 2541 kW	$8.309	$5.802
All kW over 7623 kW	$6.066	$4.465

4. ENERGY CHARGE:

Per kWh associated with:	Summer Season	Winter Season
First 180 Hours Use per month	$0.05645 per kWh	$0.05291 per kWh
Next 180 Hours Use per month	$0.03422 per kWh	$0.03733 per kWh
Over 360 Hours Use per month	$0.01961 per kWh	$0.02683 per kWh

REACTIVE DEMAND ADJUSTMENT (Secondary, Primary, Substation, and Transmission Service):

Company may determine the customer’s monthly maximum 30-minute reactive demand in kilovars. In each month a charge of $0.752 per month shall be made for each kilovar by which such maximum reactive demand is greater than fifty percent (50%) of the customer’s Monthly Maximum Demand (kW) in that month. The maximum reactive demand in kilovars shall be computed similarly to the Monthly Maximum Demand as defined in the Determination of Demands section.

MINIMUM MONTHLY BILL:

The Minimum Monthly Bill shall be equal to the sum of the Customer Charge, Facilities Charge, Demand Charge, and Reactive Demand Adjustment.

LARGE GENERAL SERVICE OFF-PEAK RIDER
Schedule LGS-2

PROVISIONS:

During Off-Peak hours, subject to the conditions hereinafter stated, the Customer may exceed his On-Peak Demand and not be billed for such excess demand.

DEFINITIONS:

1. Off-Peak hours shall be the hours between 7:00 p.m. and 11:00 a.m. of the following day, and all hours between 7:00 p.m. Friday and 11:00 a.m. of the following Monday. All hours shall be considered Off-Peak for the following holidays: (1) New Year’s Day; (2) Memorial Day; (3) Independence Day; (4) Labor Day; (5) Thanksgiving Day; and (6) Christmas Day.

2. On-Peak hours are all hours other than Off-Peak hours.

3. On-Peak Demand is the highest 30-minute demand established by the Customer during On-Peak hours.

4. Off-Peak Demand is the highest 30-minute demand established by the Customer during Off-Peak hours.

CONDITIONS:

1. The Customer’s premise(s) must be serviced and billed using a Company meter capable of measuring demand.

2. The Customer must make a written request and the Company shall, in its sole judgment, determine whether sufficient reason exists for the application of this provision. The Company shall notify the Customer in writing of its determination to accept or reject the Customer’s request.

3. The Customer’s Off-Peak Demand may exceed the Customer’s On-Peak Demand during such Off-Peak Hours to the extent which the Company shall, in its sole judgment, determine that its generating and delivery facilities have sufficient capacity to permit supplying such excess demand without disturbing service to its other Customers. The Company may supply the Customer, in writing, a schedule of such excess demands which may be imposed during Off-Peak Hours. The Company may, upon thirty (30) day’s written notice, change such schedule.

4. Nothing in this provision shall be construed as requiring the Company to provide additional generating or delivery facilities for such excess demand.

LARGE GENERAL SERVICE OFF-PEAK RIDER
Schedule LGS-2 (Continued)

CONDITIONS: (Continued)

5. If the Customer's Off-Peak Demand is within the limits outlined in Condition 3 hereof, the Customer's Monthly Maximum Demand shall be based on the Customer's On-Peak Demand.

6. The Company, during Off-Peak Hours, in the event of an emergency which would affect deliveries to its other Customers, may require the curtailment of all or part of such Off-Peak Demand which is in excess of the On-Peak Demand.

7. That portion of any demand established in a month during the Off-Peak Hours which is above the Off-Peak Demand allowed by the Company shall be added to the highest demand established during On-Peak Hours in such month for the purpose of determining the Monthly Maximum Demand.

8. In the event that service under this provision is made available to more than one Customer, the available generating and delivery capacity may be prorated on the basis of the prior month's On-Peak Demands if sufficient capacity is not available to supply the total amount requested.

9. Depending upon energy supply and cost conditions, the Company may temporarily extend the Off-Peak Hours. The Extended Off-Peak Hours will only be available to Customers whose Off-Peak Demands during normal Off-Peak Hours regularly exceed their On-Peak Demands, and who make written request to the Company for Extended Off-Peak Hours. The Company, in its sole judgment, may alter, or cancel, all, or a portion, of Extended Off-Peak Hours upon telephone or fax notice to the Customer. Upon notification of cancellation of Extended Off-Peak Hours the Customer shall adjust demand, at the time the cancellation is to take effect or within sixty (60) minutes if the cancellation is effective immediately, to not exceed the level of the Customer's then current On-Peak Demand. If a Customer fails to maintain a demand at or below the then current On-Peak Demand during any portion of the cancelled Extended Off-Peak Hours, then 30-minute Demands established after the effective time of the cancellation or after the sixty (60) minute grace period, if applicable, shall be considered in the determination of the On-Peak Demand, and that Customer may be ineligible for Extended Off-Peak Hours for a period of twelve (12) months.

SMALL GENERAL SERVICE – SPACE HEATING
Schedule SGA (Continued)

RATE FOR SERVICE AT SECONDARY VOLTAGE: 2SGAE, 2SGAH

1. CUSTOMER CHARGE:
   Customer pays one of the following charges per month based upon the Facilities Demand:

0 - 24 kW	\$21.70
25 kW or above	\$56.73

2. FACILITIES CHARGE:
   Per kW of Facilities Demand per month

First 25 kW	\$0.000
All kW over 25 kW	\$3.343

3. ENERGY CHARGE:

Per kWh associated with:	Summer Season	Winter Season
First 180 Hours Use per month	\$0.14429 per kWh	\$0.07809 per kWh
Next 180 Hours Use per month	\$0.06337 per kWh	\$0.04739 per kWh
Over 360 Hours Use per month	\$0.05662 per kWh	\$0.04140 per kWh

SMALL GENERAL SERVICE – SPACE HEATING
Schedule SGA (Continued)

RATE FOR SERVICE AT PRIMARY VOLTAGE: 2SGAF, 2SGAG

1. CUSTOMER CHARGE:
   Customer pays one of the following charges per month based upon the Facilities Demand:

0 - 24 kW	$21.70
25 W or above	$56.73

2. FACILITIES CHARGE
   Per kW of Facilities Demand per month

First 26 kW	$0.00
All kW over 26 kW	$2.829

3. ENERGY CHARGE:

Per kWh associated with:	Summer Season	Winter Season
First 180 Hours Use per month	$0.14067 per kWh	$0.07621 per kWh
Next 180 Hours Use per month	$0.06162 per kWh	$0.04617 per kWh
Over 360 Hours Use per month	$0.05514 per kWh	$0.04011 per kWh

SMALL GENERAL SERVICE – SPACE HEATING
Schedule SGA (Continued)

REACTIVE DEMAND ADJUSTMENT (Secondary and Primary Service):

Company may determine the customer's monthly maximum 30-minute reactive demand in kilovars. In each month a charge of $0.786 per month shall be made for each kilovar by which such maximum reactive demand is greater than fifty percent (50%) of the customer's Monthly Maximum Demand (kW) in that month. The maximum reactive demand in kilovars shall be computed similarly to the Monthly Maximum Demand as defined in the Determination of Demands section.

MINIMUM MONTHLY BILL:

The Minimum Monthly Bill shall be equal to the sum of the Customer Charge, Facilities Charge, and Reactive Demand Adjustment.

SUMMER AND WINTER SEASONS:

The Summer Season is four consecutive months, beginning and effective May 16 and ending September 15, inclusive. The Winter Season is eight consecutive months, beginning and effective September 16 and ending May 15. Customer bills for meter reading periods including one or more days in both seasons will reflect the number of days in each season.

CUSTOMER DEFINITIONS:

1. Secondary Voltage Customer - Receives service on the low side of the line transformer.

2. Primary Voltage Customer - Receives service at Primary voltage of 12,000 volts or over but not exceeding 69,000 volts. Customer will own all equipment necessary for transformation including the line transformer.

MEDIUM GENERAL SERVICE – SPACE HEATING
Schedule MGA (Continued)

RATE FOR SERVICE AT SECONDARY VOLTAGE: 2MGAE, 2MGAH

1. CUSTOMER CHARGE:
   Customer pays the following charge per month: $54.69

2. FACILITIES CHARGE:
   Per kW of Facilities Demand per month $3.192

3. DEMAND CHARGE:

	Summer Season	Winter Season
Per kW of Billing Demand per month	$4.466	$3.103

4. ENERGY CHARGE:

Per kWh associated with:	Summer Season	Winter Season
First 180 Hours Use per month	$0.09178 per kWh	$0.04846 per kWh
Next 180 Hours Use per month	$0.05754 per kWh	$0.02935 per kWh
Over 360 Hours Use per month	$0.05822 per kWh	$0.02551 per kWh

Issued: May 1, 2018
Month Day Year

Effective:
Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

MEDIUM GENERAL SERVICE – SPACE HEATING
Schedule MGA (Continued)

RATE FOR SERVICE AT PRIMARY VOLTAGE: 2MGAF, 2MGAG

1. CUSTOMER CHARGE:
   Customer pays the following charge per month: $54.69

2. FACILITIES CHARGE:
   Per kW of Facilities Demand per month $2.702

3. DEMAND CHARGE:

	Summer Season	Winter Season
Per kW of Billing Demand per month	$4.370	$3.036

4. ENERGY CHARGE:

Per kWh associated with:	Summer Season	Winter Season
First 180 Hours Use per month	$0.08949 per kWh	$0.04712 per kWh
Next 180 Hours Use per month	$0.05574 per kWh	$0.02853 per kWh
Over 360 Hours Use per month	$0.05327 per kWh	$0.02481 per kWh

MEDIUM GENERAL SERVICE – SPACE HEATING
Schedule MGA (Continued)

REACTIVE DEMAND ADJUSTMENT (Secondary and Primary Service):

Company may determine the customer's monthly maximum 30-minute reactive demand in kilovars. In each month a charge of $0.739 per month shall be made for each kilovar by which such maximum reactive demand is greater than fifty percent (50%) of the customer's Monthly Maximum Demand (kW) in that month. The maximum reactive demand in kilovars shall be computed similarly to the Monthly Maximum Demand as defined in the Determination of Demands section.

MINIMUM MONTHLY BILL:

The Minimum Monthly Bill shall be equal to the sum of the Customer Charge, Facilities Charge, Demand Charge, and Reactive Demand Adjustment.

SUMMER AND WINTER SEASONS:

The Summer Season is four consecutive months, beginning and effective May 16 and ending September 15, inclusive. The Winter Season is eight consecutive months, beginning and effective September 16 and ending May 15. Customer bills for meter reading periods including one or more days in both seasons will reflect the number of days in each season.

CUSTOMER DEFINITIONS:

1. Secondary Voltage Customer - Receives service on the low side of the line transformer.

2. Primary Voltage Customer - Receives service at Primary voltage of 12,000 volts or over but not exceeding 69,000 volts. Customer will own all equipment necessary for transformation including the line transformer.

LARGE GENERAL SERVICE – SPACE HEATING
Schedule LGA (Continued)

RATE FOR SERVICE AT SECONDARY VOLTAGE: 2LGAE, 2LGAH

1. CUSTOMER CHARGE:
   Customer pays one of the following charges per month based upon the Facilities Demand:

0 - 999 kW	$114.38
1000 kW or above	$782.28

2. FACILITIES CHARGE:

Per kW of Facilities Demand per month	$3.313

3. DEMAND CHARGE:

	Summer Season	Winter Season
Per kW of Billing Demand per month	$7.146	$3.302

4. ENERGY CHARGE:

Per kWh associated with:	Summer Season	Winter Season
First 180 Hours Use per month	$0.06879 per kWh	$0.04812 per kWh
Next 180 Hours Use per month	$0.04916 per kWh	$0.03002 per kWh
Over 360 Hours Use per month	$0.02811 per kWh	$0.02465 per kWh

LARGE GENERAL SERVICE – SPACE HEATING
Schedule LGA (Continued)

RATE FOR SERVICE AT PRIMARY VOLTAGE: 2LGAF, 2LGAG

1. CUSTOMER CHARGE:
   Customer pays one of the following charges per month based upon the Facilities Demand:

0 - 999 kW	$114.38
1000 kW or above	$782.28

2. FACILITIES CHARGE:

Per kW of Facilities Demand per month	$2.781

3. DEMAND CHARGE:

	Summer Season	Winter Season
Per kW of Billing Demand per month	$7.012	$3.240

4. ENERGY CHARGE:

Per kWh associated with:	Summer Season	Winter Season
First 180 Hours Use per month	$0.06682 per kWh	$0.04684 per kWh
Next 180 Hours Use per month	$0.04769 per kWh	$0.02903 per kWh
Over 360 Hours Use per month	$0.02705 per kWh	$0.02389 per kWh

LARGE GENERAL SERVICE – SPACE HEATING
Schedule LGA (Continued)

REACTIVE DEMAND ADJUSTMENT (Secondary and Primary Service):

Company may determine the customer's monthly maximum 30-minute reactive demand in kilovars. In each month a charge of $0.752 per month shall be made for each kilovar by which such maximum reactive demand is greater than fifty percent (50%) of the customer's Monthly Maximum Demand (kW) in that month. The maximum reactive demand in kilovars shall be computed similarly to the Monthly Maximum Demand as defined in the Determination of Demands section.

MINIMUM MONTHLY BILL:

The Minimum Monthly Bill shall be equal to the sum of the Customer Charge, Facilities Charge, Demand Charge, and Reactive Demand Adjustment.

SUMMER AND WINTER SEASONS:

The Summer Season is four consecutive months, beginning and effective May 16 and ending September 15, inclusive. The Winter Season is eight consecutive months, beginning and effective September 16 and ending May 15. Customer bills for meter reading periods including one or more days in both seasons will reflect the number of days in each season.

CUSTOMER DEFINITIONS:

1. Secondary Voltage Customer - Receives service on the low side of the line transformer.

2. Primary Voltage Customer - Receives service at Primary voltage of 12,000 volts or over but not exceeding 69,000 volts. Customer will own all equipment necessary for transformation including the line transformer.

STANDBY SERVICE RIDER
Schedule SSR

APPLICABILITY:

Applicable to each Customer at a single premise(s) with behind-the-meter, on-site parallel Distributed Generation system(s) with a capacity greater than or equal to 100 kilowatts (kW), as a modification to standard electric service supplied under either the tariffed rate schedules of Small General Service (Schedule SGS or SGA), Medium General Service (Schedule MGS or MGA), or Large General Service (Schedule LGS or LGA). Customers must receive service under a standard rate schedule that includes a Facilities Charge and a Demand Charge. Provision of this Rider will be based on the nameplate rating of the Distributed Generation.

Customers with emergency backup, intermittent renewable generation, or energy storage systems are excluded from this Schedule SSR.

DEFINITIONS:

1. Distributed Generation – Customer's private, on-site generation that:

   A. is located behind the meter on the Customer's premise(s);

   B. has a nameplate capacity of greater than or equal to 100 KW;

   C. operates in parallel with the Company's system; and

   D. adheres to an applicable interconnection agreement entered into with the Company.

2. Standby Contract Capacity – Shall be the LESSER of:

   A. The sum of nameplate rating(s) of all Customer Distributed Generation systems;

   B. The sum of nameplate rating(s) less any generation on the same premises used exclusively for generation redundancy purposes; and

   C. The number of kilowatts mutually agreed upon by Company as representing the Customer's Standby Capacity requirements based on a Company approved Customer load curtailment plan. Any evidence that the load curtailment plan is not used as intended will result in the Standby Contract Capacity being reset to one of the other alternatives.

STANDBY SERVICE RIDER
Schedule SSR (Continued)

RATES:

1. **For Customers with Standby Contract Capacity greater than or equal to 100kW and less than or equal to 2MW**

   A. Capacity Reservation Charge — An additional charge, based on the size of the Distributed Generation, applied to recover the cost of providing and maintaining the generation and transmission facilities required to support the capacity requirements of the Customer within the Company system.

   B. Interconnection Charge — A charge applied in place of the Facility Charge associated with the standard rate, to recover the cost of providing and maintaining the distribution facilities required to interconnect the Customer to the Company system that are normally embedded in the volumetric energy charge of the standard rate.

   C. Supplemental Service Charge — A charge for electric service (demand and energy) provided by the Company to the Customer to supplement normal operation of the Customer's Distributed Generation system to meet the Customer's full service requirements. Supplemental Service will be deemed to occur if the Customer's Metered Grid Interconnection Load is positive. Supplemental Service will be supplied at the applicable rates under the standard rate schedule.

   D. Excess Generation Credit — If the Customer's Metered Grid Interconnection Load is negative, the excess energy received by the Company system will be credited at the then current Parallel Generation rate, as defined in Schedule PG.

	Small General Service	Medium General Service	Large General Service
Capacity Reservation Charge (per kW of Standby Contract Capacity)	$1.117	$1.117	$1.787
Interconnection Charge (per kW of Standby Contract Capacity)	$6.686	$6.384	$6.626

Supplemental Service Charge — All service will be supplied at the applicable rates under the standard rate schedule.

Excess Generation Credit — Excess energy will be credited at the current Parallel Generation rate as defined in Schedule PG.

STANDBY SERVICE RIDER
Schedule SSR (Continued)

RATES: (Continued)

2. For Customers with Standby Contract Capacity between greater than 2MW and less than or equal to 10MW

A. Minimum Operating Limit — 90% of the Standby Contract Capacity.

B. Metered Grid Interconnection Load — all metered Customer usage from the Company system. Metering will measure both energy consumed and excess energy, if any, delivered back to the Company system.

C. Metered Generation Output — all metered output from the Customer's Distributed Generation system.

D. Total Customer Load — is the Metered Grid Interconnection Load plus the Metered Generation Output.

E. Standby Service Metering & Administrative Charge — A charge to cover additional meter costs, meter data processing, billing, and administrative costs beyond those covered in the standard tariff.

F. Supplemental Service Charge — A charge for electric service (demand and energy) provided by the Company to the Customer to supplement normal operation of the Customer's Distributed Generation system to meet the Customer's full service requirements. Supplemental Service will be deemed to occur if the Customer's Total Load is greater than the Metered Generation Output and greater than the Minimum Operating Limit.

G. Backup Service — Electric service (demand and energy) provided by the Company to Customer premises to replace capacity and energy normally produced by the Customer's Distributed Generation (formerly referred to as Breakdown service). Backup Service will be deemed to occur if the Metered Generation Output is less than the Minimum Operating Limit and less than the Total Customer Load during any time in the Summer period. Seasonal periods are defined in the applicable standard rate schedule.

H. Maintenance Service — Electric service (demand and energy) provided by the Company to customer premises to replace capacity and energy normally produced by the Customer's Distributed Generation. Maintenance Service will be deemed to occur if the Metered Generation Output is less than the Minimum Operating Limit and less than the Total Customer Load during any time in the Winter period. Seasonal periods are defined in the applicable standard rate schedule.

STANDBY SERVICE RIDER
Schedule SSR (Continued)

RATES: (Continued)

I. Excess Generation Credit — If the Customer's Metered Grid Interconnection Load is negative, the excess energy received by the Company system will be credited at the then current Parallel Generation rate, as defined in Schedule PG.

	Small General Service	**Medium General Service**	**Large General Service**
Standby Service Metering & Administrative Charge (per month)	$140.00	$140.00	$160.00
Capacity Reservation Charge (per kW of Standby Contract Capacity)	$1.117	$1.117	$1.787
Demand Rate (per kW of Monthly Backup or Maintenance Demand):			
Backup Service	$0.186	$0.186	$0.298
Maintenance Service	$0.149	$0.149	$0.238
Energy Charge (per kWh of Monthly Backup or Maintenance Energy):			
Backup Service	$0.14429	$0.09178	$0.06879
Maintenance Service	$0.06337	$0.05754	$0.04916

Supplemental Service Charge: All service will be supplied at the applicable rates under the standard rate schedule.

Excess Generation Credit: Excess energy will be credited at the current Parallel Generation rate, as defined in Schedule PG.

Where:

a) Daily Backup Demand shall equal the Maximum Backup Demand metered during a calendar day;

b) Monthly Backup Demand shall equal the sum of the Daily Backup Demands for the billing period;

STANDBY SERVICE RIDER
Schedule SSR (Continued)

RATES: (Continued)

c) Daily Maintenance Demand shall equal the Maximum Maintenance Demand metered during a calendar day; and

d) Monthly Maintenance Demand shall equal the sum of the Daily Maintenance Demands for billing period.

3. For Customers with Standby Contract Capacity greater than 10MW

Terms for service to Distributed Generation systems of this size will be established by special rate and interconnection agreements. Provisions of the special agreements will address all requirements of systems of this size, including the requirements of the Southwest Power Pool and North American Electric Reliability Corporation. The Company may examine the locational benefit of the Customer Distributed Generation system and consider those benefits in defining the rates charged under this Schedule SSR. As practical, the terms of the special agreements will utilize rates and terms defined within the Company's Commission approved tariffs.

GENERAL PROVISIONS:

The contract term shall be one (1) year, automatically renewable, unless modifications to the Distributed Generation requires a change to the Standby Contract Capacity.

For Distributed Generation larger than 2MW, the Company will install and maintain the necessary suitable meters for measurement of service rendered hereunder, including the Metered Grid Interconnection Load and the Metered Generation Output. The Company may inspect generation logs or other evidence that the Customer's Distributed Generation is being used in accordance with the provisions this Schedule SSR. Upon installation of the metering, the Customer shall initially reimburse the Company for any metering investment costs that are in addition to the cost of metering of standard full requirements retail service.

Distributed Generation systems shall not commence parallel operation until after inspection by the Company and a written interconnection agreement is executed.

All metering occurring for service received and billed under this Schedule SSR will be measured in 15-minute intervals.

STANDBY SERVICE RIDER
Schedule SSR (Continued)

GENERAL PROVISIONS: (Continued)

It is expected that the Customer will perform routine and scheduled maintenance of the Distributed Generation systems during the Winter Season.

The Customer is responsible for timely notification of the Company, in writing, if the Distributed Generation system or load curtailment plan is changed in any what that would impact the Standby Contract Capacity. The Company reserves the right to confirm the Standby Contract Capacity at any time.

If at any time Customer desires to increase demand above the capacity of Company's facilities used in supplying said service due to plant modifications, Customer will sign a new agreement for the full capacity of service required and in accordance with applicable rules governing extension of its distribution system.

In the event a Customer adds Distributed Generation systems after investments are made by the Company in accordance with the Company’s Line Extension policy, the Company may require reimbursement by the Customer. Such reimbursement shall be limited to that investment which was incurred within the previous five years and shall be based upon the change in load requirements on the Company’s electric system.

In establishing interconnection agreements, parallel operating guidelines, purchase agreements and standby service arrangements with customers in accordance with 18 C.F.R. Sections 292.101 et seq., it is not the Company's intent to simultaneously sell electricity at system-wide average costs and to re-purchase the same electricity at avoided costs. Any condition which allows for this to occur, potentially or actually,shall not be permitted.

REGULATIONS:

Subject to Rules and Regulations filed with the State Regulatory Commission.

RENEWABLE ENERGY RIDER
Schedule RER

PURPOSE:

This Program is designed to provide non-Residential Customers a voluntary opportunity to purchase Renewable Energy, in addition to service provided through a generally available rate, from Renewable Energy sources that the Company contracts.

Following Commission approval of this Rider, the Company will endeavor to procure the Renewable Energy sources necessary to fulfill Customer requests for service under this Program. Pricing and related terms will be updated to reflect these sources.

AVAILABILITY:

Customer accounts receiving Unmetered, Lighting, Net Metering, or Time-of-Use Service are ineligible for this Program while participating in those service agreements. This Program is not available for resale, standby, breakdown, auxiliary, parallel generation, or supplemental service.

Service under this Program is available on a limited and voluntary basis, at the Company's option, to non-Residential Customers currently receiving permanent electric service from the Company through Schedule SGS, MGS, LGS, SGA, MGA, or LGA, with an annual average monthly peak demand greater than 200 kW. At the Company's sole approval, Customers that have an aggregate electric load of at least 2.5 MW based upon peak annual demand and an average of 200 kW per account, or are recognized by the Company as Governmental or Municipal Customers, may combine separate accounts to participate in this Program.

Customers will be enrolled and subscribed on a first-come, first-served basis. Customers applying but not allowed to subscribe due to Renewable Energy resource unavailability will be placed on a waiting list and may be offered the opportunity to subscribe if subscription cancellations or forfeitures occur. Customers approved for aggregation of accounts may choose to participate in part or remain on the list as a consolidated group, depending on resource availability. Participants may cancel their subscription at any time subject to any net cost of the remaining Renewable Energy for the term. Service hereunder is provided to one end-use Customer and may not be redistributed or resold.

Within any limits prescribed by the individual tariffs, the Company will combine the subscription requirements for all Company jurisdictions in executing the power purchase agreement(s) for the Renewable Energy resource. The combined Program will be initially limited to a minimum total load of 100 megawatts (MW) and a maximum total load of 200 MW, split equally between the Company jurisdictions. The Company reserves the right to reapportion the allocation between Companies in response to Customer subscription. The production from the combined power purchase agreement(s) for the Renewable Energy resource will be allocated among the various Company jurisdictions based on the respective subscriptions within that jurisdiction. The limit will be re-evaluated if or when the 200 MW limit is reached. Additional subscriptions will be made available at the sole discretion of the Company.

RENEWABLE ENERGY RIDER
Schedule RER (Continued)

DEFINITION:

For purposes of this Program the following definitions apply:

1. PARTICIPANT — The Customer, specified as the Participant in the Participant Agreement, is the eligible Customer that has received notification of acceptance into the Program.

2. PARTICIPANT AGREEMENT — The agreement between the Company and Customer, utilized for enrollment and establishing the full terms and conditions of the Program. Eligible Customers will be required to sign the Participant Agreement prior to participating in the Program. This agreement may be provided and executed electronically.

3. POWER PURCHASE AGREEMENT (PPA) — an agreement or contract between a resource owner and the Company for renewable energy produced from a specific renewable resource.

4. RENEWABLE ENERGY CREDITS — also known as Renewable Energy Certificates or RECs, represent the environmental attributes associated with one (1) megawatt-hour of renewable electricity generated and delivered to the power grid.

5. RENEWABLE ENERGY — energy produced from a renewable resource as defined in K.S.A. 66-1257, K.A.R. 82-16-1 (l), and associated with this Program. Renewable resources procured will be utilized for this program or similar voluntary, green programs.

6. RESOURCE PROCUREMENT PERIOD — the period of time in which the Company will, if the subscriptions on the waiting list warrant such effort, attempt to obtain a renewable resource to serve the Participation Agreements queued on the waiting list. At a minimum, two Resource Procurement Periods will occur each calendar year

7. SUBSCRIPTION INCREMENT (SI) — An eligible Customer may subscribe and receive energy from a renewable resource in single percentage increments, up to 100% of the Customer's Annual Usage.

RENEWABLE ENERGY RIDER
Schedule RER (Continued)

DEFINITIONS: (Continued)

8. SUBSCRIPTION SHARE (SS) — The proportion of the renewable resource, adjusted for the Renewable Resource Capacity Factor, allocated to the Customer to achieve the desired Subscription Increment amount. The Subscription Share is determined at enrollment and is calculated using the following formula:

$$\mathrm{SS} = \frac{\mathrm{SL_{MW}}}{\mathrm{RRC_{MW}}}$$

Where,

$$\mathrm{SL_{MW}} = \frac{\mathrm{AU_{MWh}} \cdot \mathrm{SI}}{8{,}760_{\text{hours per year}} \cdot RRC_{factor}}$$

$\mathrm{AU_{MWh}}$ = Annual Usage; the Customer's actual metered energy usage over the previous 12 monthly billing periods, if available, or Customer's expected metered energy usage over 12 monthly billing period as determined by Company.

$\mathrm{RRC_{MW}}$ = Renewable Resource Capacity Factor; the average annual capacity of the renewable resource(s) as established by the Company.

$\mathrm{RRC_{factor}}$ = Renewable Resource Capacity Factor; the average annual capacity factor of the renewable resource(s) as established by Company.

ENROLLMENT:

1. The Customer must submit a completed Participant Agreement to the Company for service under this Program. In the Participant Agreement, the Customer must specify the Subscription Increment to be subscribed.

2. Customers applying for service under this Program must have an account that is not delinquent or in default at the beginning of the Resource Procurement Period and must have completed the required Participant Agreement.

3. Enrollment requests may be submitted to the Company at any time.

4. The Company will review the Participant Agreement and determine if the Customer will be enrolled into the Program.

RENEWABLE ENERGY RIDER
Schedule RER (Continued)

ENROLLMENT: (Continued)

5. In each Resource Procurement Period the Company will match as accurately as possible the combined Renewable Subscription Level of all Participants with a renewable resource, subject to availability. The minimum renewable resource to be acquired will have a capacity of 100 MW and the maximum will depend upon the level of Participation Agreements received. The renewable resource obtained for each Subscriber group may be made up of capacity from multiple renewable resources.

CHARGES AND BILLING:

All charges provided for under, and other terms and conditions of, the Customer's applicable standard service classification(s) tariff shall continue to apply and will continue to be based on actual metered energy use during the Customer's normal billing cycle.

Under this Schedule RER, Customers will receive a Renewable Adjustment (RA), in the form of an additional charge or credit to their standard bill based upon the sale of the metered output of the renewable resource(s) into the wholesale market. The Renewable Adjustment will be calculated as follows:

$$\mathrm{RA} = [\mathrm{RMO}_{\mathrm{MWh}} \cdot \mathrm{SS}] \cdot [\mathrm{SC}_{\$\ \mathrm{per\ MWh}} - \mathrm{FMP}_{\$\ \mathrm{per\ MWh}}]$$

Where,

$\mathrm{RMO}_{\mathrm{MWh}}$ = Metered output from the renewable resource at the market node.

$\mathrm{SC}_{\$\ \mathrm{per\ MWh}}$= Subscription Charge; the delivered price per MWh of the renewable resource plus the Company Administration Charge of $0.10 per MWh (RMO) for twenty-year term Participant Agreements. For all other Participant Agreements, the Company Administration Charge will be $0.30 per MWh (RMO).

$\mathrm{FMP}_{\$\ \mathrm{per\ MWh}}$ = Final Market Price; the accumulation of all applicable market revenues and charges arising from or related to injection of the energy output of the renewable resource into the wholesale energy market in that calendar month at the nearest market node, divided by the actual metered hourly energy production, using the best available data from the regional transmission operator, who facilitates the wholesale marketplace, for the calendar month as of the date the Customer's Renewable Adjustment is being prepared. Alternatively, and at the Company's discretion if determined to be economic, the Company may seek to obtain the necessary transmission to deliver the energy output of the renewable resource to a local, Company market node. If this occurs, the Final Market Price will be calculated based on the accumulation of all applicable market revenues and charges inclusive of this delivery. The energy produced under this alternative will be subject to curtailment by the regional transmission operator. The Final Market Price will be rounded to the nearest cent.

RENEWABLE ENERGY RIDER
Schedule RER (Continued)

CHARGES AND BILLING: (Continued)

The Renewable Adjustment may be applied up to 60 days later than the market transactions to allow for settlement and data processing.

Market revenues and charges may be adjusted to reflect net costs or revenues associated with service under the Program in prior months, for which more recent wholesale market settlement data supersedes the data that was used to calculate initial charges or credits that were assessed to participating Customers.

The Renewable Subscription Charge and the Subscription Share are to be determined at the time the Company obtains the renewable resource to satisfy the Participation Agreement.

Billing and settlement of charges under this Schedule may occur separately from the billing associated with service provided to a Customer's under the Standard Rate Schedules. The Company reserves the right to consolidate account data and process charges collectively to facilitate Customers electing to aggregate subscriptions under this Schedule.

TERM:

Agreements under this Program are available for enrollment for five-year, ten-year, and twenty-year terms. Customers will select the term at time of enrollment and will not be allow to change the term once the renewable resource serving the Customer has been obtained. Customers subscribing to more than 20% of the renewable resource will be required to commit to a minimum term of ten years.

RENEWABLE RESOURCE ENERGY CREDITS:

Renewable Energy Credits associated with energy obtained through this Program will be transferred to the Customer annually or at any time upon Customer request. Alternatively, and if requested, the Company will retire the credits on behalf of the Customer with all costs associated with the registration and retirement borne by the requesting Customer.

RENEWABLE ENERGY RIDER
Schedule RER (Continued)

TRANSFER OR TERMINATION:

Participants who move to another location within the Company's Kansas service territory may request transfer of their subscription, provided the total kWh of the subscribed amount is less than the new location's average annual historical usage (actual or Company estimated). If the existing subscription level exceeds the allowed usage amount at the new location, the subscription will be adjusted down accordingly.

Participants who request termination of the Participation Agreement, or default on the Participation Agreement before the expiration of the term of the Participation Agreement, shall pay to the Company any associated costs and administration associated with termination of the subscribed renewable resource. Such termination charge may be adjusted if and to the extent another Customer requests service under this Schedule and fully assumes the obligation for the purchase of the renewable energy prior to the effective date of the contract amendment or termination; provided, however, Company will not change utilization of its assets and positions to minimize Customer’s costs due to such early termination. The Participant must notify the Company in writing of their request to terminate.

RENEWABLE CONTRACTS SUPPORTING ECONOMIC DEVELOPMENT:

The Company may, at its discretion, enter into an individual agreement with a Customer requesting Renewable Energy to support customer retention or incremental load resulting from the construction or expansion of facilities within the Company's service territory. Depending on the details of the Customer need, the load may be served by the same Renewable Energy resource used for this Program or may result in agreements for additional Renewable Energy resources. The individual terms concerning pricing will be established with the requesting Customer. All agreements are subject to availability and deliverability of Renewable Energy resources and will be structured in such a way as to ensure recovery of all related costs from the requesting Customer.

RENEWABLE ENERGY RIDER
Schedule RER (Continued)

PROGRAM PROVISIONS AND SPECIAL TERMS:

1. In procuring the Renewable Energy, the Company will ensure that Renewable Energy resources utilized under this Program are or have been placed in service after January 1, 2019.

2. At enrollment, the Company will calculate the Customer's demand for the prior twelve-month period to determine eligibility. If twelve months of demand data is not available, the Company may estimate the annual demand to the nearest kW, using a method that includes, but is not limited to, usage by similarly sized properties or engineering estimates.

3. Customers that the Company, at its sole discretion, determines are ineligible will be notified promptly, after such Participant Agreement is denied.

4. Customer participation in this Program may be limited by the Company to balance Customer demand with available qualified Renewable Energy resources, adequate transmission facilities, and capacity.

5. Customers who need to adjust in their commitments due to increases or decreases in electric demand may request such adjustment in writing from the Company. Efforts will be made to accommodate the requested adjustment. The Customer will be responsible for any additional cost incurred to facilitate the adjustment.

6. Any Customer being served or having been served on this Program waives all rights to any billing adjustments arising from a claim that the Customer's service would be or would have been at a lower cost had it not participated in the Program for any period of time.

7. The Company may file a request to discontinue this Program with the Commission at any time in the future. Prior to the termination, the Company will work with the participating Customer to transition them fully from the subscriptions in effect to a Standard Rate Schedule or to an alternate green power option that the Company may be providing at that time. Any Participant who cancels Program participation must wait twelve (12) months after the first billing cycle without a subscription to re-enroll in the Program.

8. Ownership of unsubscribed energy and the associated RECs will be assumed by the Company and incorporated into the energy provided to retail Customers. Unsubscribed amounts will be allocated between the jurisdictions based on the Customer Subscriptions in place at the time of processing.

RENEWABLE ENERGY RIDER
Schedule RER (Continued)

PROGRAM PROVISIONS AND SPECIAL TERMS: (Continued)

9. Ownership of unsubscribed energy and the associated RECs will be assumed by the Company and incorporated into the energy provided to retail Customers. Unsubscribed amounts will be allocated between the jurisdictions based on the Customer Subscriptions in place at the time of processing.

10. The Company shall not be liable to the Customer in the event that the Renewable Energy supplier fails to deliver Renewable Energy to the market and will make reasonable efforts to encourage the Renewable Energy supplier to provide delivery as soon as possible. However, in the event that the Renewable Energy supplier terminates the Renewable Energy contract with the Company, for any reason during the term of contract with the Customers, the Company, at the election of the Customer, shall make reasonable efforts to enter into a new PPA with another Renewable Energy supplier as soon as practicable with the cost of the Renewable Energy to the Customer revised accordingly.

11. Operational and market decisions concerning the renewable resource, including production curtailment due to economic conditions, will be made solely by the regional transmission operator. These decisions could impact the market price received for the renewable resource energy output.

REGULATIONS:

Subject to Rules and Regulations filed with the State Regulatory Commission.

SOLAR SUBSCRIPTION PILOT RIDER
Schedule SSP

PURPOSE:

The purpose of the Solar Subscription Pilot Rider (Program) is to provide a limited number of Customers the opportunity to voluntarily subscribe to the generation output of a solar resource and receive electricity from solar resources. This Program will allow the Company to deploy and evaluate a structure for integrating solar energy directly into service provided to its Customers.

Program Participants will subscribe and pay for Solar Blocks of five hundred (500) watts (W AC) each. Energy produced by the subscribed Solar Blocks will offset an equivalent kWh amount of energy they receive and are billed for under their standard class of service. Approximately 10,000 Solar Blocks will be available for subscription with the initial offering. This program may be expanded to include up to 50 MW of installed solar capacity. Depending on Customer interest, additional solar resources may be built and Solar Blocks made available. Customers will be required to enroll for the Program in advance and each solar resource will be built when 75 percent of the proposed solar resource is committed. If the Company does not receive a sufficient number of subscriptions for the Program, the Company may terminate this Schedule SSP.

AVAILABILITY:

This Rider is available to any Customer currently receiving permanent electric service under the Company's retail rate schedules. Customers must complete the required Participant Agreement and have an account that is not delinquent or in default.

Participants will be enrolled on a first-come, first-served basis. Customers applying but not allowed into the Program due to Solar Block unavailability will be placed on a waiting list and incorporated into the Program in the order they are received. Should Solar Blocks become available due to construction of additional solar resources or subscription cancellations, Customers on the waiting list will be offered the opportunity to subscribe. Subscription hereunder is provided through one meter to one end-use Customer and may not be aggregated, redistributed, or resold.

Total participation of non-residential Customers will be limited to no more than 50 percent of the total solar resource capacity during the first three months of the Program. After three months, and at the Company's sole discretion, all available solar resource capacity may be made available to all eligible Customers.

This Rider may not be combined with any other renewable energy program offered by the Company for the same Customer account.

Customers receiving Unmetered, Lighting, Net Metering, or Time-of-Use Service are ineligible for this Program while participating in those service agreements. This schedule is not available for resale, standby, breakdown, auxiliary, parallel generation, or supplemental service.

SOLAR SUBSCRIPTION PILOT RIDER
Schedule SSP (Continued)

PRICING:

The Solar Block Subscription Charge for energy sold through this Program is $0.14370 per kWh, made up of two costs:

1. The Solar Block cost of $0.11500 per kWh; and
2. The charge of $0.02870 per kWh for interconnection service costs.

The Solar Block cost is defined by the total cost of the solar resources built to serve the program. The interconnection charge is the embedded cost of Transmission and Distribution based on the Company's class cost of service study from the Company's most recent rate case. When an additional solar resource is added to the Program, the levelized cost of the new solar resource will be averaged with the remaining levelized cost of existing solar resource(s) to determine the new price for the cost of the Solar Block. This price may be greater than or less than the previous price. The cost of facilities for distribution interconnection is subject to change in future general rate proceedings, independent from the Solar Block cost.

SUBSCRIPTION LEVEL:

Participants may subscribe to Solar Blocks that, when combined, are expected to generate up to 50 percent of their annual energy. During initial sign-up, the Customer will designate their desired subscription percentage in increments of 10 percent. The Company will provide to the Customer the number of Solar Blocks necessary to supply their subscription percentage based on the Customer's annual energy usage. The Customer's annual energy usage will be determined in one of two ways. If during initial signup the Customer has 12 consecutive months of usage history at the address where the subscription is being requested, then the annual energy will be the energy consumed during that 12-month usage history. If the Customer does not have 12 consecutive months of usage history at the address where the subscription is being requested, then the annual energy will be estimated by the Company. The calculation for the number of Solar Blocks is equal to the annual energy (in kWh) divided by the expected annual energy production of one block rounded down to the lowest whole number. A Customer must have sufficient annual usage to support subscription of at least one Solar Block.

Until the Company expands its solar energy production beyond the initial 5 MW, the maximum amount any one Customer may subscribe to is 2,500 kW AC of capacity. After the expansion of solar energy production, subscription for any one Customer beyond 2,500 kW AC will be at the Company's discretion. A Participant may change their subscription level only once in any 12-month period after the initial 12-month subscription. In the event there is a significant and regular reduction in Participant metered energy consumption, the Company, at its sole discretion, may adjust the Participant's subscription level.

SOLAR SUBSCRIPTION PILOT RIDER
Schedule SSP (Continued)

BILLED PURCHASE QUANTITY:

The quantity of energy that will be purchased by a Participant for each monthly billing cycle will be computed as follows:

$$PQ = \frac{SL}{TSC} \cdot AME$$

Where,

PQ = Monthly Purchase Quantity in kWh

SL = Subscription Level in kW AC

TSC = Total Solar System Capacity in kW AC

AME = Actual Monthly Energy Produced by the Solar Resource in kWh.

The Total System Capacity will be re-determined whenever a new solar facility is brought online or an existing solar facility is taken offline.

MONTHLY BILLING:

1. The monthly energy production of the solar resource will be measured and apportioned to each Participant based on their respective subscription share. To facilitate billing, energy production will be applied to the monthly billing one month after it occurs.
2. The Participants share of the solar resource energy production will be subtracted from the metered energy consumed by the Participant for the billing month. Should the solar resource energy production amount for a given month be larger than the Participant's metered energy consumption, the net energy will be zero for that month.
3. Any remaining metered energy consumption will be billed under the rates associated with the Participant's standard rate schedule, including all applicable riders and charges
4. Other, non-energy charges defined by the standard rate schedule are not impacted by the Solar Block subscription and will be billed to the Participant.
5. The entire bill amount, inclusive of all standard rate charges and Program charges, must be paid according to the payment terms set forth in the Company Rules and Regulations.

SOLAR SUBSCRIPTION PILOT RIDER
Schedule SSP (Continued)

WAITING LIST:

If at the time of subscription request a Customer’s desired subscription level is greater than the available energy of the solar resource, then the Customer may elect to be placed on a waiting list.

Customers will be offered an opportunity to subscribe in the order that they are placed on the waiting list, only if available capacity is greater than the customer’s desired subscription level. If the available capacity is less than the Customer’s desired subscription level, the Customer will be offered the opportunity to subscribe to the remaining available capacity. If the Customer does not wish to participate at this lower than desired subscription level, then the next Customer on the waiting list will be checked for subscription availability.

SUBSCRIPTION TERM:

Participants must remain in the Program for one year, as measured from the first bill received under this Rider.

Non-residential Participants who subscribe to 25 percent of the available Solar Blocks for a given solar resource, are required to commit to a minimum term of five years.

PROGRAM PROVISIONS AND SPECIAL TERMS:

1. All rights to the renewable energy certificates (REC) associated with the generation output of the solar facility will be retired by the Company on behalf of Participants.

2. Any Participant being served or having been served on this Program waives all rights to any billing adjustments arising from a claim that the Participant's service would be or would have been at a lower cost had it not participated in the Program for any period of time.

3. Participants who move to another location within the Company's Missouri service territory may transfer their subscription, provided the total kWhs of the subscribed amount is not more than the new location's allowed subscription level (actual or estimated). If the subscription level exceeds the allowed amount at the new location, the subscription will be adjusted down accordingly.

4. Participants must notify the Company in writing of their intent to transfer any subscription(s). Transfers will only be effective if the Transferee satisfies the terms and conditions applicable to the subscription and signs the Participant Agreement and assumes all responsibilities associated therewith.

SOLAR SUBSCRIPTION PILOT RIDER
Schedule SSP (Continued)

PROGRAM PROVISIONS AND SPECIAL TERMS: (Continued)

5. Customers that subscribe will continue as Participants until they cancel their subscription or the Program is terminated. New subscriptions and cancelations require notice 20 days prior to the end of the Participant's billing cycle and will take effect at the beginning of the next applicable billing cycle.

6. Upon cancelation of a Participant's service, Participants may transfer their entire subscription to another eligible Participant's service agreement, including non-profits, for a $25 fee. Participants with more than one Solar Block may transfer their Solar Block subscriptions in whole subscription increments to one or more Eligible Customers for a $25 fee per transfer.

7. Any Participant who cancels Program participation must wait 12 months after the first billing cycle without a subscription to re-enroll in the Program.

8. Ownership of unsubscribed Solar Blocks and the associated RECs will be assumed by the Company and incorporated into the energy provided to retail Customers.

ADJUSTMENTS AND SURCHARGES:

The Rates hereunder are subject to adjustment as provided in the following schedules:

- Energy Cost Adjustment (ECA)
- Energy Efficiency Rider (EER)
- Property Tax Surcharge (PTS)
- Tax Adjustment (TA)
- Transmission Delivery Charge (TDC)

REGULATIONS:

Subject to Rules and Regulations filed with the State Regulatory Commission.

MUNICIPAL ORNAMENTAL STREET LIGHTING SERVICE
Schedule MOL

AVAILABILITY:

Available for ornamental street lighting service through a Company-owned Street Lighting System within corporate limits of a municipality.

TERM OF CONTRACT:

Contracts under this schedule shall be for a period of not less than ten years from the effective date thereof. Termination prior to end of 10-year period results in a one-time charge equal to the Company's actual investment less depreciation.

RATE: (High Pressure Sodium Vapor) 2MOSL
(Light Emitting Diode (LED)) 2MOLL

1.0 Basic Installation:
Street lamps equipped with ornamental luminaire on ornamental poles served from underground extensions not in excess of 200 feet per unit:

	Size of Lamp	Monthly kWh	Total Charge, per Lamp, per Month, Under Sod	Total Charge, per Lamp, per Month, Under Concrete
1.1	9500 Lumen High Pressure Sodium (100-watt)	49	$64.66	$94.50
1.2	16000 Lumen High Pressure Sodium (150-watt)	67	$65.72	$95.89
1.3	4300 Lumen LED (Class K) (Acorn Style)	26	$61.83	$90.84
1.4	10000 Lumen LED (Class L) (Acorn Style)	41	$62.32	$91.65

Company inventory availability as follows [1,2]:

1. Luminaire: Standard Ornamental
2. Post: 12-foot cast aluminum with 4 inch diameter shaft
3. Base: Standard Screw-in Base

(1) If any equipment becomes obsolete, then new installations will be accomplished with the most appropriate available equipment by mutual agreement of the Company and the Municipality.
(2) Any changes to above listed standard equipment will incur additional monthly facilities charges.

Lumens for LED luminaires may vary ±12% due to differences between luminaire suppliers.

NOTE: Hight Pressure Sodium wattage specifications do not include wattage required for ballast.

OFF-PEAK LIGHTING SERVICE
Schedule LS

AVAILABILITY:

For metered, secondary voltage, electric outdoor lighting service solely to a municipality or governmental entities for purposes of enhancing security and/or illuminating streets, parks, athletic fields, parking lots, or other outdoor facilities. At the Company's discretion, the metering requirement may be eliminated where it is impractical or difficult to install and read meters. Usage for unmetered lights will be estimated using wattage ratings and hours usage. The lamps served under this schedule must be controlled with a photo-electric cell or other positive controlled device which restricts service to non-daylight hours. Governmental entities qualifying for service under this schedule include departments, agencies, and subdivisions of the United States, the State of Kansas, counties, municipalities, and school districts.

Service to privately-owned lights or Company-owned street lights shall not be supplied under this schedule. Standby, breakdown, supplementary, temporary or seasonal service will not be supplied under this schedule.

TERM OF CONTRACT:

Contracts under this schedule shall be for a period of not less than one year from the effective date thereof.

RATE: 2LS1E

$0.05963 per kWh for all kWh per month.

OFF-PEAK LIGHTING SERVICE
Schedule LS (Continued)

RATE: KSOLL, 2LSIE (Unmetered)

1. The Customer will pay a monthly charge for all lighting service as follows:

A.	Customer Charge	$21.70
B.	Energy Charge (All usage)	$0.05963

2. The monthly kWh usage for unmetered service will be calculated as follows:

$$\text{kWh Usage} = \frac{\text{Total Watts } \cdot \text{MBH} \cdot \text{BLF}}{1{,}000}$$

$\text{MBH} =$ Monthly Burning Hours $(\frac{4{,}100\ hours}{12})$
$\text{BLF} =$ Ballast Loss Factor; one (1) plus the manufacturer’s published ballast loss percentage (expressed as a decimal fraction) for the installed unit if applicable.

3. For unmetered service, the Company shall have the right to verify or audit the type, wattage, and number of lights installed.

ADJUSTMENTS AND SURCHARGES:

The rates hereunder are subject to adjustment as provided in the following schedules:

- Energy Cost Adjustment (ECA)
- Property Tax Surcharge (PTS)
- Tax Adjustment (TA)
- Transmission Delivery Charge (TDC)

REGULATIONS:

Subject to Rules and Regulations filed with the State Regulatory Commission.

Issued: May 1, 2018
Month Day Year

Effective: ______
Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

PRIVATE UNMETERED PROTECTIVE LIGHTING SERVICE (FROZEN)
Schedule AL

AVAILABILITY:

For unmetered protective lighting service for private entrances, exits, yards, driveways, streets, alleys, walkways and other all-night outdoor private areas on existing customer's premises. Not available for municipal street, park or other public lighting, or for temporary service.

RATE: 2ALDA, 2ALDE

1. Base Charge:

The monthly rate for each private lighting unit installed on an existing wood pole and using existing secondary circuits is as follows:

	Monthly kWh	Area Lighting	Flood Lighting
5800 Lumen High Pressure Sodium Unit (70-watt)	34	$14.94	
8600 Lumen Mercury Vapor Unit* (175-watt)	71	$15.61	
16000 Lumen High Pressure Sodium Unit (150-watt)	67		$24.76
22500 Lumen Mercury Vapor Unit* (400-watt)	157	$25.17	
22500 Lumen Mercury Vapor Unit* (400-watt)	157		$26.78
50000 Lumen High Pressure Sodium Unit (400-watt)	162		$42.18
63000 Lumen Mercury Vapor Unit* (1000-watt)	372		$45.80

* Limited to the units in service September 30, 1985, until removed.

NOTE: Wattage specifications do not include wattage required for ballast.

2. Additional Charges:

If an extension of the Company's secondary circuit or a new circuit is required either on or off the customer's premises to supply service hereunder at the location or locations desired on the customer's premises, the above monthly rate shall be increased as follows:

Each 30-foot ornamental steel pole installed	$ 11.25
Each 35-foot ornamental steel pole installed	$ 12.35

PRIVATE UNMETERED PROTECTIVE LIGHTING SERVICE (FROZEN)
Schedule AL (Continued)

RATE: 2ALDA, 2ALDE (Continued)

2. Additional Charges: (Continued)

Each 30-foot wood pole installed	$6.96
Each 35-foot wood pole installed	$8.06
Each overhead span of circuit installed	$2.17

If the installation of additional transformer facilities is required to supply service hereunder, the above monthly rate shall be increased by a charge equal to one and three-fourths percent of the Company's total investment in such additional transformer facilities.

If the customer requires underground service, the customer will be responsible for installing all underground ductwork in conformance with Company specifications and the Company will be responsible for installing cable and making the connection to Company facilities. There will be an additional $3.05 per month charge for each underground lighting unit served. If the underground conduit exceeds 300 feet in length, there will be an additional charge of $3.05 per month per 300 foot length, or fraction thereof.

BILLING:

The charges for service under this schedule shall appear as a separate item on the customer's regular electric service bill.

TERM:

The minimum initial term under this rate schedule shall be one year. However, if the private lighting installation requires extension of the Company's service facilities of more than one pole and one span of circuit or the installation by the Company of additional transformer facilities, the customer shall be required to execute a service agreement with an initial term of three years.

UNEXPIRED CONTRACT CHARGES:

If the contracting customer terminates service during the initial term of the agreement, and a succeeding customer does not assume the same agreement for private lighting service at the same service address, the contracting customer shall pay to the Company unexpired contract charges equal to the monthly rate times the number of remaining months in the contract period.

PRIVATE UNMETERED PROTECTIVE LIGHTING SERVICE (FROZEN)
Schedule AL (Continued)

SPECIAL PROVISIONS:

1. The customer shall provide, without cost to the Company, all permits, consents, or easements necessary for the erection, maintenance, and operation of the Company's facilities.

2. The Company reserves the right to restrict installations served under this schedule to areas easily accessible by service truck.

3. All facilities required for service under this schedule will be furnished, owned, installed and maintained by the Company in accordance with the presently effective Construction Standards of the Company.

4. Extension of the Company's secondary circuit under this schedule to more than one pole and one span of wire for service hereunder to any customer is subject to prior study and approval by the Company.

5. The Company will not be obligated to patrol to determine outages or required maintenance of the facilities used for service under this schedule. Upon notification of any outage or required maintenance of facilities used hereunder, the Company will restore normal service as soon as practicable but only during regularly scheduled working hours. No reduction in billing shall be allowed for any outage of less than ten working days after notification of Company.

6. Upon receipt of written request from the customer, the Company will, insofar as it may be practicable and permissible, relocate, replace or change its facilities used or to be used in rendering service to the customer under this schedule, provided the customer agrees in writing to reimburse the Company upon being billed for the Company's cost so incurred.

PRIVATE UNMETERED PROTECTIVE LIGHTING SERVICE (FROZEN)
Schedule AL (Continued)

SPECIAL PROVISIONS: (Continued)

7. If a customer who has agreed to a specific lighting unit requests to change to a different lighting unit, the customer shall pay the labor cost for the removal of the existing unit and the Base Charge for the new unit shall be applicable thereafter.

8. All existing mercury vapor lights shall be changed to high pressure sodium lights when maintenance or change out is required. When these change outs occur, the customer charge will be changed to the high pressure sodium rate.

9. When the Company changes mercury vapor lights, all lights at the same location will be changed to high pressure sodium. The 22500 lumen mercury vapor area light will be retained. However, the customer may change to any other light under Section A.

ADJUSTMENTS AND SURCHARGES:

The rates hereunder are subject to adjustment as provided in the following schedules:

- Energy Cost Adjustment (ECA)
- Property Tax Surcharge (PTS)
- Tax Adjustment (TA)
- Transmission Delivery Charge (TDC)

REGULATIONS:

Subject to Rules and Regulations filed with the State Regulatory Commission.

PRIVATE UNMETERED LED LIGHTING SERVICE
Schedule PL

AVAILABILITY:

For unmetered lighting service for private entrances, exits, yards, driveways, streets, alleys, walkways and other all-night outdoor private areas on existing Customer's premises. Not available for municipal street lighting or for temporary service. Customers will be required to sign an Application for Private Lighting Service before service will be provided.

RATE: 2ALLA, 2ALLE

1. Base Charge:

The monthly rate for each private lighting unit installed using existing secondary circuits is as follows:

	Monthly kWh	Monthly Rate
4,500 Lumen LED (Type A-PAL)	11	$11.01
8,000 Lumen LED (Type C-PAL)	21	$14.40
14,000 Lumen LED (Type D-PAL)	39	$19.06
10,000 Lumen LED (Type C–FL)	27	$14.40
23,000 Lumen LED (Type E–FL)	68	$26.37
45,000 Lumen LED (Type F–FL)	134	$51.53

Lumens for LED luminaires may vary ±12% due to differences between luminaire suppliers.

2. Additional Charges:

Optional Equipment: The following rates for Optional Equipment may be added to the rate for basic installation.

If an extension of the Company's secondary circuit or a new circuit is required either on or off the Customer's premises to supply service hereunder at the location or locations desired on the Customer's premises, the above monthly rate shall be increased as follows:

Each 30-foot metal pole installed (SP30)	$10.94
Each 35-foot metal pole installed (SP35)	$12.01
Each 30-foot wood pole installed (WP30)	$6.77
Each 35-foot wood pole installed (WP35)	$7.84
Each overhead span of circuit installed (SPAN)	$2.11
Optional Breakaway Base (for metal pole only) (BKWY)	$3.48

If the installation of additional transformer facilities is required to supply service hereunder, the above monthly rate shall be increased by a charge equal to one and three-fourths percent (1¾%) of the Company's total investment in such additional transformer facilities.

PRIVATE UNMETERED LED LIGHTING SERVICE
Schedule PL (Continued)

RATE: 2ALLA, 2ALLE (Continued)

2. Additional Charges: (Continued)

If the Customer requires underground service, the Customer will be responsible for installing all underground duct work in conformance with Company specifications and the Company will be responsible for installing cable and making the connection to Company facilities. There will be an additional $2.97 per month charge for each underground lighting unit served up to a maximum of 300 feet of underground conduit per lighting unit (U300).

BILLING:

The charges for service under this schedule shall appear as a separate item on the Customer's regular electric service bill.

TERM:

The minimum initial term under this rate schedule shall be one year for the LED Luminaire. However, if the private lighting installation requires a wood pole or the installation by the Company of additional transformer facilities, the Customer shall be required to execute a service agreement with an initial term of three years. If the Customer wants a metal pole installed, the Customer shall be required to execute a service agreement with an initial term of five years.

UNEXPIRED CONTRACT CHARGES:

If the contracting Customer terminates service during the initial term of the agreement, and a succeeding Customer does not assume the same agreement for private lighting service at the same service address, the contracting Customer shall pay to the Company unexpired contract charges equal to the monthly rate times the number of remaining months in the contract period.

REPLACEMENT OF UNITS:

The Company has the right to replace existing fixtures in need of repair or replacement (or on poles in need of repair or replacement) with equivalent Light Emitting Diode (LED) luminaires. Customers will be given the opportunity to decline the replacement and remove the fixture entirely.

PRIVATE UNMETERED LED LIGHTING SERVICE
Schedule PL (Continued)

SPECIAL PROVISIONS:

1. The Customer shall provide, without cost to the Company, all permits, consents, or easements necessary for the erection, maintenance, and operation of the Company's facilities.

2. The Company reserves the right to restrict installations served under this schedule to areas easily accessible by service truck.

3. All facilities required for service under this schedule will be furnished, owned, installed and maintained by the Company in accordance with the presently effective Construction Standards of the Company.

4. Extension of the Company's secondary circuit under this schedule more than one pole and one span of wire for service hereunder to any Customer is subject to prior study and approval by the Company.

5. The Company will not be obligated to patrol to determine outages or required maintenance of the facilities used for service under this schedule. Upon notification of any outage or required maintenance of facilities used hereunder, the Company will restore normal service as soon as practicable but only during regularly scheduled working hours. No reduction in billing shall be allowed for any outage of less than ten working days after notification of Company.

6. Upon receipt of written request from the Customer, the Company will, insofar as it may be practicable and permissible, relocate, replace or change its non-lighting facilities used or to be used in rendering service to the Customer under this schedule, provided the Customer agrees in writing to reimburse the Company upon being billed for the Company's cost so incurred.

7. If a Customer who has agreed to a specific lighting unit, requests a change to a different lighting unit during the initial term of the contract, the Customer shall pay the labor cost for the removal of the existing unit and the Base Charge for the new unit shall be applicable thereafter.

8. Company shall select style and make of lighting facilities provided within each type system for which rates are listed. Lighting will not be installed on poles or structures not owned or leased by Company.

PRIVATE UNMETERED LED LIGHTING SERVICE
Schedule PL (Continued)

OPERATING HOURS:

Unless otherwise stated, luminaires operate each and every day of the year from about one-half hour after sunset to about one-half hour before sunrise, approximately 4100 hours per year.

ADJUSTMENTS AND SURCHARGES:

The Rates hereunder are subject to adjustment as provided in the following schedules:

- Energy Cost Adjustment (ECA)
- Property Tax Surcharge (PTS)
- Tax Adjustment (TA)
- Transmission Delivery Charge (TDC)

REGULATIONS:

Subject to Rules and Regulations filed with the State Regulatory Commission.

MUNICIPAL STREET LIGHTING SERVICE
Schedule ML

AVAILABILITY:

Available for street lighting service through a Company-owned Street Lighting System within corporate limits of a municipality.

TERM OF CONTRACT:

Contracts under this schedule shall be for a period of not less than ten years from the effective date thereof.

RATE (Incandescent): 2MLIL (FROZEN)

1.0 Street lamps equipped with a hood and reflector, supported on a wood pole or existing trolley pole and supplied from overhead circuits by an extension not in excess of 500 feet per unit: (Code X)

	Size of Lamp	Monthly kWh	Rate per Lamp per Year
1.1	2500 Lumen (187-watt)*	64	$128.88

2.0 Street lamps equipped with a hood, reflector, and refractor, on wood poles served overhead by an extension not in excess of 500 feet per unit: (Code IWT)

	Size of Lamp	Monthly kWh	Rate per Lamp per Year
2.1	4000 Lumen (269-watt)*	92	$218.04
2.2	6000 Lumen (337-watt)*	115	$243.60

*Limited to the units in service on December 28, 1972, until removed.

Issued: May 1, 2018
Month Day Year

Effective:
Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

MUNICIPAL STREET LIGHTING SERVICE
Schedule ML (Continued)

RATE (Incandescent): 2MLIL (FROZEN) (Continued)

3.0 Street lamps equipped with hood, reflector, and refractor, on ornamental steel poles served underground by an extension not in excess of 300 feet per unit:

	Size of Lamp	Monthly kWh	Rate per Lamp per Year
3.1	4000 Lumen (269-watt) Under Sod* (1)	92	$342.12

(1) Code ISE

* Limited to the units in service on December 28, 1972, until removed.

MUNICIPAL STREET LIGHTING SERVICE
Schedule ML (Continued)

RATE (Customer Owned): 2MLCL (FROZEN)

4.0 Street lamps equipped with a hood, reflector, and refractor, owned and installed by customer, maintained and controlled by the Company, served overhead or underground:

	Size of Lamp	Monthly kWh	Rate per Lamp per Year
4.1	16000 Lumen Limited Maintenance (150-watt)[1]	67	$210.60
4.2	27500 Lumen Limited Maintenance (250-watt)[1]	109	$276.00

[1] Code LMX

MUNICIPAL STREET LIGHTING SERVICE
Schedule ML (Continued)

RATE (Mercury Vapor and High Pressure Sodium Vapor): 2MLML, 2MLSK, 2MLSL (FROZEN)

5.0 Basic Installation:
Street lamps equipped with hood, reflector, and refractor, on wood poles served from overhead circuits by an extension not in excess of 200 feet per unit: (Code OW)

	Size of Lamp	Monthly kWh	Lumen Charge per Lamp per Year(1)	Total Charge per Lamp per Year(1)
5.1	8600 Lumen Mercury Vapor (175-watt)*	71	$47.16	$214.08
5.2	12100 Lumen Mercury Vapor (250-watt)*	101	$66.00	$233.04
5.3	22500 Lumen Mercury Vapor (400-watt)*	157	$125.52	$292.56
5.4	5800 Lumen High Pressure Sodium (70-watt)***	34	$33.00	$199.92
5.5	9500 Lumen High Pressure Sodium (100-watt)***	49	$47.52	$214.56
5.6	16000 Lumen High Pressure Sodium (150-watt)***	67	$66.60	$233.64
5.7	27500 Lumen High Pressure Sodium (250-watt)***	109	$125.88	$292.92
5.8	50000 Lumen High Pressure Sodium (400-watt)***	162	$293.88	$460.80

(1)Rates above are based on a Base Unit Charge of $167.04 plus a Lumen Charge as stated above. Twin units will be billed at one and one-half (1 1/2) times the Base Unit Charge plus (2) times the appropriate Lumen Charge. KWh usage for twin lamps is two times the single monthly kWh.

6.0 Optional Equipment: The following rates for Optional Equipment shall be added to the rate for Basic Installation listed in 8.0 above for Mercury Vapor and High Pressure Sodium Vapor installations only.

6.1 Ornamental steel pole instead of wood pole, additional charge per unit per year $46.68. (New installations are available with underground service only).

6.2 Laminated wood pole instead of wood pole.** (Available with underground service only). Additional charge per unit per year $97.92.

6.3 Aluminum pole instead of a wood pole, additional charge per unit per year $95.76. (Available with underground service only).

NOTE: Wattage specifications do not include wattage required for ballast

* Limited to the units in service on April 18, 1992, until removed.
** Limited to the units in service on December 1, 2010, until removed.
*** Limited to units in service on XXXXXXXX XX, XXXX until removed.

MUNICIPAL STREET LIGHTING SERVICE
Schedule ML (Continued)

RATE (Mercury Vapor and High Pressure Sodium Vapor): 2MLML, 2MLSK, 2MLSL (FROZEN) (Continued)

6.4 Underground service extension, under sod, not in excess of 200 feet. Additional charge per unit per year $81.96.

6.5 Underground service extension under concrete, not in excess of 200 feet. Additional charge per unit per year $444.00.

6.6 Breakaway base. Additional charge per unit per year $42.96. (Available with underground service only).

6.7 Special black square luminaire,* instead of basic installation luminaire. (Available with underground service only). Additional charge per unit per year $94.32.

RATE (LED): 2MLLL

7.0 Basic Installation:
Street luminaires on new wood poles serviced from overhead circuits by a new extension not in excess of 200 feet per unit: (Code OW)

	Size and Type of Luminaire–	Monthly kWh	Rate per Luminaire per Month(2) (3)
7.1	5000 Lumen LED (Class A)(Type V pattern)(1)	16	$16.20
7.2	5000 Lumen LED (Class B)(Type II pattern)(1)	16	$16.20
7.3	7500 Lumen LED (Class C)(Type III pattern)(1)	23	$18.93
7.4	12500 Lumen LED (Class D)(Type III pattern)(1)	36	$23.73
7.5	24500 Lumen LED (Class E)(Type III pattern)(1)	74	$25.36

(1) Lumens for LED luminaires may vary ±12% due to differences between lamp suppliers.
(2) Twin luminaires shall be two times the rate per single luminaire per month.
(3) Existing LED luminaires installed under the MARC Pilot (Schedule ML-LED) will be converted to these rates based on their installed lumen size.

* Limited to the units in service on December 1, 2010, until removed.

MUNICIPAL STREET LIGHTING SERVICE
Schedule ML (Continued)

RATE (LED): 2MLLL (Continued)

8.0 Street luminaires on short bracket arm and existing wood poles served from existing overhead circuits: (Code EW)

	Size and Type of Luminaire–	Monthly kWh	Rate per Luminaire per Month
8.1	5000 Lumen LED (Class A)(Type V pattern)[(1)]	16	$16.20
8.2	5000 Lumen LED (Class B)(Type II pattern)[(1)]	16	$16.20
8.3	7500 Lumen LED (Class C)(Type III pattern)[(1)]	23	$18.93
8.4	12500 Lumen LED (Class D)(Type III pattern)[(1)]	36	$23.73
8.5	24500 Lumen LED (Class E)(Type III pattern)[(1)]	74	$25.36

[(1)]Lumens for LED luminaires may vary ±12% due to differences between lamp suppliers.

9.0 Optional Equipment: The following rates for Optional Equipment shall be added to the rate for Basic Installation listed in 10.0 above.

9.1 Metal pole instead of wood pole, additional charge per unit per month $3.78. (New installations are available with underground service only).

9.2 Underground service extension, under sod, not in excess of 200 feet. Additional charge per unit per month $6.64.

9.3 Underground service extension under concrete, not in excess of 200 feet. Additional charge per unit per month $35.95.

9.4 Rock Removal or other specialized trenching/boring for installation of underground service. Additional charge per service per month $20.00.

9.5 Breakaway base. Additional charge per unit per month $3.48. (Available with underground service on metal poles only).

10.0 Special Mounting Heights: The standard mounting height is 31 ft. or less. The following rates for Special Mounting Heights may be added to the rate for new, basic installations listed in section 7.0.

		Wood Pole	Metal Pole
10.1	Between 31 and 41 ft.	$2.13	$3.38
10.2	Greater than 41 ft.	$4.49	$7.89

MUNICIPAL STREET LIGHTING SERVICE
Schedule ML (Continued)

REPLACEMENT OF UNITS:

Existing street lamps shall be replaced at the same pole location with a different type of standard unit installation only by mutual agreement of the Company and the Municipality. The Company has the right to replace existing incandescent, mercury vapor, and high pressure sodium vapor street lamps in need of repair or replacement (or on poles in need of repair or replacement) with equivalent LED high pressure sodium vapor street lamps.

STANDARD UNITS:

Standard street lamps are those LED units for which a rate is stated except those with an X designation in the type code.

BURNING HOURS:

Unless otherwise stated, lamps are to burn each and every day of the year from one-half hour after sunset to one-half hour before sunrise, approximately 4100 hours per year.

ADJUSTMENTS AND SURCHARGES:

The rates hereunder are subject to adjustment as provided in the following schedules:

- Energy Cost Adjustment (ECA)
- Property Tax Surcharge (PTS)
- Tax Adjustment (TA)
- Transmission Delivery Charge (TDC)

REGULATIONS:

Subject to Rules and Regulations filed with the State Regulatory Commission.

MUNICIPAL TRAFFIC CONTROL SIGNAL SERVICE
Schedule TR

AVAILABILITY:

Available for traffic control signal service through a Company-owned Traffic Control System within corporate limits of a municipality.

TERM OF CONTRACT:

Contracts under this schedule shall be for a period of not less than ten years from the effective date thereof.

RATE: Basic Installations 2TSLM

1. Individual Control. This basic installation consists of four mounted 3-light signal units all with 8-inch lenses, and is operated by its own controller (having no more than fourteen signal circuits), which is activated by a synchronous motor. The monthly rate for this basic installation is $169.84 The monthly kWh is 213 kWh.

MUNICIPAL TRAFFIC CONTROL SIGNAL SERVICE
Schedule TR (Continued)

RATE: Basic Installations 2TSLM (Continued)

2. Flasher Control.

A. 1-Way, 1-Light Signal Unit. This basic installation consists of one 1-light signal unit with an 8-inch lens mounted on an existing post, with the traffic signal lamp flashing alternately "on" and "off" 24 hours per day. The monthly rate for this basic installation is 40.09. The monthly kWh is 50 kWh.

B. 4-Way, 1-Light Signal Unit - Suspension. This basic installation consists of four 1-light signal units all with 8-inch lenses mounted by pipe fittings with the entire assembly suspended from an overhead messenger or from a mast arm with a minimum clearance distance of 15 feet above the roadway. The installation is operated by an individual flashing contactor which is activated by a synchronous motor. The monthly rate for this basic installation is 49.95. The suspension system for this signal unit is provided for under Supplemental Equipment, Mast Arm, Wood Pole, Suspension or Steel Pole Suspension. The monthly kWh is 101 kWh.

3. Pedestrian Push Button Control.

This basic installation consists of two 3-light signal units for vehicular control, two 2-light signal units for pedestrian control all with 8-inch lenses, a pair of push buttons for pedestrian actuation, a controller, and a flashing device. The monthly rate for this basic installation is 142.55. The monthly kWh is 221 kWh.

MUNICIPAL TRAFFIC CONTROL SIGNAL SERVICE
Schedule TR (Continued)

RATE: Basic Installations 2TSLM (Continued)

4. Four-and Eight-Phase Electronic Control. This basic installation consists of a pad mounted four-phase or eight-phase electronic controller complete with cabinet, power supply and load relays; additional equipment as required, and all necessary interconnecting cables. This basic installation is available only to intersections where such basic installation is completed and operating after September 30, 1985. The monthly rate for this basic installation is as follows:

A.	Four-phase electronic controller	$510.94
B.	Eight-phase electronic controller	$587.23
C.	Eight-phase electronic controller with pre-empt capabilities	$695.45

The monthly kWh is 55 kWh.

MUNICIPAL TRAFFIC CONTROL SIGNAL SERVICE
Schedule TR (Continued)

RATE: Supplemental Equipment 2TSLM

5. 3-Light Signal Unit. This supplemental equipment consists of one 3-light signal unit with 8-inch lenses installed at any controlled intersection where the 3-light signal unit can be connected to the existing control cable and controller at such intersection. The monthly rate for this supplemental equipment is $24.42. The monthly kWh is 50 kWh.

   This supplemental equipment can be used with the basic 4-Way 3-Light Suspension Control Signal Unit only if the signal units are hung on the same suspension system as the initial units.

MUNICIPAL TRAFFIC CONTROL SIGNAL SERVICE
Schedule TR (Continued)

RATE: Supplemental Equipment 2TSLM (Continued)

6. 2-Light Signal Unit. This supplemental equipment consists of one 2-light signal unit with 8-inch lenses installed at any controlled intersection where the 2-light signal unit can be connected to the existing control cable and controller at such intersection. The 2-light signal unit may have one lens worded "Walk" and the other lens worded "Wait", if specified by the customer. The monthly rate for this supplemental equipment is $23.48. The monthly kWh is 50 kWh.

7. 1-Light Signal Unit. This supplemental equipment consists of one 1-light signal with an 8-inch lens installed as an addition to an existing signal unit at any controlled intersection where the 1-light signal unit can be connected to the existing control cable and controller at such intersection. The monthly rate for this supplemental equipment is $7.20. The monthly kWh is 50 kWh.

8. Push Buttons, Pair. This supplemental equipment consists of a pair of push buttons for pedestrian actuation which may be installed as pedestrian actuation devices at a basic Individual Control installation where Treadle Detectors or Loop Detectors are used or as additional stations at a basic Pedestrian Push Button Control installation and which can be connected to the existing control cable and controller at such installation and operated by the existing controller at such installation by the addition of necessary cams and relays. The monthly rate for this supplemental equipment is $3.26.

9. 12-Inch Round Lens. This supplemental equipment consists of a 12- inch diameter round lens and one 116-watt traffic signal type lamp which are substituted for an 8-inch lens and one 69-watt lamp. The monthly rate for this supplemental equipment is $5.68. The monthly kWh is 48 kWh.

10. 12-Inch Square Lens. This supplemental equipment consists of a 12-inch square lens and one 116-watt traffic signal type lamp which are substituted for an 8-inch lens and one 69-watt lamp. The monthly rate for this supplemental equipment is $9.09. The monthly kWh is 66 kWh.

MUNICIPAL TRAFFIC CONTROL SIGNAL SERVICE
Schedule TR (Continued)

RATE: Supplemental Equipment 2TSLM (Continued)

11. 9-Inch Square Lens. This supplemental equipment consists of a 9-inch square lens and one 116-watt traffic signal type lamp which are substituted for an 8-inch lens and one 69-watt lamp. The monthly rate for this supplemental equipment is $6.37. The monthly kWh is 50 kWh.

12. Fiber Optic Arrow Lens. This supplemental equipment consists of an arrow-forming series of apertures powered by two 42-watt lamps which supply illumination to such apertures by means of optic fibers. The monthly rate for this supplemental equipment is $36.34. The monthly kWh is 50 kWh.

13. Directional Louvre. This supplemental equipment consists of one special 8-inch or 12-inch directional louvre visor which is substituted for one standard visor. The monthly rate for this supplemental equipment is $1.48.

14. Vehicle - Actuation Units.

    A. Loop Detector.

        a) Single. This supplemental equipment consists of one loop detector and one loop installed in the pavement so that vehicles passing over the loop operate the controller at the intersection. The monthly rate for this supplemental equipment is $30.03. The monthly kWh is 15 kWh.

        b) Double. This supplemental equipment consists of one loop detector and two loops installed in the pavement so that vehicles passing over the loops operate the controller at the intersection. The monthly rate for this supplemental equipment is $47.61. The monthly kWh is 18 kWh.

MUNICIPAL TRAFFIC CONTROL SIGNAL SERVICE
Schedule TR (Continued)

RATE: Supplemental Equipment 2TSLM (Continued)

15. Flasher Equipment. This supplemental equipment consists of the necessary clock-controlled flasher equipment so that all signals at a controlled intersection may flash amber to traffic on the main street and flash red to traffic on the cross street during certain preset periods of time. The monthly rate for this supplemental equipment is $8.69. The monthly kWh is 14 kWh.

16. Mast Arm.

    A. Style 2. This supplemental equipment consists of a steel mast arm not to exceed 30 feet in length supported on a steel pole which may or may not also support a street lighting unit. The pole and mast arm shall be of a "classic" style with standard mast arm lengths of 15, 20, 25 or 30 feet, providing a minimum clearance for the traffic signal unit of 15 feet above the street. The monthly rate for this supplemental equipment, including pole, one mast arm, wiring cable, and traffic signal unit attachments, but excluding traffic signal unit, is $38.97.

    B. Style 3. This supplemental equipment consists of a steel mast arm over 30 feet but not to exceed 38 feet in length, supported on a steel pole which may or may not also support a street lighting unit. The pole and mast arm shall be of a "classic" style with standard mast arm lengths of 35 and 38 feet, providing a minimum clearance for the traffic signal unit of 15 feet above the street. The monthly rate for this supplemental equipment, including pole, one mast arm, wiring cable and traffic signal unit attachments, but excluding traffic signal unit, is $39.27.

    C. Style 4. This supplemental equipment consists of a steel mast arm 40 feet or more in length, supported on a steel pole which may or may not also support a street lighting unit. The pole and mast arm shall be of a "classic" style. The mast arm shall provide a minimum clearance for the traffic signal unit of 15 feet above the street. The monthly rate for this supplemental equipment, including pole, one mast arm, wiring cable and traffic signal unit attachments, but excluding traffic signal unit, is $53.05.

MUNICIPAL TRAFFIC CONTROL SIGNAL SERVICE
Schedule TR (Continued)

RATE: Supplemental Equipment 2TSLM (Continued)

17. Back Plate. This supplemental equipment consists of one back plate mounted behind a single head to extend 8 inches beyond the signal in all directions. The monthly rate for this supplemental equipment is $1.76.

18. Wood Pole Suspension. This supplemental equipment consists of two wood poles, necessary guys and span cable to support suspension type traffic signal installations. The monthly rate for this supplemental equipment is $18.51.

19. Traffic Signal Pole. This supplemental equipment consists of a steel pole or an aluminum pole that is no more than 15 feet in length. The monthly rate for this supplemental equipment is $12.71 for each pole.

MUNICIPAL TRAFFIC CONTROL SIGNAL SERVICE
Schedule TR (Continued)

RATE: Supplemental Equipment 2TSLM (Continued)

20. Preemption Control for Emergency Equipment. This supplemental equipment consists of an activation switch, interconnecting cable, and an interface with the traffic signal controller that allows emergency vehicles to preempt the normal signal sequence. The activation switch is located in a fire station or other emergency facility. The monthly rate for this supplemental equipment is $55.37. Availability of this rate is subject to the discretion of the Company.

21. Optically Activated Traffic Signal Priority Control System. This supplemental equipment consists of one D harness and preempt panel, one phase selector, required optical detectors, one interface card rack, optical detector cable of up to 1000 feet in length, mounting brackets, and system control software. This equipment provides optically activated priority control over the traffic signals in one intersection. The monthly rate for this system is $163.27 for each intersection. The system is activated remotely with a data encoded emitter that is installed on emergency vehicles. Customers are responsible for the purchase and installation of all data encoded emitters used on the customers' emergency vehicles, so the cost of such emitters is not included in the above monthly rate. Additionally, the cost of any upgrades of existing equipment necessitated by installation of this system is not included in the rate. The monthly kWh is 20 kWh.

22. Audio Warning Systems for the Visually Impaired. For each intersection including the described supplemental equipment, the customer will be billed one of the following rates:

    A. Rate A: For a Standard Intersection consisting of 4 street corners with crossings in 2 directions from each corner:

        a) 8 Navigator pedestrian push button stations using 2-wire technology, with 5" x 7" international walking signs, with Braille inscriptions on the push button units.
        b) 1 Central control unit mounted in the cabinet.

    The monthly rate for this system is $356.55 per intersection. The monthly kWh is 87 kWh.

    B. Rate B: For Non-Standard Intersections:

    The monthly rate is $169.25 for the central control unit plus $23.42 per each required station using 2-wire technology, 5" x 7" signs and Braille inscriptions. The monthly kWh is 29 kWh for the central control unit and 7 kWh for each station.

Additionally, the cost of any upgrades of existing equipment necessitated by installation of a system must be paid.

MUNICIPAL TRAFFIC CONTROL SIGNAL SERVICE
Schedule TR (Continued)

RATE: Supplemental Equipment 2TSLM (Continued)

23. Camera Video Detection System. For each standard intersection including the described supplemental equipment, the customer will be billed the shown rate:

For a Standard Intersection consisting of 4 directional traffic flows:

A. 4 Image sensors (cameras) with luminaire arm mounting bracket.
B. 4 Image sensor harnesses.
C. 1 Interface panel.
D. 1 Detector port master with harness.
E. Plus required cable and software package.

The monthly rate for this system is $1,100.27 per intersection. The monthly kWh is 26 kWh.

Additionally, the costs of any upgrades of existing equipment necessitated by installation of a system must be paid.

The monthly rates for each type of Supplemental Equipment at an intersection are in addition to the monthly rate for the Basic Installation at that intersection.

ADJUSTMENTS AND SURCHARGES:

The rates hereunder are subject to adjustment as provided in the following schedules:

- Energy Cost Adjustment (ECA)
- Property Tax Surcharge (PTS)
- Tax Adjustment (TA)
- Transmission Delivery Charge (TDC)

REGULATIONS:

Subject to Rules and Regulations filed with the State Regulatory Commission.

THERMAL STORAGE RIDER
Schedule TS

AVAILABILITY:

This Rider shall be available to all customers with installations of Thermal Storage Systems of a size and design approved by the Company who are currently receiving or have requested service under any of the following rate schedules: SGS, MGS, LGS, SGA, MGA, or LGA.

DETERMINATION OF DEMAND:

For customers with Thermal Storage Systems the Monthly Maximum Demand for any month included in the summer season, shall be the highest demand indicated in any 30-minute interval in that month during the period noon to 8 p.m., Monday through Friday (except holidays). Week-day holidays are Memorial Day, Independence Day and Labor Day. All other terms and conditions of the Customer's service schedule shall continue.

METERING:

The Company has the right to submeter the demand and usage of the thermal storage system.

TERMINATION:

Termination of service under this rider shall occur if the customer discontinues operation of the Thermal Storage System.

Real-Time Pricing (FROZEN)
Schedule RTP

CANCELLED

Real-Time Pricing (FROZEN)
Schedule RTP (continued)

CANCELLED

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Month Day Year

Effective:
Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

Real-Time Pricing (FROZEN)
Schedule RTP (Continued)

CANCELLED

THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 79

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 79 Sheet 4

Rate Areas No. 2 & 4
(Territory to which schedule is applicable)

which was filed September 10, 2015

No supplement or separate understanding
shall modify the tariff as shown hereon.

Sheet 4 of 5 Sheets

Real-Time Pricing (FROZEN)
Schedule RTP (Continued)

CANCELLED

Issued: May 1, 2018 (Month Day Year)	
Effective: (Month Day Year)	
By: /s/ Darrin R. Ives, Vice President (Title)	

THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 79

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 79 Sheet 5

Rate Areas No. 2 & 4
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Real-Time Pricing (FROZEN)
Schedule RTP (Continued)

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By: /s/ Darrin R. Ives Vice President
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Real-Time Pricing (FROZEN)
Schedule RTP-Plus

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Real-Time Pricing (FROZEN)
Schedule RTP-Plus (continued)

CANCELLED

THE STATE CORPORATION COMMISSION OF KANSAS

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)
Rate Areas No. 2 & 4
(Territory to which schedule is applicable)

SCHEDULE 80

Replacing Schedule 80 Sheet 3

which was filed September 10, 2015

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Sheet 3 of 5 Sheets

Real-Time Pricing (FROZEN)
Schedule RTP-Plus (Continued)

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By: /s/ Darrin R. Ives Vice President
Title

Real-Time Pricing (FROZEN)
Schedule RTP-Plus (Continued)

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THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 80

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 80 Sheet 5

Rate Areas No. 2 & 4
(Territory to which schedule is applicable)

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Sheet 5 of 5 Sheets

Real-Time Pricing (FROZEN)
Schedule RTP-Plus (Continued)

CANCELLED

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By: /s/ Darrin R. Ives Vice President
Title

MUNICIPAL STREET LIGHTING SERVICE
LIGHT EMITTING DIODE PILOT PROGRAM
Schedule ML-LED

RATE (LED): 2MLLL

The rates charged for 10.1 and 10.2 below are exclusively for the purposes of the Pilot Project and are not reflective of rates that may be associated with a LED lighting schedule upon completion of pilot period study. An LED lighting rate may be developed based on the outcome of this pilot and or other relevant information.

10.0 Basic Installation:
Street lamps equipped with hood, reflector, and refractor, on wood poles serviced from overhead circuits by an extension not in excess of 200 feet per unit: (Code OW)

	Size of Lamp	Monthly kWh	Lumen Charge per Lamp per Year(1)	Total Charge per Lamp per Year(1)
10.1	Small LED (≤ 7000 lumens)	21	$23.40	$190.44
10.2	Large LED (> 7000 lumens)	44	$50.76	$217.68

(1)Rates above are based on a Base Unit Charge of $167.04 plus a Lumen Charge as stated above. Twin units will be billed at one and one-half (1 1/2) times the Base Unit Charge plus (2) times the appropriate Lumen Charge. KWh usage for twin lamps is two times the single monthly kWh.

11.0 Optional Equipment: The following rates for Optional Equipment shall be added to the rate for Basic Installation listed in 10.1 and 10.2 above for LED installations only.

11.1 Ornamental steel pole instead of wood pole, additional charge per unit per year $46.68. (New installations are available with underground service only).

11.2 Aluminum pole instead of a wood pole, additional charge per unit per year $95.76. (Available with underground service only).

11.3 Underground service extension, under sod, not in excess of 200 feet. Additional charge per unit per year $81.96.

11.4 Underground service extension under concrete, not in excess of 200 feet. Additional charge per unit per year $444.00.

11.5 Breakaway base. Additional charge per unit per year $42.96. (Available with underground service only).

GENERAL RULES AND REGULATIONS APPLYING TO ELECTRIC SERVICE (Continued)

1. DEFINITIONS (Continued)

1.10 CUSTOMER'S INSTALLATION:
All wiring, appliances and apparatuses of every kind and nature on the Customer's premises, on the Customer's side of the point of delivery (except the Company's meter installation), used or useful by the Customer in connection with the receipt and utilization of electric service supplied by the Company.

1.11 POINT OF DELIVERY:
The point at which the Company's conductors and/or equipment (other than the Company's meter installation) make electrical connection with the Customer's installation, unless otherwise specified in the Customer's service agreement. Examples of typical meter configurations depicting the point of delivery can be found in the Company’s Construction Standards at www.kcpl.com.

1.12 METER INSTALLATION:
The meter or meters, together with auxiliary devices, if any, constituting the complete installation needed by the Company to measure the class of electric service supplied to a Customer at a single point of delivery.

1.13 MONTH:
An interval of approximately thirty (30) days, unless specified or appearing from the context to be a calendar month.

1.14 SERVICE AGREEMENT:
The application, agreement or contract, expressed or implied, pursuant to which the Company supplies electric service to the Customer.

1.15 ADULT:
One who has reached the legal age of majority, generally 18 years.

1.16 BILLING ERROR:
The incorrect billing of an account due to a Company or Customer meter reading error, which results in incorrect charges.

1.17 FIELD ERROR:
Shall be considered to include lost/mishandled paperwork, installing metering incorrectly, or failure to close the meter potential or test switches. A Field Error may result in a Billing Error.

GENERAL RULES AND REGULATIONS
APPLYING TO ELECTRIC SERVICE (continued)

APPENDIX A (continued)
AGREEMENTS (continued)

(3) PRIVATE, UNMETERED, PROTECTIVE LIGHTING SERVICE INSTALLATION

The Company may enter into agreements with customers or prospective customers as needed to complete requests for service. These requests will take various forms depending on the type of service requested. All agreements will be consistent with terms and conditions of Kansas law and the Company's Commission approved tariffs and regulations.

GENERAL RULES AND REGULATIONS

CANCELLED

THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE TOC-1

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule TOC-1 Sheet 1

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Rate Areas No 2 & 4
(Territory to which schedule is applicable)

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~~Parallel Generation Contract Service~~		
Energy Efficiency, Demand Response, & Customer Programs		

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By: /s/ Darrin R. Ives Vice President
Title

THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE TOC-1

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule TOC-1 Sheet 2

Rate Areas No 2 & 4
(Territory to which schedule is applicable)

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THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE TOC-1

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule TOC-1 Sheet 3

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(Territory to which schedule is applicable)

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~~8~~	~~Building Operator Certification Program~~	~~BOC~~
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~~10~~	~~Property Tax Surcharge~~	~~PTS~~
~~11~~	~~Residential Service~~	~~R~~

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THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE TOC-1

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule ____ Sheet ____

Rate Areas No. 2 & 4
(Territory to which schedule is applicable)

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Title

THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 2

KANSAS CITY POWER & LIGHT COMPANY

(Name of Issuing Utility)

Replacing Schedule 2 Sheet 1

Rate Areas No 2 & 4

(Territory to which schedule is applicable)

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ENERGY COST ADJUSTMENT

Schedule ECA

APPLICAB LITY:

This Energy Cost Adjustment (ECA) Schedule shall be applicable to all Kansas Retail Rate Schedules for KCPL.

BASIS:

Energy costs will be measured and applied to a customer's bill using an ECA factor. The ECA factor is applied on a kilowatt-hour basis ($/kWh). Retail customer charges for energy costs are determined by multiplying the kilowatt-hours of electricity during any calendar month by the corresponding ECA factor for that calendar month.

ENERGY COST ADJUSTMENT:

Prior to January 1 of each ECA year, an ECA factor (ECA_P) will be calculated for each calendar month of the ECA year as follows:

$$ECA_P = \frac{((F_P + P_P + E_P) - BPR_P)}{S_P} - \frac{OSSM_K}{S_K} - \frac{TRUE_A}{S_{TRUE}}$$

Where:

F_P = Projected cost of nuclear and fossil fuel to be consumed for the generation of electricity during the month in which the ECA is in effect for all KCPL Retail, Requirements Sales for Resale, and Bulk Power Sales customers not included in OSSM, to be recorded in Account 501, Account 518 and Account 547, excluding any KCPL internal labor cost.

P_P = Projected cost of purchased power during the month in which the ECA is in effect for all KCPL Retail, Requirements Sales for Resale, and Bulk Power Sales customers not included in OSSM, to be recorded in Account 555, and KCPL's projected charges or credits incurred due to participation in markets associated with Regional Transmission Organizations (RTOs) excluding amounts associated with portions of purchased power agreements dedicated to specific customers under the Renewable Energy Rider tariff.~~.~~

E_P = Projected cost of emission allowances during the month in which the ECA is in effect for all KCPL Retail, Requirements Sales for Resale, and Bulk Power Sales customers not included in OSSM, to be recorded In Account 509.

BPR_P = Projected Revenue from asset-based Bulk Power Sales customers not included in OSSM.

S_P = Projected kWhs to be delivered to all KCPL Retail and Requirements Sales for Resale customers during the month in which the ECA is in effect.

OSSM = Projected annual asset-based Off-System Sales Margin from Bulk Power Sales at the median for the effective ECA year, but excluding: (1) amounts associated with portions of purchased power agreements dedicated to specific customers under the Renewable Energy Rider tariff and (2) amounts associated with generation assets dedicated to specific customers under the Renewable Energy Rider tariff.~~.~~

$OSSM_K$ = The projected annual asset-based Off-System Sales Margin from Bulk Power Sales at the median for the effective ECA but excluding: (1) amounts associated with portions of purchased power agreements dedicated to specific customers under the Renewable Energy Rider tariff and (2) amounts associated with generation assets dedicated to specific customers under the Renewable Energy Rider tariff year multiplied by the projected Unused Energy (UE1) Allocator for Kansas.~~.~~

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S_K = Projected annual kWhs to be delivered to all Kansas Retail customers during the effective ECA year.

S_{TRUE} = Projected kWhs for Kansas Retail customers for the twelve-month period beginning in April of the year following the ECA year

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By: /s/ Darrin R. Ives Vice President (Title)

THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 2

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)
Rate Areas No 2 & 4
(Territory to which schedule is applicable)

Replacing Schedule 2 Sheet 2

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ENERGY COST ADJUSTMENT
Schedule ECA

$TRUE_A$ = The annual true-up amount for an ECA year, to be calculated by March 1 of the year following the ECA year and to be applied for a twelve-month period beginning April 1 of the year following he ECA year. The true-up amount will reflect any difference between the total ECA revenue for he Retail sales during the ECA year and the actual costs incurred to achieve those Retail sales less the credits applied for Off-System Sales Revenue for the ECA year. Such true-up amount may be posi ive or negative. Any remaining balances from prior true-up periods will be added.

$$TRUE_A = ECAREV_A - [((F_A + P_A + E_A - BPR_A) - NABPC_A) \times \frac{S_{AK}}{S_{AT}}] + OSSM_A + TRUE_{PRIOR}$$

Where:

$ECAREV_A$ = Actual ECA revenue for Kansas Retail sales during the ECA year.

F_A = Actual total company cost of nuclear and fossil fuel consumed for the genera ion of electricity for the ECA year recorded in Account 501, Account 518 and Account 547, excluding any internal KCPL labor cost and all costs associated with $OSSM_A$.

P_A = Actual total company cost of purchased power incurred during he ECA year recorded in Account 555, and KCPL's actual charges or credits incurred due to participation in markets associated with Regional Transmission Organizations (RTOs) less all costs associated with $OSSM_A$ excluding amounts associated with portions of purchased power agreements dedicated to specific customers under the Renewable Energy Rider tariff.~~.~~

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E_A = Actual total company emission allowance costs incurred during the ECA year recorded in Account 509 less all costs associated with $OSSM_A$.

BPR_A = Actual Revenue from asset-based Bulk Power Sales customers not included in $OSSM_A$, but excluding: (1) amounts associated with portions of purchased power agreements dedicated to specific customers under the Renewable Energy Rider tariff; and (2) amounts associated with generation assets dedicated to specific customers under he Renewable Energy Rider tariff.~~.~~

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$NABPC_A$ = Actual total company cost for non-asset-based sales to Bulk Power customers during the ECA year, as reflected in P_A,.

$OSSM_A$ = Actual total company asset-based Off-System Sales Margin from Bulk Power Sales for the ECA but excluding: (1) amounts associated with portions of purchased power agreements dedicated to specific customers under the Renewable Energy Rider tariff; and (2) amounts associated with generation assets dedicated to specific customers under the Renewable Energy Rider tariff year —multiplied by he actual Unused Energy (UE1) Allocator for Kansas.

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S_{AK} = Actual kWhs delivered to KCPL's Kansas Retail customers during he ECA year.

S_{AT} = Actual kWhs delivered to all KCPL Retail and Requirements Sales for Resale customers during the ECA year.

$TRUE_{PRIOR}$ = Remaining true-up amounts from previous ECA years (positive or negative).

Issued: May~~September~~ 1~~0~~, 2018~~5~~
Month Day Year

Effective: ~~October 1, 2015~~
Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 11

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 11 Sheet 2

Rate Areas No 2 & 4
(Territory to which schedule is applicable)

which was filed June~~September~~ 21~~0~~, 2017~~5~~

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 2 of 4 Sheets

RESIDENTIAL SERVICE
Schedule R (Continued)

RATE:

Single-phase kWh and three-phase kWh will be cumulated for billing under this schedule.

1~~A~~. RESIDENTIAL GENERAL USE – ONE METER: 2RS1A, 2RSDA

For general residential use including electric water heating equipment not connected through a separately metered circuit, the kWh shall be billed as follows:

A. Customer Charge (Per Month) $~~14.00~~15.18

	Summer Season	Winter Season
B. Energy Charge (Per kWh):		
First 1000 kWh per month	$0.~~10751~~11657	$0.08999~~08300~~
Over 1000 kWh per month	$0.11657~~10751~~	$0.08999~~08300~~

2~~BC~~. RESIDENTIAL GENERAL USE AND SPACE HEAT - ONE METER: 2RS6A, 2RW6A

When the customer has electric space heating equipment for the residence and the equipment is of a size and design approved by the Company and not connected through a separately metered circuit, the kWh shall be billed as follows (customer may also have electric water heating equipment, of a size and design approved by the Company, under this option):

A.~~a)~~ Customer Charge (Per Month) $15.18~~14.00~~

	Summer Season	Winter Season
B. Energy Charge (Per kWh)		
First 1000 kWh per month	$0.11657~~10751~~	$0.0810~~407474~~
Over 1000 kWh per month	$0.11657~~10751~~	$0.07074~~06524~~

Issued: May 1, 2018~~June 21, 2017~~
Month Day Year

Effective: ~~June 28, 2017~~
Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

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THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 11

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 11 Sheet 3

Rate Areas No 2 & 4
(Territory to which schedule is applicable)

which was filed ~~June~~September ~~21~~0, 2017~~5~~

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 3 of 4 Sheets

RESIDENTIAL SERVICE
Schedule R (Continued)

~~3~~C~~D~~. RESIDENTIAL GENERAL USE AND SPACE HEAT - 2 METERS: 2RS2A, 2RS3A, 2RW7A

When the customer has electric space heating equipment for the residence and the equipment is of a size and design approved by the Company and connected through a separately metered circuit or may also have electric water heating equipment connected through the same separately metered circuit, the kWh used shall be billed as follows. This option of separately metered space heating is limited to premises connected prior to January 1, 2007.

A. Customer Charge (Per Month)
$15.18~~14.00~~

	Summer Season	Winter Season
B. Energy Charge for Usage on General Use Meter- (Per kWh, Per Month)-		
First 1000 kWh per month	$0.11657~~10751~~	$0.08104~~07474~~
Over 1000 kWh per month	$0.11657~~10751~~	$0.07077~~06527~~
C. Separately metered space heat rate:		
For all kWh (Per kWh)	$0.11657~~10751~~	$0.07074~~06524~~

~~4~~D~~F~~. When a customer has electric space heating equipment and electric water heating equipment of a size and design approved by the Company connected through a separately metered circuit, the kWh used shall be billed on Rate D above. This option of connecting water heating equipment on the separately metered circuit is limited to customers being billed under this rate option prior to March 1, 1999.

MINIMUM:

Minimum Monthly Bill:

Issued: May 1, 2018~~June 21, 2017~~
Month Day Year

Effective: ~~June 28, 2017~~
Month Day Year

~~By:~~ ~~/s/ Darrin R. Ives~~ Vice
Title

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THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 12

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 12 Sheet 1

Rate Areas No 2 & 4
(Territory to which schedule is applicable)

which was filed June~~September~~ 21~~0~~, 2017~~5~~

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 1 of 1 Sheets

RESIDENTIAL OTHER USE
Schedule ROU

AVAILABILITY:

This rate schedule applies to residential customers who do not qualify under any other residential rate. Customers qualifying for this rate will generally be those with well pumps, barns, machine sheds, detached garages, home workshops, or recreational vehicles whose meter is not connected to a single or multiple occupancy dwelling unit. This rate schedule cannot be used for any commercial or industrial customer.

RATE: 2RO1A

	Summer Season	Winter Season
1. Customer Charge (per month)	$15.18~~14.00~~	$15.18~~14.00~~
2. Energy Charge (per kWh)		
All Energy	$0.13609~~12551~~	$0.10693~~09862~~

MINIMUM:

Minimum Monthly Bill:

1.~~(1)~~ Customer Charge; plus

2.~~(2)~~ Any additional charges for line extensions, if applicable; plus

SUMMER AND WINTER SEASONS:

The Summer Season is four consecutive months, beginning and effective May 16 and ending September 15, inclusive. The Winter Season is eight consecutive months, beginning and effective September 16 and ending May 15. Customer bills for meter reading periods including one or more days in both seasons will reflect the number of days in each season.

ADJUSTMENTS AND SURCHARGES:

The rates hereunder are subject to adjustment as provided in the following schedules:

- Energy Cost Adjustment (ECA)
- Energy Efficiency Rider (EER)
- Property Tax Surcharge (PTS)
- Tax Adjustment (TA)
- Transmission Delivery Charge (TDC)

REGULATIONS:

Subject to Rules and Regulations filed with the State Regulatory Commission

Issued: May 1, 2018~~June 21, 2017~~
Month Day Year

Effective: ~~June 28, 2017~~
Month Day Year

By: /s/ Darrin R. Ives Vice President
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THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 15

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 15 Sheet 1

Rate Areas No 2 & 4
(Territory to which schedule is applicable)

which was filed July 21, 2008

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 1 of 2 Sheets

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ENERGY EFFICIENCY RIDER
Schedule EE

APPLICABILITY:

This Energy Efficiency (EE) Rider (Schedule EE) shall be applicable to all non-lighting Kansas Retail Rate Schedules for KCPL. ~~with the exception of Lighting Schedules LS, AL, CL, ML, and TR.~~

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PURPOSE:

This EE Rider ~~is filed in compliance with the Commission's Order in Docket No. 07-KCPE-905-RTS and~~ is designed to recover all costs associated with the following Commission-approved Income-Eligible~~Affordability~~, Energy Efficiency and Demand Response schedules: (1) IEW; (2) PT; (3) BOC; (4) ER; (5) CHP; (6) NH; (7) RHER; (8) RSTP; and (9) DR~~programs (EE Programs),), including internal labor costs, incurred during the time period July 1, 2006 through December 31, 2007 (Program Costs). This EE Rider will be effective as of July 1, 2008 and will recover such Program Costs over the customer usage for the period July 1, 2008 through June 30, 2009. KCPL will file a new EE Rider for Commission approval on or before March 31, 2009 to recover EE Program costs incurred from January 1, 2008 through December 31, 2008 over the time period July 1, 2009 through June 30, 2010. Thereafter,~~ KCPL will file a new EE Rider no later than March 31 of each year to recover EE Program costs incurred during the prior calendar year for recovery over the following July through June period.

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BASIS:

Program Costs will be recovered using an EE factor applied to each customer's bill. The EE factor will be applied to the customer's usage on a kilowatt-hour basis (\$/kWh). Retail customer charges for EE Program Costs are determined by multiplying the kilowatt-hours of electricity billed by the corresponding EE factor. The customer charges associated with this EE Rider will be identified and shown as a separate line on the customer's bill.

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ENERGY EFFICIENCY RIDER AMOUNT CALCULATION:

A separate EE factor will be calculated for each customer class based upon the demand allocator and total kWh for each class. The EE factor (EEF) for each customer class will be calculated to recover the Program Costs for approved EE Programs from the specified period -plus any applicable true up amount from the prior period by applying a class Demand Allocator and then dividing by the total kilowatt-hours (kWh) for that class as follows:

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$$EEF_{(class)} = \frac{(EEC_n + TRUE_{n-1}) \times DA_{(class)}}{KWH_{n\,(class)}}$$

Where:

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EEC_n = All~~The~~ actual costs associated with Commission-approved EE Programs ~~, including internal labor costs,~~ incurred during the applicable time ~~-~~period (n). These costs are recorded in a deferred ~~Account 182441, the~~ regulatory asset account established to accumulate the Kansas jurisdictional costs of all ~~Affordability, Energy Efficiency, and Demand-Side Management~~EE

Issued: May~~July~~ ~~2~~1, 201~~808~~ (Month Day Year)	~~FILED~~	
Effective: (Month Day Year)	~~THE STATE CORPORATION COMMISSION OF KANSAS~~	
By: Darren R. Ives~~Chris Giles~~ Vice President (Title)	~~By:~~	~~Secretary~~

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THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 15

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 15 Sheet 2

Rate Areas No 2 & 4
(Territory to which schedule is applicable)

which was filed March 29~~31~~, 2018~~7~~

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 2 of 2 Sheets

ENERGY EFFICIENCY RIDER
Schedule EE (Continued)
~~(continued)~~

ENERGY EFFICIENCY RIDER AMOUNT CALCULATION: (C~~c~~ontinued)

$TRUE_{n-1}$ = The annual true-up amount for an EE Rider year, to be determined prior to filing the next EE Rider and to be applied to the subsequent EE factor calculation. The true-up amount will reflect any difference between the total EE revenue collected and the actual costs (EEC_n) for the previous applicable time-~~-~~period (n-1). Such true-up amount may be positive or negative. The true-up amount used to calculate the EEF for the first EE Rider equals zero.
~~(n-1). Such true-up amount may be positive or negative. The true-up amount used to calculate the EEF for the first EE Rider equals zero.~~

$DA_{(class)}$ = The demand allocator for the applicable non-lighting classes. This demand allocator shall be based on the 12-CP allocator utilized by the Company for its Class Cost of Service Study in the most recent Kansas retail rate case.

$KWH_{n\ (class)}$ = The actual kWh electric sales for the Kansas jurisdiction for the applicable time-period (n) of the Class Cost of Service Study for the applicable class.

TERM:

This EE Rider shall remain in effect until such time ~~as~~ the Commission-approved amount is recovered. ~~In the event that the Commission rules on Docket No. 08-GIMX-441-GIV, or similar proceeding concerning demand-side management cost recovery, or a law is passed regarding treatment of such expenses, then KCPL shall have the right to file for Commission approval of a compliant recovery methodology to replace or revise this EE Rider.~~ In the event the Commission rules on, or a law is passed regarding treatment of such expenses, then KCPL shall have the right to file for Commission approval of a compliant recovery methodology to replace or revise this EE Rider. KCPL shall have the right to continue recovery under this EE Rider until such time ~~as~~ a replacement methodology is approved and implemented or all Commission-approved amounts are recovered.

NOTES TO THE TARIFF:

1. The references to Accounts within the EE tariff are as defined in the FERC uniform system ~~of~~ accounts.

The EEC factor will be expressed in dollars per kilowatt-hour (kWh) rounded to five decimal places.

2.

EE FACTORS FOR JULY 1, 2018 THROUGH JUNE 30, 2019 USAGE:

Issued: Ma~~rch~~y 1~~29~~, 2018 (Month Day Year)	
Effective: ~~July 1, 2018~~ (Month Day Year)	
By: /s/ Darrin R. Ives Vice-President (Title)	

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THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 16

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 16 Sheet 1

Rate Areas No 2 & 4
(Territory to which schedule is applicable)

which was filed June 21, 2017~~September 10, 2015~~

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 1 of 2 Sheets

RESIDENTIAL TIME OF DAY SERVICE (FROZEN)
Schedule RTOD

AVAILABILITY:

For electric service to a single-occupancy private residence:

Single-phase electric service through one meter for ordinary domestic use for the first 500 new or existing customers who request to be served under this schedule. This limit may be extended upon prior consent of the Company depending upon the availability and installation of metering equipment.

Temporary or seasonal service will not be supplied under this schedule.

This schedule not available after October 1, 2015.

RATE: 2TE1A

Single-phase kWh will be cumulated for billing under this schedule.

1~~A~~. Customer Charge (per customer per month): $21.69~~20.00~~

~~B~~ 2. Energy Charge (per kWh ~~for all kWh per month~~):

Summer Season:	Winter Season:
On-Peak Hours	$0.083547~~7705~~
$0.191067~~7621~~	
Off-Peak Hours	
$0.07991~~370~~	

Issued: May 1, 2018~~June 21, 2017~~
Month Day Year

Effective: ~~June 28, 2017~~
Month Day Year

By: /s/ Darrin R Ives Vice President
Title

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THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 16

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 16 Sheet 2

Rate Areas No 2 & 4
(Territory to which schedule is applicable)

which was filed September~~December~~ 10~~9~~, 2015~~3~~

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 2 of 2 Sheets

RESIDENTIAL TIME OF DAY SERVICE (FROZEN)
Schedule RTOD~~D~~ (Continued)

MINIMUM:

Minimum Monthly Bill:

1. ~~(i)~~ C~~$20.00 per c~~ustomer charge; plus
2. ~~(ii)~~ Any additional charges for line extensions, if applicable.

WINTER SEASON:

Eight consecutive months, spanning the period October 1 of one year to May 31 of the next year.

SUMMER SEASON:

Four consecutive months, spanning the period June 1 to September 30 each year.

SUMMER ON-PEAK AND OFF-PEAK PERIODS:

On-peak hours are defined to be the hours between 1 p.m. and 7 p.m., Monday through Friday, excluding week-day holidays during the Summer Season. Off-Peak hours are defined to be all other hours during the Summer Season. Week-day holidays are Independence Day and Labor Day.

ADJUSTMENTS AND SURCHARGES:

The rates hereunder are subject to adjustment as provided in the following schedules:

- Energy Cost Adjustment (ECA)
- Energy Efficiency Rider (EER)
- Property Tax Surcharge (PTS)
- Tax Adjustment (TA)
- Transmission Delivery Charge (TDC)

REGULATIONS:

Subject to Rules and Regulations filed with the State Regulatory Commission.

Issued: May~~September~~ 1~~0~~, 2018~~15~~
Month Day Year

Effective: ~~October 1, 2015~~
Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

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RESIDENTIAL TIME OF USE PILOT
Schedule RTOU

AVAILABILITY:

Available to single metered Residential customers receiving AMI-metered secondary electric service to a single occupancy private residence or individually metered living units in multiple occupancy residential buildings.

Not available to Customers that own and operate generation connected in parallel with the Company's electric system, or that receive service under Net Metering tariff (Schedule NM). Not available for Temporary, Seasonal, Three phase Standby, Supplemental, Resale or single metered multi-occupancy Residential Service.

APPLICABILITY:

This Pilot shall be available as an option to customers otherwise served under the Company's Residential Service (Schedule R) to encourage customers to shift consumption from higher cost time periods to lower-cost time periods.

This Pilot is limited to a maximum of one thousand (1,000) Residential customers, unless otherwise requested by the Company to be increased and such an increase in participation is approved by the State Regulatory Commission.

Any Customer who has exited the program, has been disconnected for non-payment, or is on a pay agreement may not be allowed to participate in this pilot at the Company's discretion.

Service shall be provided for a fixed term of not less than one (1) year, and for such time thereafter until terminated by either party via (30) day written notice.

Participation in this pilot is contingent upon approval of this rate and adequate recovery of all costs (including marketing, customer education, and administrative costs) and lost margins associated with the pilot rate by the State Regulatory Commission. These rates may be packaged with approved Demand Side Management Pilot Programs where program costs are recovered through the Energy Efficiency Rider (Schedule EE).

RESIDENTIAL TIME OF USE PILOT
Schedule RTOU (Continued)

RATE: RTOU2

1.	Customer Charge (Per month)	$15.18	
		Summer Season	Winter Season
2.	Energy Charge (Per kWh)		
	Peak	$0.28061	$0.20929
	Off-Peak	$0.09354	$0.08202
	Super Off-Peak	$0.04677	$0.03455

PRICING PERIODS:

Pricing periods are established in Central Standard Time year annually, and by season, for weekdays and weekends. The hours of the pricing periods for each season are as follows:

On-Peak:	4pm-8pm
Off-Peak:	6am-4pm; 8pm-12am
Super Off-Peak:	12am-6am

MINIMUM:

Minimum Monthly Bill:

1. Customer Charge; plus
2. Any additional charges for line extensions, if applicable.

SUMMER AND WINTER SEASONS:

The Summer Season is four consecutive months, beginning and effective May 16 and ending September 15, inclusive. The Winter Season is eight consecutive months, beginning and effective September 16 and ending May 15. Customer bills for meter reading periods including one or more days in both seasons will reflect the number of days in each season.

THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 17

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule ______ Sheet ______

Rate Areas No. 2 & 4
(Territory to which schedule is applicable)

which was filed ______

No supplement or separate understanding shall modify the tariff as shown hereon.

RESIDENTIAL TIME OF USE PILOT
Schedule RTOU (Continued)

ADJUSTMENTS AND SURCHARGES:

The rates hereunder are subject to adjustment as provided in the following schedules:

- Energy Cost Adjustment (ECA)
- Energy Efficiency Rider (EER)
- Property Tax Surcharge (PTS)
- Tax Adjustment (TA)
- Transmission Delivery Charge (TDC)

REGULATIONS:

Subject to Rules and Regulations filed with the State Regulatory Commission.

Issued: May 1, 2018
Month Day Year

Effective: ______
Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

RESIDENTIAL DEMAND SERVICE PILOT
Schedule RD

AVAILABILITY:

Available to single-metered Residential customers receiving AMI-metered secondary electric service to a single-occupancy private residence or individually AMI-metered living units in multiple occupancy residential buildings.

Not available to Customers that own and operate generation connected in parallel with the Company's electric system that do not receive service under Net Metering tariff (Schedule NM).

Not available for Temporary, Seasonal, Three phase, Standby, Supplemental, or Resale or single metered multi-occupancy Residential Service.

APPLICABILITY:

This Residential Demand Service Pilot shall be available as an option to customers otherwise served under the Company's Residential Service (Schedule R) to encourage customers to manage their demand.

This Pilot is limited to a maximum of one thousand (1,000) Residential customers, unless otherwise requested by the Company to be increased and such an increase in participation is approved by the State Regulatory Commission.

Any Customer who exits the program, has been disconnected for non-payment, or is on a pay agreement may not be allowed to participate in this pilot at the Company's discretion.

Service shall be provided for a fixed term of not less than one (1) year and for such time thereafter until terminated by either party via thirty (30) day written notice.

Participation in this pilot is contingent upon approval of this rate and adequate recovery of all costs (including marketing, customer education, and administrative costs) and lost margins associated with the pilot rate by the State Regulatory Commission. These rates may be packaged with approved Demand Side Management Pilot Programs where program costs are recovered through the Energy Efficiency Rider (Schedule EE).

THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 18

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule ______ Sheet ______

Rate Areas No. 2 & 4
(Territory to which schedule is applicable)

which was filed ______

No supplement or separate understanding shall modify the tariff as shown hereon.

RESIDENTIAL DEMAND SERVICE PILOT
Schedule RD (Continued)

RATE: 2RD1A

		Summer Season	Winter Season
1.	Customer Charge (Per month)	$15.18	
2.	Demand Charge Per KW of Billing Demand per month	$14.000	$11.500
3.	Energy Charge (Per kWh) All Energy	$0.08126	$0.05982

MINIMUM MONTHLY BILL:

Minimum Monthly Bill:

1. Customer Charge; plus
2. Any additional charges for line extensions, if applicable.

SUMMER AND WINTER SEASONS:

The Summer Season is four consecutive months, beginning and effective May 16 and ending September 15, inclusive. The Winter Season is eight consecutive months, beginning and effective September 16 and ending May 15. Customer bills for meter reading periods including one or more days in both seasons will reflect the number of days in each season.

DETERMINATION OF MONTHLY MAXIMUM DEMAND:

The Monthly Maximum Demand shall be defined as the maximum fifteen (15) minute demand, measured in KW, during the peak period within the billing month. The peak period shall be the daily hours of 4:00 p.m. through 8:00 p.m. Central Time, excluding weekends and the following holidays: (1) New Year's Day; (2) Memorial Day; (3) Independence Day; (4) Labor Day; (5) Thanksgiving Day; and (6) Christmas Day.

Issued: May 1, 2018
Month Day Year

Effective: ______
Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

RESIDENTIAL DEMAND SERVICE PILOT
Schedule RD (Continued)

ADJUSTMENTS AND SURCHARGES:

The rates hereunder are subject to adjustment as provided in the following schedules:

- Energy Cost Adjustment (ECA)
- Energy Efficiency Rider (EER)
- Property Tax Surcharge (PTS)
- Tax Adjustment (TA)
- Transmission Delivery Charge (TDC)

REGULATIONS:

Subject to Rules and Regulations filed with the State Regulatory Commission.

RESIDENTIAL DEMAND SERVICE PLUS TIME OF USE PILOT
Schedule RDTOU

AVAILABILITY:

Available to single-metered Residential customers receiving AMI-metered secondary electric service to a single-occupancy private residence or individually AMI-metered living units in multiple occupancy residential buildings.

Not available to Customers that own and operate generation connected in parallel with the Company's electric system that do not receive service under Net Metering tariff (Schedule NM).

Not available for Temporary, Seasonal, Three phase, Standby, Supplemental, or Resale or single metered multi-occupancy Residential Service.

APPLICABILITY:

This Demand Service Pilot shall be available as an option to customers otherwise served under the Company's Residential Service (Schedule R) to encourage customers to manage their demand and shift their energy.

This Pilot is limited to a maximum of one thousand (1,000) Residential customers, unless otherwise requested by the Company to be increased and such an increase in participation is approved by the State Regulatory Commission.

Any Customer who exits the program, has been disconnected for non-payment, or is on a pay agreement may not be allowed to participate in this pilot at the Company's discretion.

Service shall be provided for a fixed term of not less than one (1) year and for such time thereafter until terminated by either party via thirty (30) day written notice.

Participation in this pilot is contingent upon approval of this rate and adequate recovery of all costs (including marketing, customer education, and administrative costs) and lost margins associated with the pilot rate by the State Regulatory Commission. These rates may be packaged with approved Demand Side Management Pilot Programs where program costs are recovered through the Energy Efficiency Rider (Schedule EE).

RESIDENTIAL DEMAND SERVICE PLUS TIME OF USE PILOT
Schedule RDTOU (Continued)

RATE: RDTO2

		Summer Season	Winter Season
1.	Customer Charge (Per month)	$15.18	
2.	Demand Charge Per KW of Billing Demand per month	$14.000	$11.500
3.	Energy Charge (Per kWh)		
	Peak	$0.19562	$0.14405
	Off-Peak	$0.06521	$0.05363
	Super Off-Peak	$0.03260	$0.02259

PRICING PERIODS:

Pricing periods are established in Central Standard Time year annually, and by season, for weekdays and weekends. The hours of the pricing periods for each season are as follows:

On-Peak:	4pm-8pm
Off-Peak:	6am-4pm; 8pm-12am
Super Off-Peak:	12am-6am

MINIMUM:

Minimum Monthly Bill:

1. Customer Charge; plus
2. Any additional charges for line extensions, if applicable.

SUMMER AND WINTER SEASONS:

The Summer Season is four consecutive months, beginning and effective May 16 and ending September 15, inclusive. The Winter Season is eight consecutive months, beginning and effective September 16 and ending May 15. Customer bills for meter reading periods including one or more days in both seasons will reflect the number of days in each season.

RESIDENTIAL DEMAND SERVICE PLUS TIME OF USE PILOT
Schedule RDTOU (Continued)

DETERMINATION OF MONTHLY MAXIMUM DEMAND:

The Monthly Maximum Demand shall be defined as the maximum fifteen (15) minute demand, measured in KW, during the peak period within the billing month. The peak period shall be the daily hours of 4:00 p.m. through 8:00 p.m. Central Time, excluding weekends and the following holidays: (1) New Year's Day; (2) Memorial Day; (3) Independence Day; (4) Labor Day; (5) Thanksgiving Day; and (6) Christmas Day.

ADJUSTMENTS AND SURCHARGES:

The rates hereunder are subject to adjustment as provided in the following schedules:

- Energy Cost Adjustment (ECA)
- Energy Efficiency Rider (EER)
- Property Tax Surcharge (PTS)
- Tax Adjustment (TA)
- Transmission Delivery Charge (TDC)

REGULATIONS:

Subject to Rules and Regulations filed with the State Regulatory Commission.

THE STATE CORPORATION COMMISSION OF KANSAS

	SCHEDULE 20
KANSAS CITY POWER & LIGHT COMPANY (Name of Issuing Utility)	Replacing Schedule 20 Sheet 1
Rate Areas No 2 & 4 (Territory to which schedule is applicable)	which was filed December 2, 2016
No supplement or separate understanding shall modify the tariff as shown hereon	Sheet 1 of 3 Sheets

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PUBLIC ELECTRIC VEHICLE CHARGING STATION SERVICE
Schedule CCN

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~~**Schedule CCN**~~
PURPOSE:

The Company owns electric vehicle (EV) charging stations throughout its Kansas service territory that are available to the public for purpose of charging an~~to charge their~~ EVs~~s~~ and~~. Such stations~~ may be used by any EV owner~~s~~ who resides either within or outside the Company's Kansas service territory~~ or outside the Company's Kansas service territory~~.

AVAILABILITY:

This rate schedule applies to all energy provided to charge EVs at the Company's public EV charging stations. EV charging service will be available at Company-owned EV charging stations installed at Company and Host locations. The EV charging stations are accessed by using a card provided to users with an established account from the Company's third party vendor.

HOST PARTICIPATION:

EV charging stations are located at Company and Host sites. A Host is an entity within the Company's Kansas service territory that applies for and agrees to locate one or more Company EV charging stations on its premise(s). Host applications will be evaluated for acceptance based on each individual site and application. If a Host's application is approved, the Host~~s~~ must execute an agreement with the Company covering the terms and provisions applicable to the EV charging station(s) upon~~on~~ their premise~~operty if their application is approved~~. No Host~~s~~ shall~~do not~~ receive any compensation for locating an EV charging station~~s~~ upon~~at~~ their premise(s).

The maximum number of EV charging stations identified by the Company for its Kansas service territory under this Schedule CCN is 350. The Company may not exceed 350 EV charging stations under this tariff without approval of the State Regulatory Commission.

PROGRAM ADMINISTRATION:

Charges under this Schedule CCN will be administered and billed through either the Company's third party vendor on behalf of the Company, or directly by the Company depending upon the Billing~~Payment~~ Option chosen by the Host.

BILLING~~PAYMENT~~ OPTIONS:

The charges applicable to an~~y~~ EV charging station session shall~~will~~ include ~~a combination of~~ an Energy Charge for each kilowatt-hour (kWh) provided to charge an EV, ~~plus all applicable riders, surcharges, taxes and fees,~~ and~~plus~~ an optional ~~time based~~ Session Overstay Charge depend~~ent~~ing on the Billing~~payment~~ O~~o~~ption chosen by the Host.

Issued: May 1, 2018~~December 2, 2016~~ (Month Day Year)	
Effective: ~~January 1, 2017~~ (Month Day Year)	
By: /s/ Darrin R. Ives, Vice President (Title)	

THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 20

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 20 Sheet 2

Rate Areas No 2 & 4
(Territory to which schedule is applicable)

which was filed December 2, 2016

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 2 of 3 Sheets

PUBLIC ELECTRIC VEHICLE CHARGING STATION SERVICE
Schedule CCN (Continued)

BILLING OPTIONS: (Continued)

A~~There are two alternative payment options a~~ Host may choose between one of two Billing Options for all EV charging stations located upon their premise(s)~~for EV charging stations~~. The Host's agreement with the Company will identify the chosen Billing O~~payment o~~ption applicable to EV charging stations located on its premise(s). The EV charging station screen, and third party vendor's customer web portal, ~~will~~ identify the applicable Energy and Session Overstay Charges that will be the responsibility of the user at each EV charging station location.

1. Option 1: The Host pays the ~~kilowatt hour (~~kWh~~)~~ Energy Charge plus~~including~~ applicable ~~riders, surcharges,~~ taxes and fees, and, if applicable, the EV charging station user pays the Session Overstay Charge~~, if applicable~~.

2. Option 2: The EV charging station user pays the ~~kilowatt hour (~~kWh~~)~~ Energy Charge plus~~including applicable riders, surcharges,~~ taxes and fees, and, if applicable, the Session Overstay Charge.

RATES FOR SERVICE:

The EV charging station screen and third party vendor's customer web portal will identify both the: (1) per kWh rate as equal to the (Energy Charge plus applicable taxes and fees;~~plicable riders and surcharges)~~ and (2) any Session Overstay Charge rate(s) applicable to that charging station~~, and that will be the responsibility of the EV charging station user for that location.~~

~~1.~~ Energy Charge (per kWh)

1. ~~Per kWh as measured by the EV charging station meter or Company billing meter:~~

Level 2 ~~Charging Station Energy Charge (Per kWh):~~ $0.20000~~1088~~

Level 3 ~~Charging Station Energy Charge (Per kWh):~~ $0.25000~~1180~~

~~2.~~ Session Overstay Charge (Optional) (per hour): $0.00 - $6.00

2. ~~EV Charging Station Session Charge (Per hour): $0.00 - $6.00~~

The Energy Charge shall be defined as a flat rate per kWh, and reflect the inclusion of the: (1) Energy Cost Adjustment (ECA); (2) Energy Efficiency Rider (EER); (3) Property Tax Surcharge (PTS); (4) Transmission Delivery Charge (TDC); and (5) Tax Adjustment (TA). A Session shall be defined as the period of time an EV is connected to the charging station. The Session Overstay Charge is an option that can be implemented at the discretion of the Host and Company to promote improved utilization of the EV charging station(s) located upon their premise.

Issued:	May 1, 2018~~December 2, 2016~~ (Month Day Year)	
Effective:	~~January 1, 2017~~ (Month Day Year)	
By:	/s/ Darrin R Ives	Vice President (Title)

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THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 20

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 20 Sheet 3

Rate Areas No 2 & 4
(Territory to which schedule is applicable)

which was filed December 2, 2016

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 3 of 3 Sheets

PUBLIC ELECTRIC VEHICLE CHARGING STATION SERVICE
Schedule CCN (Continued)

RATES FOR SERVICE: (Continued)

The optional Session Overstay Charge will be configured within the following guidelines as either Charge-Based or Time-Based at the discretion of the Host.

1. Charge-Based – A Charge-Based Session Overstay Charge starts when the EV has stopped charging (but is still connected to the EV charging station) plus a defined grace period granting the user time to end the Charge Session and move the EV.

2. Time-Based – A T~~t~~ime-B~~b~~ased Session Overstay Charge ~~would~~ starts at either the time of initial EV plug-in~~, of the EV~~ or, a predefined time in an active Charge Session (*e.g.*, two hours after initial plug-in) at the Host's discretion and ~~. Also, at the discretion of the Host, the Session Charge rate~~ may increase to a higher rate at a subsequent predefined time in an active Charge Session (*e.g.*, four hours after initial plug-in).

Session Overstay Charges for fractional hours will be prorated. The Session Overstay Charge rate may not exceed $6.00 per hour.

~~**ADJUSTMENTS AND SURCHARGES:**~~

~~The rates hereunder are subject to adjustment as provided in the following schedules:~~

- ~~Energy Cost Adjustment (ECA)~~
- ~~Energy Efficiency Rider (EER)~~
- ~~Property Tax Surcharge (PTS)~~
- ~~Transmission Delivery Charge (TDC)~~
- ~~Tax Adjustment (TA)~~

~~ECA, EER, PTS and TDC adjustments are included in the $/kWh All-In Energy Charge rates. The All-In Energy Charge rates will be adjusted as appropriate for changes in these adjustment mechanisms.~~

~~The rates above do not include tax adjustments pursuant to KCP&L's Schedule TA (also referred to as Schedule 1). Tax adjustments will be added separately to the customer's bill.~~

BILLING:

All users of the Company's public EV charging stations must have an account with the Company's third party vendor. Information on opening an account can be found on the Company's website at ~~http://kcpl.chargepoint.com/~~http://kcpl.chargepoint.com/.

All~~Any~~ charges applicable to any user of an~~the~~ EV charging station ~~user~~ under Billing~~Payment~~ Option 1 or 2 will be billed directly through the Company's third party vendor. All~~Any~~ charges applicable to the Host under Billing~~Payment~~ Option 1 will be billed directly through the Company.

Issued:	May~~December~~ 1~~2~~, 201~~6~~8	
	Month Day Year	
Effective:	~~January 1, 2017~~	
	Month Day Year	
By:	/s/ Darrin R. Ives	Vice President
		Title

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THE STATE CORPORATION COMMISSION OF KANSAS

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)
Rate Areas No 2 & 4
(Territory to which schedule is applicable)

SCHEDULE 21

Replacing Schedule 21 Sheet 1

which was filed November 12, 1998~~August 23, 1991~~

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 1 of ~~1~~4 Sheets

RESIDENTIAL HOME ENERGY REPORT PILOT PROGRAM
Schedule RHER

PURPOSE:

The Residential Home Energy Report Pilot Program will directly support the three residential pilot schedules: (1) RTOU; (2) RD; and (3) RDTOU (Residential Pilots). Therefore, the program is directed to 3,000 residential customers who receive service under one of the three Residential Pilots. This Program is a behavioral energy efficiency and educational program that provides a comparison of the household energy usage information with similar types of customers, or "neighbors". The Home Energy Report shall be delivered in paper, and/or email format, and is composed of several modules of information to help customers understand and manage their energy use. A few examples of modules included are: (1) neighbor/similar home comparison; (2) energy comparisons over time; (3) energy efficiency tips; and (4) utility program promotional material. The Home Energy Report provides information designed to influence customers' behavior to lower energy usage.

AVAILABILITY:

Participation in this Program is limited to participants in the Residential Pilots only. This Program will operate as an opt-out only program, meaning the Company will select customers for participation in the program and will allow opt-out if desired.

PROGRAM FUNDING:

The total Program budget will be allocated between the following budget categories: (1) program delivery; (2) administration; and (3) evaluation (labor and loadings excluded from administration budget). This Program and its costs shall be eligible for recovery under the Company's Energy Efficiency Rider, Schedule EE, subject to the provisions thereof.

EVALUATION:

The Company will hire a third-party evaluator to perform an Evaluation, Measurement, and Verification (EM&V) on the Home Energy Report Pilot Program.

~~RURAL RESIDENTIAL SERVICE~~
~~Schedule F~~

~~CANCELLED~~

Issued: May 1, 2018~~November 12, 1998~~ (Month Day Year)	~~FILED~~
Effective: ~~For Bills Rendered on or After March 1, 1999~~ (Month Day Year)	~~THE STATE CORPORATION COMMISSION OF KANSAS~~
By: /s/ Darrin R. Ives~~J. S.~~ ~~Senior~~ Vice (Title)	~~By:~~ ~~Secretary~~

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THE STATE CORPORATION COMMISSION OF KANSAS

KANSAS CITY POWER & LIGHT COMPANY (Name of Issuing Utility)	SCHEDULE 22
Rate Areas No 2 & 4 (Territory to which schedule is applicable)	Replacing Schedule 22 Sheet 1
	which was filed November 12, 1998~~June 20, 1989~~
No supplement or separate understanding shall modify the tariff as shown hereon	Sheet 1 of 1~~2~~ Sheets

RESIDENTIAL SMART THERMOSTAT PILOT PROGRAM
Schedule RSTP

PURPOSE:

The Residential Smart Thermostat Pilot Program will directly support the three residential pilot schedules: (1) RTOU; (2) RD; and (3) RDTOU (Residential Pilots). Therefore, the program is directed to 3,000 residential customers who receive service under one of the three Residential Pilots. Customers participating in one of the three Residential Pilots may receive a smart thermostat. This Program is intended to support residential customers in their transition to a Residential Pilot by providing them with a smart thermostat.

The smart thermostats have several features and capabilities that can help customers decrease their energy use, which include: (1) scheduled programming/learning capability; (2) recommended eco-temperatures; and (3) auto-away settings. The Company may leverage other technologies, and programs, to advance the smart thermostat software in an effort to maximize support to customers on a Residential Pilot by managing their energy use to meet Company objectives for load shaping.

AVAILABILITY:

Customers must maintain a secure home Wi-Fi enabled internet service and have a working central air conditioning system or heat pump. Residential property owner's (owner occupant or landlord for a rental property) permission is required to receive a smart thermostat at an incentive level determined by the Company. Customers must agree to install the smart thermostat at their premise receiving service under one of the Residential Pilots within fourteen (14) days of receiving the device, and keep it installed, operational, and connected to a secure home Wi-Fi network for the duration of the program. Customers must agree to not sell the device for the duration of the program. If it is found that they do, a debit will be issued on their utility bill for the Manufacture Suggested Retail Price (MSRP) of the smart thermostat or the value of incentive provided to the customer. Payment of that debit will be the customer's responsibility.

PROGRAM FUNDING:

The total Program budget will be allocated between the following budget categories: (1) program delivery; (2) marketing; (3) administration; and (4) evaluation (labor and loadings excluded from administration budget). This Program and its costs shall be eligible for recovery under the Company's Energy Efficiency Rider, Schedule EE, subject to the provisions thereof.

EVALUATION:

The Company will hire a third-party evaluator to perform an Evaluation, Measurement, and Verification (EM&V) on this Program.~~**RURAL RESIDENTIAL SERVICE**~~
~~**(All Electric Home)**~~
~~**Schedule FF**~~

~~CANCELLED~~

Issued: May 1, 2018~~November 12, 1998~~ (Month Day Year)	~~FILED~~
Effective: ~~For Bills Rendered on or After March 1, 1999~~ (Month Day Year)	~~THE STATE CORPORATION COMMISSION OF KANSAS~~
By: /s/ Darrin R. Ives~~J. S.~~ ~~Senior~~ Vice (Title)	~~By:~~ ~~Secretary~~

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DEMAND SERVICE FOR RESIDENTIAL DISTRIBUTED GENERATION
Schedule RDG

AVAILABILITY:

Any Customer-Generator operating or adding generation powered by Renewable Energy Resources or taking service under an interconnection agreement connecting to KCP&L's distribution system after XXX XX, XXX (effective date of rates in this case) must take service under this rate schedule.

For electric service to a single-occupancy private residence. Single-phase electric service through one meters for ordinary domestic use for all customers who request to be served under this rate. The Company reserves the right in all instances to designate whether a Customer-Generator is or is not a residential customer.

Three-phase electric service for the operation of cooling and air conditioning equipment for domestic use. For three-phase, built-up central plant air conditioning systems of at least 25 tons single-unit cooling capacity, service is available under this schedule only if permitted by the Company, with the Company exercising sole discretion in the case of each Customer-Generator. The availability of three-phase Residential Service for such air conditioning systems also shall be contingent upon the Customer-Generator paying the full cost of the required three-phase line extension prior to construction of the extension.

Single-phase electric service through a single or separately metered circuit for space heating purposes in the residence. Single metered electric space heating equipment shall be of a size and design sufficient to heat the entire residence. Electric space heating equipment may be supplemented by wood burning fireplaces, wood burning stoves, active or passive solar heating, and used in conjunction with fossil fuels where the combination of energy sources results in a net economic benefit to the Customer-Generator. Electric space heating equipment shall be permanently installed and thermostatically controlled.

Customers currently served under two meter heat rates shall be required to convert their metering from two meters to a single meter or agree to provisions to combine the readings from the two meters when billed under this schedule.

Not available for Temporary, Seasonal, Standby, or Resale Service.

TERM OF CONTRACT:

Contracts under this schedule shall be for a period of not less than one year from the effective date thereof.

DEMAND SERVICE FOR RESIDENTIAL DISTRIBUTED GENERATION
Schedule RDG (Continued)

DEFINITIONS:

1. Customer-Generator: The owner and operator of a facility which:

   A. Is powered by a Renewable Energy Resource;
   B. Is located on a premise owned, operated, leased, or otherwise controlled by the Customer-Generator;
   C. Is interconnected and operates in parallel phase and synchronization with the Company facilities and is in compliance with the Company standards;
   D. Is intended primarily to offset part or all of the Customer-Generator's own electrical energy requirements; and
   E. Contains a mechanism, approved by the Company that automatically disables the unit and interrupts the flow of electricity back onto the Company's electric lines in the event that service to the Customer-Generator is interrupted.

2. Renewable Energy Resources: Net renewable generation capacity produced from wind, solar thermal sources, photovoltaic cells and panels, dedicated crops grown for energy production, cellulosic agricultural residues, plant residues, methane from landfills or from wastewater treatment, clean and untreated wood products such as pallets, hydroelectric sources (existing hydropower, new hydropower, not including pumped storage, that has a name plate rating of 10 megawatts or less), fuel cells using hydrogen produced by one of the above-named renewable energy sources; and other sources of energy, not including nuclear power, that become available, and that are certified as renewable by the rules and regulations of the Kansas Corporation Commission.

RATE: 2RSDG

Single-phase and Three-phase service will be cumulated for billing under this schedule.

		Summer Season	Winter Season
1.	Customer Charge (Per month)	$14.00	
2.	Demand Charge Per KW of Billing Demand per month	$9.000	$2.000
3.	Energy Charge (Per kWh) All Energy	$0.08683	$0.06704

Issued: May 1, 2018
Month Day Year

Effective: ______
Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

DEMAND SERVICE FOR RESIDENTIAL DISTRIBUTED GENERATION
Schedule RDG (Continued)

MINIMUM MONTHLY BILL:

Minimum Monthly Bill:

1. Customer Charge; plus
2. Any additional charges for line extensions, if applicable.

SUMMER AND WINTER SEASONS:

The Summer Season is four consecutive months, beginning and effective May 16 and ending September 15, inclusive. The Winter Season is eight consecutive months, beginning and effective September 16 and ending May 15. Customer bills for meter reading periods including one or more days in both seasons will reflect the number of days in each season.

DETERMINATION OF MONTHLY BILLING DEMAND:

The Monthly Billing Demand shall be defined as the maximum fifteen (15) minute demand, measured in KW, during the peak period within the billing month. The peak period shall be the daily hours of 4:00 p.m. through 8:00 p.m. Central Time, excluding weekends, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

ADJUSTMENTS AND SURCHARGES:

The rates hereunder are subject to adjustment as provided in the following schedules:

- Energy Cost Adjustment (ECA)
- Energy Efficiency Rider (EER)
- Property Tax Surcharge (PTS)
- Tax Adjustment (TA)
- Transmission Delivery Charge (TDC)

REGULATIONS:

Subject to Rules and Regulations filed with the State Regulatory Commission.

THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 31

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 31 Sheet 2

Rate Areas No 2 & 4
(Territory to which schedule is applicable)

which was filed June 21, 2017~~September 10, 2015~~

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 2 of 6 Sheets

SMALL GENERAL SERVICE
Schedule SGS
(Continued)

RATE FOR SERVICE AT SECONDARY VOLTAGE: 2SGHE, 2SGHH, 2SGSE, 2SGSH, 2SUSE, 2SUSH,

~~A.~~1. CUSTOMER CHARGE:

A. ~~(i)~~ For Metered Service:

~~(a)~~ Customer pays one of the following charges per month based upon the Facilities Demand:

a.)

0-24 kW $21.70~~18.36~~

25 kW or above

~~(b.)~~ plus, additional meter charge for Customers with separately metered space heat: $2.57~~2.17~~

B. ~~(ii)~~ For Unmetered Service Customer pays: $9.32~~7.88~~

~~B.~~ 2. FACILITIES CHARGE:

Per kW of Facilities Demand per month

First 25 kW

All kW over 25 kW $3.343~~2.828~~

3~~C~~. ENERGY CHARGE:

Per kWh associated with:	Summer Season	Winter Season
First 180 Hours Use per month	$0.14429~~14429~~ per kWh	$0.11484~~11484~~ per kWh
Next 180 Hours Use per month	$0.06337~~06337~~ per kWh	$0.05413~~05413~~ per kWh
Over 360 Hours Use per month	$0.05662~~05662~~ per kWh	$0.04268~~04268~~ per kWh

~~D.~~4. SEPARATELY METERED SPACE HEAT: 2SGHE, 2SGHH

When the customer has separately metered electric space heating equipment of a size and design approved by the Company, the kWh used for electric space heating shall be billed as follows:

~~A.(i) Applicable during the Winter Season:~~

Issued:	May 1, 2018~~June 21, 2017~~ (Month Day Year)	
Effective:	~~June 28, 2017~~ (Month Day Year)	
By:	/s/ Darrin R. Ives	Vice President (Title)

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THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 31

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 31 Sheet 3

Rate Areas No 2 & 4
(Territory to which schedule is applicable)

which was filed June 21, 2017~~September 10, 2015~~

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 3 of 6 Sheets

SMALL GENERAL SERVICE
Schedule SGS (Continued)

RATE FOR SERVICE AT PRIMARY VOLTAGE: 2SGSF, 2SGSG

1. CUSTOMER CHARGE:

A. For Metered Service:
Customer pays one of the following charges per month based upon the Facilities Demand:

0-24 kW	$21.70~~18.36~~
25 kW or above	$56.73~~47.99~~

~~4.~~ 2. FACILITIES CHARGE:

Per kW of Facilities Demand per month

First 26 kW	$0.00
All kW over 26 kW	$2.829~~2.393~~

3~~C~~. ENERGY CHARGE:

Per kWh associated with:	Summer Season	Winter Season
First 180 Hours Use per month	$0.14067~~14067~~ per kWh	$0.11191~~11191~~ per kWh
Next 180 Hours Use per month	$0.06162 per kWh	$0.05279~~05279~~ per kWh
Over 360 Hours Use per month	$0.05514 per kWh	$0.04150~~04150~~ per kWh

Issued: May 1, 2018~~June 21, 2017~~
Month Day Year

Effective: ~~June 28, 2017~~
Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

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SMALL GENERAL SERVICE
Schedule SGS (Continued)

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REACTIVE DEMAND ADJUSTMENT (Secondary and Primary Service):

Company may determine the customer's monthly maximum 30-minute reactive demand in kilovars. In each month a charge of $0.~~665~~786 per month shall be made for each kilovar by which such maximum reactive demand is greater than fifty percent (50%) of the customer's Monthly Maximum Demand (kW) in that month. The maximum reactive demand in kilovars shall be computed similarly to the Monthly Maximum Demand as defined in the Determination of Demands section.

MINIMUM MONTHLY BILL:

The Minimum Monthly Bill shall be equal to the sum of the Customer Charge, Facili ies Charge, and Reactive Demand Adjustment.

UNMETERED SERVICE:

Unmetered secondary service refers to electric service which is not measured by a kWh meter or by a kWh/demand meter. This type of service usually applies to delivery points for which it is impractical or difficult to install and read meters. The usage and demand are calculated by using typical hours of use and rated equipment loads.

SUMMER AND WINTER SEASONS:

The Summer Season is four consecutive months, beginning and effective May 16 and ending September 15, inclusive. The Winter Season is eight consecutive months, beginning and effective September 16 and ending May 15. Customer bills for meter reading periods including one or more days in both seasons will reflect the number of days in each season.

CUSTOMER DEFINITIONS:

1. Secondary Voltage Customer - Receives service on the low side of the line transformer.
2. Primary Voltage Customer - Receives service at Primary voltage of 12,000 volts or over but not exceeding 69,000 volts. Customer will own all equipment necessary for transformation including the line transformer.
3. Water Heating Customer - Customer connected prior to March 1, 1999, that receives service through a separately metered circuit as the sole means of water heating with an electric water heater of a size and design approved by the Company.

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THE STATE CORPORATION COMMISSION OF KANSAS

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)
Rate Areas No 2 & 4
(Territory to which schedule is applicable)

SCHEDULE 32

Replacing Schedule 32 Sheet 2

which was filed June 21, 2017~~September 10, 2015~~

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 2 of 6 Sheets

MEDIUM GENERAL SERVICE
Schedule MGS (Continued)

RATE FOR SERVICE AT SECONDARY VOLTAGE: 2MGHE, 2MGHH, 2MGSE, 2MGSH

~~A.~~1. CUSTOMER CHARGE:

A. ~~(i)~~ Customer pays the following charge per month: $54.69~~49.57~~

B. ~~(ii)~~ plus, additional meter charge for customers with separately metered space heat: $2.56~~2.32~~

2~~B~~. FACILITIES CHARGE:

Per kW of Facilities Demand per month $3.192~~2.893~~

3 ~~C.~~ DEMAND CHARGE: Summer Season Winter Season
~~Summer Season Winter Season~~

Per kW of Billing Demand per month $~~4.048~~4.466 $2.263~~2.051~~

4 ~~D.~~ ENERGY CHARGE:

Per kWh associated with: Summer Season Winter Season
~~Summer Season Winter Season~~

First 180 Hours Use per month $0.09178~~09178~~ per kWh $0.08218~~08218~~ per kWh

Next 180 Hours Use per month $0.05754~~05754~~ per kWh $0.04613~~04613~~ per kWh

Over 360 Hours Use per month $0.05822~~05822~~ per kWh $0.03882~~03882~~ per kWh

~~E.~~5. SEPARATELY METERED SPACE HEAT: 2MGHE, 2MGHH

When the customer has separately metered electric space heating equipment of a size and design approved by the Company, the kWh used for electric space heating shall be billed as follows:

A.~~(i)~~ Applicable during the Winter Season:
$0.02814~~02551~~ per kWh per month.

B.~~(ii)~~ Applicable during the Summer Season:
The demand established and energy used by equipment connected to the space heating

Issued: May 1, 2018~~June 21, 2017~~
Month Day Year

Effective: ~~June 28, 2017~~
Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

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THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 32

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 32 Sheet 3

Rate Areas No 2 & 4
(Territory to which schedule is applicable)

which was filed ~~June~~September ~~21~~0, 201~~7~~5

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 3 of 6 Sheets

MEDIUM GENERAL SERVICE
Schedule MGS
(Continued)

RATE FOR SERVICE AT PRIMARY VOLTAGE: 2MGSF, 2MGSG

~~A.~~ 1. CUSTOMER CHARGE:

Customer pays the following charge per month: $54.69~~49.57~~

~~B.~~ 2. FACILITIES CHARGE:

Per kW of Facilities Demand per month $2.7022.449

~~C.~~ 3. DEMAND CHARGE: Summer Season Winter Season ~~Summer Season~~ ~~Winter Season~~

Per kW of Billing Demand per month $4.3703.961 $2.2192.011

~~D.~~ 4. ENERGY CHARGE:

Per kWh associated with:	Summer Season	Winter Season
First 180 Hours Use per month	$0.0894~~08949~~ per kWh	$0.0803~~108031~~ per kWh
Next 180 Hours Use per month	$0.0557~~405574~~ per kWh	$0.0450~~504505~~ per kWh
Over 360 Hours Use per month	$0.0532~~705327~~ per kWh	$0.0354~~703547~~ per kWh

Issued: May 1, 2018~~June 21, 2017~~
Month Day Year

Effective: ~~June 28, 2017~~
Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

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MEDIUM GENERAL SERVICE
Schedule MGS **(Continued)**

REACTIVE DEMAND ADJUSTMENT (Secondary and Primary Service):

Company may determine the customer's monthly maximum 30-minute reactive demand in kilovars. In each month a charge of $0.~~670~~739 per month shall be made for each kilovar by which such maximum reactive demand is greater than fifty percent (50%) of the customer's Monthly Maximum Demand (kW) in that month. The maximum reactive demand in kilovars shall be computed similarly to the Monthly Maximum Demand as defined in the Determination of Demands section.

MINIMUM MONTHLY BILL:

The Minimum Monthly Bill shall be equal to the sum of the Customer Charge, Facilities Charge, Demand Charge, and Reactive Demand Adjustment.

SUMMER AND WINTER SEASONS:

The Summer Season is four consecutive months, beginning and effective May 16 and ending September 15, inclusive. The Winter Season is eight consecutive months, beginning and effective September 16 and ending May 15. Customer bills for meter reading periods including one or more days in both seasons will reflect the number of days in each season.

CUSTOMER DEFINITIONS:

1. Secondary Voltage Customer - Receives service on the low side of the line transformer.

2. Primary Voltage Customer - Receives service at Primary voltage of 12,000 volts or over but not exceeding 69,000 volts. Customer will own all equipment necessary for transformation including the line transformer.

3. Water Heating Customer - Customer connected prior to March 1, 1999, that receives service through a separately metered circuit as the sole means of water heating with an electric water heater of a size and design approved by the Company.

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THE STATE CORPORATION COMMISSION OF KANSAS

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)
Rate Areas No 2 & 4
(Territory to which schedule is applicable)

SCHEDULE 33

Replacing Schedule 33 Sheet 2

which was filed ~~September~~ June 2~~1~~10, 201~~5~~7

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 2 of 8 Sheets

LARGE GENERAL SERVICE
Schedule LGS (Continued)

RATE FOR SERVICE AT SECONDARY VOLTAGE: 2LGHE, 2LGHH, 2LGSE, 2LGSH

1. CUSTOMER CHARGE:

~~(i)~~ Customer pays one of the following charges per month based upon the Facilities Demand:

A. 0 - 999 kW $114.38~~104.62~~
1000 kW or above $782.28~~715.54~~

B. ~~(ii)~~ plus, additional meter charge for customers with separately metered space heat: $2.53~~2.31~~

~~B.~~ 2. FACILITIES CHARGE:

Per kW of Facilities Demand per month $3.313~~3.030~~

~~C.~~ 3. DEMAND CHARGE:

	Summer Season	Winter Season
Per kW of Billing Demand per month	$7.14~~6.536~~	$3.627 ~~$3.318~~

~~D.~~ 4. ENERGY CHARGE:

Per kWh associated with:	Summer Season	~~Summer Season~~
First 180 Hours Use per month	$0.06879~~06879~~ per kWh	$0.06895~~06895~~ per kWh
Next 180 Hours Use per month	$0.04916~~04916~~ per kWh	$0.04189~~04189~~ per kWh
Over 360 Hours Use per month	$0.02811~~02811~~ per kWh	$0.03130~~03130~~ per kWh

~~E.~~ 5. SEPARATELY METERED SPACE HEAT: 2LGHE, 2LGHH

When the customer has separately metered electric space heating equipment of a size and design approved by the Company, the kWh used for electric space heating shall be billed as follows:

A. ~~(i)~~ Applicable during the Winter Season:
$0.02695~~02465~~ per kWh per month.

Issued: May 1, 2018~~June 21, 2017~~
Month Day Year

Effective: ~~June 28, 2017~~
Month Day Year

By: /s/ Darrin R Ives Vice President
Title

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LARGE GENERAL SERVICE
Schedule LGS (Continued)

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RATE FOR SERVICE AT PRIMARY VOLTAGE: 2LGSF, 2LGSG

~~A~~ 1. CUSTOMER CHARGE:

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Customer pays one of the following charges per month based upon the Facilities Demand:

0 - 999 kW	$114.38~~104.62~~
1000 kW or above	$782.28~~715.54~~

2~~B~~. FACILITIES CHARGE:

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Per kW of Facilities Demand per month $2.781~~2.544~~

3~~C~~. DEMAND CHARGE: Summer Season Winter Season

~~Summer Season Winter Season~~

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Per kW of Billing Demand per month $7.012~~6.414~~ $3.548~~3.245~~

4~~D~~. ENERGY CHARGE:

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Per kWh associated with:	Summer Season	Winter Season
First 180 Hours Use per month	$0.06682~~06682~~ per kWh	$0.06681~~06681~~ per kWh
Next 180 Hours Use per month	$0.04769~~04769~~ per kWh	$0.04092~~04092~~ per kWh
Over 360 Hours Use per month	$0.02705~~02705~~ per kWh	$0.03052~~03052~~ per kWh

THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 33

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 33 Sheet 4

Rate Areas No 2 & 4
(Territory to which schedule is applicable)

which was filed June 21, 2017~~September 10, 2015~~

No supplement or separate understanding shall modify the tariff as shown hereon

LARGE GENERAL SERVICE
Schedule LGS (Continued)

RATE FOR SERVICE AT SUBSTATION VOLTAGE: 2LGSU, 2LGSV

~~A.~~ CUSTOMER CHARGE:

1. Customer pays the following charge per month: $835.11~~763.86~~

~~B.~~ FACILITIES CHARGE:

2. Per kW of Facilities Demand per month $0.882~~807~~

~~C.~~ DEMAND CHARGE:

3. Per kW of Billing Demand per month

	Summer Season	Winter Season
First 2520 kW	$12.150~~11.113~~	$8.258~~7.553~~
Next 2520 kW	$11.347~~10.379~~	$7.528~~6.886~~
Next 2520 kW	$8.357~~7.644~~	$5.835~~5.337~~
All kW over 7560 kW	$6.099~~5.579~~	$4.490~~4.107~~

~~D.~~ ENERGY CHARGE:

4. Per kWh associated with:

~~Summer Season Winter Season~~

	Summer Season	Winter Season
First 180 Hours Use per month	$0.0571	$0.05347~~05347~~ per kWh
Next 180 Hours Use per month	$0.03465~~03465~~ per kWh	$0.03776~~03776~~ per kWh
Over 360 Hours Use per month	$0.02005	$0.02728~~02728~~ per kWh

Issued: May 1, 2018~~June 21, 2017~~
Month Day Year

Effective: ~~June 28, 2017~~
Month Day Year

By: /s/ Darrin R Ives Vice President
Title

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THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 33

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 33 Sheet 5

Rate Areas No 2 & 4
(Territory to which schedule is applicable)

which was filed June 21, 2017~~September 10, 2015~~

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 5 of 8 Sheets

LARGE GENERAL SERVICE
Schedule LGS (Continued)

RATE FOR SERVICE AT TRANSMISSION VOLTAGE: 2LGSW, 2LGSZ

1. CUSTOMER CHARGE:
Customer pays the following charge per month: $835.11

2. FACILITIES CHARGE:
Per kW of Facilities Demand per month $0.000

3. DEMAND CHARGE:

Per kW of Billing Demand per month	Summer Season	Winter Season
First 2541 kW	$12.040	$8.184
Next 2541 kW	$11.247	$7.462
Next 2541 kW	$8.309	$5.802
All kW over 7623 kW	$6.066	$4.465

4. ENERGY CHARGE:

Per kWh associated with:	Summer Season	Winter Season
First 180 Hours Use per month	$0.05645 per kWh	$0.05291 per kWh
Next 180 Hours Use per month	$0.03422 per kWh	$0.03733 per kWh
Over 360 Hours Use per month	$0.01961 per kWh	$0.02683 per kWh

~~1. CUSTOMER CHARGE:~~

~~Customer pays the following charge per month: $763.86~~

~~1. FACILITIES CHARGE:~~

~~Per kW of Facilities Demand per month $0.00~~

~~C. DEMAND CHARGE:~~

~~Per kW of Billing Demand per month~~	~~Summer Season~~	~~Winter Season~~
~~First 2541 kW~~	~~$ 11.013~~	~~$7.486~~
~~Next 2541 kW~~	~~$10.287~~	~~$6.825~~
~~Next 2541 kW~~	~~$7.600~~	~~$5.307~~
~~All kW over 7623 kW~~	~~$ 5.548~~	~~$4.084~~

~~D. ENERGY CHARGE:~~

~~Per kWh associated with: Summer Season Winter Season~~

~~First 180 Hours Use per month $0.05645 per kWh~~

Issued: May 1, 2018~~June 21, 2017~~
Month Day Year

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Month Day Year

By: /s/ Darrin R Ives Vice President
Title

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THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 34

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 34 Sheet 1

Rate Areas No 2 & 4
(Territory to which schedule is applicable)

which was filed December 13, 2012~~8, 2006~~

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 1 of 2~~8~~ Sheets

LARGE GENERAL SERVICE OFF-PEAK RIDER

Schedule LGS-2

PROVISIONS:

During Off-Peak hours, subject to the conditions hereinafter stated, the Customer may exceed his On-Peak Demand and not be billed for such excess demand.

DEFINITIONS:

1. Off-Peak hours shall be the hours between 7:00 p.m. and 11:00 a.m. of the following day, and~~-~~ all hours between 7:00 p.m. Friday and 11:00 a.m. of the following Monday. All hours shall be considered Off-Peak for the following holidays: (1) New Year's Day; (2) Memorial Day; (3) Independence Day; (4) Labor Day; (5) Thanksgiving Day; and (6) Christmas Day.

2. On-Peak hours are all hours other than Off-Peak hours.

3. On-Peak Demand is the highest 30-minute demand established by the Customer during On-Peak hours.

4. Off-Peak Demand is the highest 30-minute demand established by the Customer during Off-Peak hours.

CONDITIONS:

1. The Customer's premise(s) must be serviced and billed using a Company meter capable of measuring demand.

2. The Customer must make a written request and the Company shall, in its sole judgment, determine whether sufficient reason exists for the application of this provision. The Company shall notify the Customer in writing of its determination to accept or reject the Customer's request.

3. The Customer's Off-Peak Demand may exceed the Customer's On-Peak Demand during such Off-Peak Hours to the extent which the Company shall, in its sole judgment, determine that its generating and delivery facilities have sufficient capacity to permit supplying such excess demand without disturbing service to its other Customers. The Company may supply the Customer, in writing, a schedule of such excess demands which may be imposed during Off-Peak Hours. The Company may, upon thirty (30) day's written notice, change such schedule.

4. Nothing in this provision shall be construed as requiring the Company to provide additional generating or delivery facilities for such excess demand.

Issued: May 1, 2018~~December 13, 2012~~ (Month Day Year)	~~FILED~~
Effective: ~~January 1, 2013~~ (Month Day Year)	~~THE STATE CORPORATION COMMISSION OF KANSAS~~
By: /s/ Darrin R. Ives Vice (Title)	~~By:~~

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THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 34

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 34 Sheet 2

Rate Areas No 2 & 4
(Territory to which schedule is applicable)

which was filed December 13~~8~~, 2012~~06~~

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 2 of 2~~8~~ Sheets

LARGE GENERAL SERVICE OFF-PEAK RIDER
Schedule LGS-2 (Continued)

CONDITIONS: (Continued)

5. If the Customer's Off-Peak Demand is within the limits outlined in Condition 3 hereof, the Customer's Monthly Maximum Demand shall be based on the Customer's On-Peak Demand.

6. The Company, during Off-Peak Hours, in the event of an emergency which would affect deliveries to its other Customers, may require the curtailment of all or part of such Off-Peak Demand which is in excess of the On-Peak Demand.

7. That portion of any demand established in a month during the Off-Peak Hours which is above the Off-Peak Demand allowed by the Company shall be added to the highest demand established during On-Peak Hours in such month for the purpose of determining the Monthly Maximum Demand.

8. In the event that service under this provision is made available to more than one Customer, the available generating and delivery capacity may be prorated on the basis of the prior month's On-Peak Demands if sufficient capacity is not available to supply the total amount requested.

9. Depending upon energy supply and cost conditions, the Company may temporarily extend the Off-Peak Hours. The Extended Off-Peak Hours will only be available to Customers whose Off-Peak Demands during normal Off-Peak Hours regularly exceed their On-Peak Demands, and who make written request to the Company for Extended Off-Peak Hours. The Company, in its sole judgment, may alter, or cancel, all, or a portion, of Extended Off-Peak Hours upon telephone or fax notice to the Customer. Upon notification of cancellation of Extended Off-Peak Hours the Customer shall adjust demand, at the time the cancellation is to take effect or within sixty (60) minutes if the cancellation is effective immediately, to not exceed the level of the Customer's then current On-Peak Demand. If a Customer fails to maintain a demand at or below the then current On-Peak Demand during any portion of the cancelled Extended Off-Peak Hours, then 30-minute Demands established after the effective time of the cancellation or after the sixty (60) minute grace period, if applicable, shall be considered in the determination of the On-Peak Demand, and that Customer may be ineligible for Extended Off-Peak Hours for a period of twelve (12) months.

~~LARGE POWER SERVICE~~
~~Schedule LPS~~

~~CANCELLED~~

Issued: May 1, 2018~~December 13, 2012~~ (Month Day Year)	~~FILED~~
Effective: ~~January 1, 2013~~ (Month Day Year)	~~THE STATE CORPORATION COMMISSION OF KANSAS~~
By: /s/ Darrin R. Ives, Vice (Title)	~~By:~~

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THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 44

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 44 Sheet 2

Rate Areas No 2 & 4
(Territory to which schedule is applicable)

which was filed June~~September~~ 21~~0~~, 2017~~5~~

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 2 of 5 Sheets

SMALL GENERAL SERVICE – SPACE HEATING
Schedule SGA
(Continued)

RATE FOR SERVICE AT SECONDARY VOLTAGE: 2SGAE, 2SGAH

~~1.~~ CUSTOMER CHARGE:

1. Customer pays one of the following charges per month based upon the Facilities Demand:

0 - 24 kW	$21.70~~18.36~~
25 kW or above	$56.73~~47.99~~

~~B.~~ FACILITIES CHARGE:

2. Per kW of Facilities Demand per month

First 25 kW	$0.000
All kW over 25 kW	$3.343~~2.8280~~

3.~~C.~~ ENERGY CHARGE:

Per kWh associated with:

	Summer Season	Winter Season
First 180 Hours Use per month	$0.14429~~14429~~ per kWh	$0.07809~~07809~~ per kWh
Next 180 Hours Use per month	$0.06337~~06337~~ per kWh	$0.04739~~04739~~ per kWh
Over 360 Hours Use per month	$0.05662~~05662~~ per kWh	$0.04140~~04140~~ per kWh

Issued: May 1, 2018~~June 21, 2017~~
Month Day Year

Effective: ~~June 28, 2017~~
Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

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THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 44

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 44 Sheet 3

Rate Areas No 2 & 4
(Territory to which schedule is applicable)

which was filed June 21, 2017~~September 10, 2015~~

No supplement or separate understanding
shall modify the tariff as shown hereon

Sheet 3 of 5 Sheets

SMALL GENERAL SERVICE – SPACE HEATING
Schedule SGA
(Continued)

RATE FOR SERVICE AT PRIMARY VOLTAGE: 2SGAF, 2SGAG

~~A.~~ 1. CUSTOMER CHARGE:

Customer pays one of the following charges per month based upon the Facilities Demand:

0 - 24 kW	$21.70~~18.36~~
25 ~~25~~ kW or above	$56.73~~47.99~~

~~A.~~ 2. FACILITIES CHARGE

Per kW of Facilities Demand per month

First 26 kW	$0.00
All kW over 26 kW	$2.829~~2.393~~

~~C.~~ 3. ENERGY CHARGE:

Per kWh associated with:

	Summer Season	Winter Season
First 180 Hours Use per month	$0.14067~~14067~~ per kWh	$0.07621~~07621~~ per kWh
Next 180 Hours Use per month	$0.06162 per kWh	$0.04617~~04617~~ per kWh
Over 360 Hours Use per month	$0.05514 per kWh	$0.04011~~04011~~ per kWh

Issued:	May 1, 2018~~June 21, 2017~~ (Month Day Year)
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By:	/s/ Darrin R. Ives, Vice President (Title)

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THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 44

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 44 Sheet 4

Rate Areas No 2 & 4
(Territory to which schedule is applicable)

which was filed ~~September~~ June ~~10~~ 21, ~~2015~~ 2017

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 4 of 5 Sheets

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SMALL GENERAL SERVICE – SPACE HEATING
Schedule SGA
(Continued)

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REACTIVE DEMAND ADJUSTMENT (Secondary and Primary Service):

Company may determine the customer's monthly maximum 30-minute reactive demand in kilovars. In each month a charge of $0.~~665~~786 per month shall be made for each kilovar by which such maximum reactive demand is greater than fifty percent (50%) of the customer's Monthly Maximum Demand (kW) in that month. The maximum reactive demand in kilovars shall be computed similarly to the Monthly Maximum Demand as defined in the Determination of Demands section.

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MINIMUM MONTHLY BILL:

The Minimum Monthly Bill shall be equal to the sum of the Customer Charge, Facilities Charge, and Reactive Demand Adjustment.

SUMMER AND WINTER SEASONS:

The Summer Season is four consecutive months, beginning and effective May 16 and ending September 15, inclusive. The Winter Season is eight consecutive months, beginning and effective September 16 and ending May 15. Customer bills for meter reading periods including one or more days in both seasons will reflect the number of days in each season.

CUSTOMER DEFINITIONS:

1. Secondary Voltage Customer - -Receives service on the low side of the line transformer.

2. Primary Voltage Customer - - Receives service at Primary voltage of 12,000 volts or over but not exceeding 69,000 volts. Customer will own all equipment necessary for transformation including the line transformer.

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Issued: May 1, 2018 ~~June 21, 2017~~
Month Day Year

Effective: ~~June 28, 2017~~
Month Day Year

By: /s/- Darrin R Ives Vice President
Title

THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 45

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 45 Sheet 2

Rate Areas No 2 & 4
(Territory to which schedule is applicable)

which was filed June 21, 2017~~September 10, 2015~~

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 2 of 6 Sheets

MEDIUM GENERAL SERVICE – SPACE HEATING
Schedule MGA (Continued)
~~(Continued)~~

RATE FOR SERVICE AT SECONDARY VOLTAGE: 2MGAE, 2MGAH

1. CUSTOMER CHARGE:
   Customer pays the following charge per month: $54.69

2. FACILITIES CHARGE:
   Per kW of Facilities Demand per month $3.192

3. DEMAND CHARGE:

	Summer Season	Winter Season
Per kW of Billing Demand per month	$4.466~~370~~	$3.103~~036~~

4. ENERGY CHARGE:

Per kWh associated with:	Summer Season	Winter Season
First 180 Hours Use per month	$0.091788~~949~~ per kWh	$0.04846~~712~~ per kWh
Next 180 Hours Use per month	$0.057545~~574~~ per kWh	$0.02935~~853~~ per kWh
Over 360 Hours Use per month	$0.058225~~327~~ per kWh	$0.02551~~481~~ per kWh

~~CUSTOMER CHARGE:~~
~~Customer pays the following charge per month: $49.57~~

~~2B. FACILITIES CHARGE:~~
~~Per kW of Facilities Demand per month $2.893~~

~~3C. DEMAND CHARGE: Summer Season Winter Season~~
~~Summer SeasonWinter Season~~
~~Per kW of Billing Demand per month $4.048 $$2.813~~

~~ENERGY CHARGE:~~
~~Per kWh associated with: Summer Season Winter Season~~
~~First 180 Hours Use per month $0.09178 per kWh $0.04846 per kWh~~
~~Next 180 Hours Use per month $0.05754 per kWh $0.02935 per kWh~~
~~Over 360 Hours Use per month $0.05822 per kWh $0.02551 per kWh~~

Issued: May 1, 2018~~June 21, 2017~~
Month Day Year

Effective: ~~June 28, 2017~~
Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

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THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 45

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 45 Sheet 3

Rate Areas No 2 & 4
(Territory to which schedule is applicable)

which was filed June 21, 2017~~September 10, 2015~~

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 3 of 6 Sheets

MEDIUM GENERAL SERVICE – SPACE HEATING
Schedule MGA (Continued)

RATE FOR SERVICE AT PRIMARY VOLTAGE: 2MGAF, 2MGAG

1. ~~-~~CUSTOMER CHARGE:
   Customer pays the following charge per month: $54.69

2. FACILITIES CHARGE:
   Per kW of Facilities Demand per month $2.702

3. DEMAND CHARGE:

	Summer Season	Winter Season
Per kW of Billing Demand per month	$4.370~~466~~	$3.036~~403~~

4. ENERGY CHARGE:

Per kWh associated with:	Summer Season	Winter Season
First 180 Hours Use per month	$0.08949~~9178~~ per kWh	$0.04712~~846~~ per kWh
Next 180 Hours Use per month	$0.05574~~5754~~ per kWh	$0.02853~~935~~ per kWh
Over 360 Hours Use per month	$0.05327~~822~~ per kWh	$0.02481~~551~~ per kWh

~~CUSTOMER CHARGE:~~

~~Customer pays the following charge per month: $49.57~~

~~2B. FACILITIES CHARGE:~~

~~Per kW of Facilities Demand per month $2.893~~

~~3C. DEMAND CHARGE: Summer Season Winter Season~~

~~Summer SeasonWinter Season~~

~~Per kW of Billing Demand per month $4.048 $$2.813~~

~~ENERGY CHARGE:~~

~~Per kWh associated with: Summer Season Winter Season~~

~~First 180 Hours Use per month $0.09178 per kWh $0.04846 per kWh~~

~~Next 180 Hours Use per month $0.05754 per kWh $0.02935 per kWh~~

~~Over 360 Hours Use per month $0.05822 per kWh $0.02551 per kWh~~

~~A. CUSTOMER CHARGE:~~

~~Customer pays the following charge per month: $49.57~~

Issued: May 1, 2018~~June 21, 2017~~
Month Day Year

Effective: ~~June 28, 2017~~
Month Day Year

By: /s/ Darrin R Ives Vice President
Title

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THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 45

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 45 Sheet 4

Rate Areas No 2 & 4
(Territory to which schedule is applicable)

which was filed June 21, 2017~~September 10, 2015~~

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 4 of 6 Sheets

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MEDIUM GENERAL SERVICE – SPACE HEATING
Schedule MGA (Continued)

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REACTIVE DEMAND ADJUSTMENT (Secondary and Primary Service):

Company may determine the customer's monthly maximum 30-minute reactive demand in kilovars. In each month a charge of $0.~~670~~739 per month shall be made for each kilovar by which such maximum reactive demand is greater than fifty percent (50%) of the customer's Monthly Maximum Demand (kW) in that month. The maximum reactive demand in kilovars shall be computed similarly to the Monthly Maximum Demand as defined in the Determination of Demands section.

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MINIMUM MONTHLY BILL:

The Minimum Monthly Bill shall be equal to the sum of the Customer Charge, Facilities Charge, Demand Charge, and Reactive Demand Adjustment.

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SUMMER AND WINTER SEASONS:

The Summer Season is four consecutive months, beginning and effective May 16 and ending September 15, inclusive. The Winter Season is eight consecutive months, beginning and effective September 16 and ending May 15. Customer bills for meter reading periods including one or more days in both seasons will reflect the number of days in each season.

CUSTOMER DEFINITIONS:

1. Secondary Voltage Customer - Receives service on the low side of the line transformer.
2. Primary Voltage Customer - Receives service at Primary voltage of 12,000 volts or over but not exceeding 69,000 volts. Customer will own all equipment necessary for transformation including the line transformer.

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Issued: May 1, 2018~~June 21, 2017~~
Month Day Year

Effective: ~~June 28, 2017~~
Month Day Year

By: /s/ Darrin R. Ives, Vice President
Title

THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 46

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Rate Areas No 2 & 4
(Territory to which schedule is applicable)

Replacing Schedule 46 Sheet 2

which was filed June 21, 2017~~September 10, 2015~~

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 2 of 6 Sheets

LARGE GENERAL SERVICE – SPACE HEATING
Schedule LGA
(Continued)

RATE FOR SERVICE AT SECONDARY VOLTAGE: 2LGAE, 2LGAH

1. CUSTOMER CHARGE:
Customer pays one of the following charges per month based upon the Facilities Demand:

0 - 999 kW	$114.38
1000 kW or above	$782.28

2. FACILITIES CHARGE:
Per kW of Facilities Demand per month $3.313

3. DEMAND CHARGE:	Summer Season	Winter Season
Per kW of Billing Demand per month	$7.146	$3.302

4. ENERGY CHARGE:		
Per kWh associated with:	Summer Season	Winter Season
First 180 Hours Use per month	$0.06879 per kWh	$0.04812 per kWh
Next 180 Hours Use per month	$0.04916 per kWh	$0.03002 per kWh
Over 360 Hours Use per month	$0.02811 per kWh	$0.02465 per kWh

~~A. CUSTOMER CHARGE:~~

~~Customer pays one of the following charges per month based upon the Facilities Demand:~~

~~0-999 kW $104.62~~
~~1000 kW or above $715.54~~

~~B. FACILITIES CHARGE:~~

~~Per kW of Facilities Demand per month $3.030~~

~~3C. DEMAND CHARGE: Summer Season Winter Season~~
~~Summer SeasonWinter Season~~
~~Per kW of Billing Demand per month $6.536 $3.020~~

~~4D. ENERGY CHARGE:~~

~~Per kWh associated with: Summer Season Winter Season~~
~~First 180 Hours Use per month $0.06879 per kWh~~
~~Next 180 Hours Use per month~~
~~$0.04916 per kWh $0.03002 per kWh~~
~~Over 360 Hours Use per month $0.02811 per kWh~~
~~$0.02465 per kWh~~

Issued: May 1, 2018~~June 21, 2017~~
Month Day Year

Effective: ~~June 28, 2017~~
Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

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THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 46

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 46 Sheet 3

Rate Areas No 2 & 4
(Territory to which schedule is applicable)

which was filed June 21, 2017~~September 10, 2015~~

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 3 of 6 Sheets

LARGE GENERAL SERVICE – SPACE HEATING
Schedule LGA
(Continued)

RATE FOR SERVICE AT PRIMARY VOLTAGE: 2LGAF, 2LGAG

1. CUSTOMER CHARGE:
   Customer pays one of the following charges per month based upon the Facilities Demand:

0 - 999 kW	$114.38
1000 kW or above	$782.28

2. FACILITIES CHARGE:
   Per kW of Facilities Demand per month $2.781

3. DEMAND CHARGE:

	Summer Season	Winter Season
Per kW of Billing Demand per month	$7.012	$3.240

4. ENERGY CHARGE:

Per kWh associated with:	Summer Season	Winter Season
First 180 Hours Use per month	$0.06682 per kWh	$0.04684 per kWh
Next 180 Hours Use per month	$0.04769 per kWh	$0.02903 per kWh
Over 360 Hours Use per month	$0.02705 per kWh	$0.02389 per kWh

~~1. CUSTOMER CHARGE:~~

~~Customer pays one of the following charges per month based upon the Facilities Demand:~~

~~0-999 kW $104.62~~
~~1000 kW or above $715.54~~

~~B. FACILITIES CHARGE:~~

~~Per kW of Facilities Demand per month $2.544~~

~~C. DEMAND CHARGE: Summer Season Winter Season~~
~~Summer Season Winter Season~~
~~Per kW of Billing Demand per month $6.414 $2.964~~

~~D. ENERGY CHARGE:~~

~~Per kWh associated with: Summer Season~~
~~Winter Season~~

~~First 180 Hours Use per month $0~~5444~~.06682 per kWh $0.0~~
~~per kWh~~
~~Next 180 Hours Use per month $0.04769 per kWh $0.02903 per kWh~~
~~Over 360 Hours Use per month $0.02705 per kWh $0.02389 per kWh~~

Issued: May 1, 2018~~June 21, 2017~~
Month Day Year

Effective: ~~June 28, 2017~~
Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

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LARGE GENERAL SERVICE – SPACE HEATING
Schedule LGA

(Continued)

REACTIVE DEMAND ADJUSTMENT (Secondary and Primary Service):

Company may determine the customer's monthly maximum 30-minute reactive demand in kilovars. In each month a charge of $0.~~688~~752 per month shall be made for each kilovar by which such maximum reactive demand is greater than fifty percent (50%) of the customer's Monthly Maximum Demand (kW) in that month. The maximum reactive demand in kilovars shall be computed similarly to the Monthly Maximum Demand as defined in the Determination of Demands section.

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MINIMUM MONTHLY BILL:

The Minimum Monthly Bill shall be equal to the sum of the Customer Charge, Facilities Charge, Demand Charge, and Reactive Demand Adjustment.

SUMMER AND WINTER SEASONS:

The Summer Season is four consecutive months, beginning and effective May 16 and ending September 15, inclusive. The Winter Season is eight consecutive months, beginning and effective September 16 and ending May 15. Customer bills for meter reading periods including one or more days in both seasons will reflect the number of days in each season.

CUSTOMER DEFINITIONS:

1. Secondary Voltage Customer - Receives service on the low side of the line transformer.

2. Primary Voltage Customer - Receives service at Primary voltage of 12,000 volts or over but not exceeding 69,000 volts. Customer will own all equipment necessary for transformation including the line transformer.

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STANDBY SERVICE RIDER
Schedule SSR

APPLICABILITY:

Applicable to each Customer at a single premise(s) with behind-the-meter, on-site parallel Distributed Generation system(s) with a capacity greater than or equal to 100 kilowatts (kW), as a modification to standard electric service supplied under either the tariffed rate schedules of Small General Service (Schedule SGS or SGA), Medium General Service (Schedule MGS or MGA), or Large General Service (Schedule LGS or LGA). Customers must receive service under a standard rate schedule that includes a Facilities Charge and a Demand Charge. Provision of this Rider will be based on the nameplate rating of the Distributed Generation.

Customers with emergency backup, intermittent renewable generation, or energy storage systems are excluded from this Schedule SSR.

DEFINITIONS:

1. Distributed Genera ion – Customer's private, on-site generation that:

   A. is located behind the meter on the Customer's premise(s);

   B. has a nameplate capacity of greater than or equal to 100 KW~~-with the Company;~~

   C. operates in parallel with the Company's system; and

   D. adheres to an applicable interconnection agreement entered into with the Company.

2. Standby Contract Capacity – Shall be the LESSER of:

   A. The sum of nameplate rating(s) of all Customer Distributed Generation systems;

   B. The sum of nameplate rating(s) less any generation on the same premises used exclusively for generation redundancy purposes; and

   C. The number of kilowatts mutually agreed upon by Company as representing the Customer's Standby Capacity requirements based on a Company approved Customer load curtailment plan. Any evidence that the load curtailment plan is not used as intended will result in the Standby Contract Capacity being reset to one of the other alternatives.

~~SEASONAL RECREATIONAL SERVICE~~
~~Schedule SR~~

~~CANCELLED~~

Issued: May 1, 2018~~November 12, 1998~~ (Month Day Year)	~~FILED~~
Effective: ~~For Bills Rendered On or After March 1, 1999~~ (Month Day Year)	~~THE STATE CORPORATION COMMISSION OF KANSAS~~
By: /s/ Darrin R. Ives~~J. L. Latz~~ ~~Senior~~ Vice President (Title)	~~By:~~ Secretary

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STANDBY SERVICE RIDER
Schedule SSR (Continued)

RATES:

1. For Customers with Standby Contract Capacity greater than or equal to 100kW and less than or equal to 2MW

A. Capacity Reservation Charge — An additional charge, based on the size of the Distributed Generation, applied to recover the cost of providing and maintaining the generation and transmission facilities required to support the capacity requirements of the Customer within the Company system.

B. Interconnection Charge — A charge applied in place of the Facility Charge associated with the standard rate, to recover the cost of providing and maintaining the distribution facilities required to interconnect the Customer to the Company system that are normally embedded in the volumetric energy charge of the standard rate.

C. Supplemental Service Charge — A charge for electric service (demand and energy) provided by the Company to the Customer to supplement normal operation of the Customer's Distributed Generation system to meet the Customer's full service requirements. Supplemental Service will be deemed to occur if the Customer's Metered Grid Interconnection Load is positive. Supplemental Service will be supplied at the applicable rates under the standard rate schedule.

D. Excess Generation Credit — If the Customer's Metered Grid Interconnection Load is negative, the excess energy received by the Company system will be credited at the then current Parallel Generation rate, as defined in Schedule PG.

	Small General Service	Medium General Service	Large General Service
Capacity Reservation Charge (per kW of Standby Contract Capacity)	$1.117	$1.117	$1.787
Interconnection Charge (per kW of Standby Contract Capacity)	$6.686	$6.384	$6.626

Supplemental Service Charge — All service will be supplied at the applicable rates under the standard rate schedule.

Excess Generation Credit — Excess energy will be credited at the current Parallel Generation rate as defined in Schedule PG.

STANDBY SERVICE RIDER
Schedule SSR (Continued)

RATES: (Continued)

2. **For Customers with Standby Contract Capacity between greater than 2MW and less than or equal to 10MW**

   A. Minimum Operating Limit — 90% of the Standby Contract Capacity.

   B. Metered Grid Interconnection Load — all metered Customer usage from the Company system. Metering will measure both energy consumed and excess energy, if any, delivered back to the Company system.

   C. Metered Generation Output — all metered output from the Customer's Distributed Generation system.

   D. Total Customer Load — is the Metered Grid Interconnection Load plus the Metered Generation Output.

   E. Standby Service Metering & Administrative Charge — A charge to cover additional meter costs, meter data processing, billing, and administrative costs beyond those covered in the standard tariff.

   F. Supplemental Service Charge — A charge for electric service (demand and energy) provided by the Company to the Customer to supplement normal operation of the Customer's Distributed Generation system to meet the Customer's full service requirements. Supplemental Service will be deemed to occur if the Customer's Total Load is greater than the Metered Generation Output and greater than the Minimum Operating Limit.

   G. Backup Service — Electric service (demand and energy) provided by the Company to Customer premises to replace capacity and energy normally produced by the Customer's Distributed Generation (formerly referred to as Breakdown service). Backup Service will be deemed to occur if the Metered Generation Output is less than the Minimum Operating Limit and less than the Total Customer Load during any time in the Summer period. Seasonal periods are defined in the applicable standard rate schedule.

   H. Maintenance Service — Electric service (demand and energy) provided by the Company to customer premises to replace capacity and energy normally produced by the Customer's Distributed Generation. Maintenance Service will be deemed to occur if the Metered Generation Output is less than the Minimum Operating Limit and less than the Total Customer Load during any time in the Winter period. Seasonal periods are defined in the applicable standard rate schedule.

STANDBY SERVICE RIDER
Schedule SSR (Continued)

RATES: (Continued)

I. Excess Generation Credit — If the Customer's Metered Grid Interconnection Load is negative, the excess energy received by the Company system will be credited at the then current Parallel Generation rate, as defined in Schedule PG.

	Small General Service	**Medium General Service**	**Large General Service**
Standby Service Metering & Administrative Charge (per month)	$140.00	$140.00	$160.00
Capacity Reservation Charge (per kW of Standby Contract Capacity)	$1.117	$1.117	$1.787
Demand Rate (per kW of Monthly Backup or Maintenance Demand):			
Backup Service	$0.186	$0.186	$0.298
Maintenance Service	$0.149	$0.149	$0.238
Energy Charge (per kWh of Monthly Backup or Maintenance Energy):			
Backup Service	$0.14429	$0.09178	$0.06879
Maintenance Service	$0.06337	$0.05754	$0.04916

Supplemental Service Charge: All service will be supplied at the applicable rates under the standard rate schedule.

Excess Generation Credit: Excess energy will be credited at the current Parallel Generation rate, as defined in Schedule PG.

Where:

a) Daily Backup Demand shall equal the Maximum Backup Demand metered during a calendar day;

b) Monthly Backup Demand shall equal the sum of the Daily Backup Demands for the billing period;

STANDBY SERVICE RIDER
Schedule SSR (Continued)

RATES: (Continued)

c) Daily Maintenance Demand shall equal the Maximum Maintenance Demand metered during a calendar day; and

d) Monthly Maintenance Demand shall equal the sum of the Daily Maintenance Demands for billing period.

3. For Customers with Standby Contract Capacity greater than 10MW

Terms for service to Distributed Generation systems of this size will be established by special rate and interconnection agreements. Provisions of the special agreements will address all requirements of systems of this size, including the requirements of the Southwest Power Pool and North American Electric Reliability Corporation. The Company may examine the locational benefit of the Customer Distributed Generation system and consider those benefits in defining the rates charged under this Schedule SSR. As practical, the terms of the special agreements will utilize rates and terms defined within the Company's Commission approved tariffs.

GENERAL PROVISIONS:

The contract term shall be one (1) year, automatically renewable, unless modifications to the Distributed Generation requires a change to the Standby Contract Capacity.

For Distributed Generation larger than 2MW, the Company will install and maintain the necessary suitable meters for measurement of service rendered hereunder, including the Metered Grid Interconnection Load and the Metered Generation Output. The Company may inspect generation logs or other evidence that the Customer's Distributed Generation is being used in accordance with the provisions this Schedule SSR. Upon installation of the metering, the Customer shall initially reimburse the Company for any metering investment costs that are in addition to the cost of metering of standard full requirements retail service.

Distributed Generation systems shall not commence parallel operation until after inspection by the Company and a written interconnection agreement is executed.

All metering occurring for service received and billed under this Schedule SSR will be measured in 15-minute intervals.

STANDBY SERVICE RIDER
Schedule SSR (Continued)

GENERAL PROVISIONS: (Continued)

It is expected that the Customer will perform routine and scheduled maintenance of the Distributed Generation systems during the Winter Season.

The Customer is responsible for timely notification of the Company, in writing, if the Distributed Generation system or load curtailment plan is changed in any what that would impact the Standby Contract Capacity. The Company reserves the right to confirm the Standby Contract Capacity at any time.

If at any time Customer desires to increase demand above the capacity of Company's facilities used in supplying said service due to plant modifications, Customer will sign a new agreement for the full capacity of service required and in accordance with applicable rules governing extension of its distribution system.

In the event a Customer adds Distributed Generation systems after investments are made by the Company in accordance with the Company's Line Extension policy, the Company may require reimbursement by the Customer. Such reimbursement shall be limited to that investment which was incurred within the previous five years and shall be based upon the change in load requirements on the Company's electric system.

In establishing interconnection agreements, parallel operating guidelines, purchase agreements and standby service arrangements with customers in accordance with 18 C.F.R. Sections 292.101 et seq., it is not the Company's intent to simultaneously sell electricity at system-wide average costs and to re-purchase the same electricity at avoided costs. Any condition which allows for this to occur, potentially or actually,shall not be permitted.

REGULATIONS:

Subject to Rules and Regulations filed with the State Regulatory Commission.

RENEWABLE ENERGY RIDER
Schedule RER

PURPOSE:

This Program is designed to provide non-Residential Customers a voluntary opportunity to purchase Renewable Energy, in addition to service provided through a generally available rate, from Renewable Energy sources that the Company contracts.

Following Commission approval of this Rider, the Company will endeavor to procure the Renewable Energy sources necessary to fulfill Customer requests for service under this Program. Pricing and related terms will be updated to reflect these sources.

AVAILABILITY:

Customer accounts receiving Unmetered, Lighting, Net Metering, or Time-of-Use Service are ineligible for this Program while participating in those service agreements. This Program is not available for resale, standby, breakdown, auxiliary, parallel generation, or supplemental service.

Service under this Program is available on a limited and voluntary basis, at the Company's option, to non-Residential Customers currently receiving permanent electric service from the Company through Schedule SGS, MGS, LGS, SGA, MGA, or LGA, with an annual average monthly peak demand greater than 200 kW. At the Company's sole approval, Customers that have an aggregate electric load of at least 2.5 MW based upon peak annual demand and an average of 200 kW per account, or are recognized by the Company as Governmental or Municipal Customers, may combine separate accounts to participate in this Program.

Customers will be enrolled and subscribed on a first-come, first-served basis. Customers applying but not allowed to subscribe due to Renewable Energy resource unavailability will be placed on a waiting list and may be offered the opportunity to subscribe if subscription cancellations or forfeitures occur. Customers approved for aggregation of accounts may choose to participate in part or remain on the list as a consolidated group, depending on resource availability. Participants may cancel their subscription at any time subject to any net cost of the remaining Renewable Energy for the term. Service hereunder is provided to one end-use Customer and may not be redistributed or resold.

Within any limits prescribed by the individual tariffs, the Company will combine the subscription requirements for all Company jurisdictions in executing the power purchase agreement(s) for the Renewable Energy resource. The combined Program will be initially limited to a minimum total load of 100 megawatts (MW) and a maximum total load of 200 MW, split equally between the Company jurisdictions. The Company reserves the right to reapportion the allocation between Companies in response to Customer subscription. The production from the combined power purchase agreement(s) for the Renewable Energy resource will be allocated among the various Company jurisdictions based on the respective subscriptions within that jurisdiction. The limit will be re-evaluated if or when the 200 MW limit is reached. Additional subscriptions will be made available at the sole discretion of the Company.

RENEWABLE ENERGY RIDER
Schedule RER (Continued)

DEFINITION:

For purposes of this Program the following definitions apply:

1. PARTICIPANT — The Customer, specified as the Participant in the Participant Agreement, is the eligible Customer that has received notification of acceptance into the Program.

2. PARTICIPANT AGREEMENT — The agreement between the Company and Customer, utilized for enrollment and establishing the full terms and conditions of the Program. Eligible Customers will be required to sign the Participant Agreement prior to participating in the Program. This agreement may be provided and executed electronically.

3. POWER PURCHASE AGREEMENT (PPA) — an agreement or contract between a resource owner and the Company for renewable energy produced from a specific renewable resource.

4. RENEWABLE ENERGY CREDITS — also known as Renewable Energy Certificates or RECs, represent the environmental attributes associated with one (1) megawatt-hour of renewable electricity generated and delivered to the power grid.

5. RENEWABLE ENERGY — energy produced from a renewable resource as defined in K.S.A. 66-1257, K.A.R. 82-16-1 (l), and associated with this Program. Renewable resources procured will be utilized for this program or similar voluntary, green programs.

6. RESOURCE PROCUREMENT PERIOD — the period of time in which the Company will, if the subscriptions on the waiting list warrant such effort, attempt to obtain a renewable resource to serve the Participation Agreements queued on the waiting list. At a minimum, two Resource Procurement Periods will occur each calendar year

7. SUBSCRIPTION INCREMENT (SI) — An eligible Customer may subscribe and receive energy from a renewable resource in single percentage increments, up to 100% of the Customer's Annual Usage.

RENEWABLE ENERGY RIDER
Schedule RER (Continued)

DEFINITIONS: (Continued)

8. SUBSCRIPTION SHARE (SS) — The proportion of the renewable resource, adjusted for the Renewable Resource Capacity Factor, allocated to the Customer to achieve the desired Subscription Increment amount. The Subscription Share is determined at enrollment and is calculated using the following formula:

$$\mathrm{SS} = \frac{\mathrm{SL}_{\mathrm{MW}}}{\mathrm{RRC}_{\mathrm{MW}}}$$

Where,

$$\mathrm{SL}_{\mathrm{MW}} = \frac{\mathrm{AU}_{\mathrm{MWh}} \cdot \mathrm{SI}}{8{,}760_{\text{hours per year}} \cdot RRC_{factor}}$$

$\mathrm{AU}_{\mathrm{MWh}}$ = Annual Usage; the Customer's actual metered energy usage over the previous 12 monthly billing periods, if available, or Customer's expected metered energy usage over 12 monthly billing period as determined by Company.

$\mathrm{RRC}_{\mathrm{MW}}$ = Renewable Resource Capacity Factor; the average annual capacity of the renewable resource(s) as established by the Company.

$\mathrm{RRC}_{\mathrm{factor}}$ = Renewable Resource Capacity Factor; the average annual capacity factor of the renewable resource(s) as established by Company.

ENROLLMENT:

1. The Customer must submit a completed Participant Agreement to the Company for service under this Program. In the Participant Agreement, the Customer must specify the Subscription Increment to be subscribed.

2. Customers applying for service under this Program must have an account that is not delinquent or in default at the beginning of the Resource Procurement Period and must have completed the required Participant Agreement.

3. Enrollment requests may be submitted to the Company at any time.

4. The Company will review the Participant Agreement and determine if the Customer will be enrolled into the Program.

RENEWABLE ENERGY RIDER
Schedule RER (Continued)

ENROLLMENT: (Continued)

5. In each Resource Procurement Period the Company will match as accurately as possible the combined Renewable Subscription Level of all Participants with a renewable resource, subject to availability. The minimum renewable resource to be acquired will have a capacity of 100 MW and the maximum will depend upon the level of Participation Agreements received. The renewable resource obtained for each Subscriber group may be made up of capacity from multiple renewable resources.

CHARGES AND BILLING:

All charges provided for under, and other terms and conditions of, the Customer's applicable standard service classification(s) tariff shall continue to apply and will continue to be based on actual metered energy use during the Customer's normal billing cycle.

Under this Schedule RER, Customers will receive a Renewable Adjustment (RA), in the form of an additional charge or credit to their standard bill based upon the sale of the metered output of the renewable resource(s) into the wholesale market. The Renewable Adjustment will be calculated as follows:

$$\mathrm{RA} = [\mathrm{RMO_{MWh}} \cdot \mathrm{SS}] \cdot [\mathrm{SC_{\$\ per\ MWh}} - \mathrm{FMP_{\$\ per\ MWh}}]$$

Where,

$\mathrm{RMO_{MWh}}$ = Metered output from the renewable resource at the market node.

$\mathrm{SC_{\$\ per\ MWh}}$= Subscription Charge; the delivered price per MWh of the renewable resource plus the Company Administration Charge of $0.10 per MWh (RMO) for twenty-year term Participant Agreements. For all other Participant Agreements, the Company Administration Charge will be $0.30 per MWh (RMO).

$\mathrm{FMP_{\$\ per\ MWh}}$ = Final Market Price; the accumulation of all applicable market revenues and charges arising from or related to injection of the energy output of the renewable resource into the wholesale energy market in that calendar month at the nearest market node, divided by the actual metered hourly energy production, using the best available data from the regional transmission operator, who facilitates the wholesale marketplace, for the calendar month as of the date the Customer's Renewable Adjustment is being prepared. Alternatively, and at the Company's discretion if determined to be economic, the Company may seek to obtain the necessary transmission to deliver the energy output of the renewable resource to a local, Company market node. If this occurs, the Final Market Price will be calculated based on the accumulation of all applicable market revenues and charges inclusive of this delivery. The energy produced under this alternative will be subject to curtailment by the regional transmission operator. The Final Market Price will be rounded to the nearest cent.

RENEWABLE ENERGY RIDER
Schedule RER (Continued)

CHARGES AND BILLING: (Continued)

The Renewable Adjustment may be applied up to 60 days later than the market transactions to allow for settlement and data processing.

Market revenues and charges may be adjusted to reflect net costs or revenues associated with service under the Program in prior months, for which more recent wholesale market settlement data supersedes the data that was used to calculate initial charges or credits that were assessed to participating Customers.

The Renewable Subscription Charge and the Subscription Share are to be determined at the time the Company obtains the renewable resource to satisfy the Participation Agreement.

Billing and settlement of charges under this Schedule may occur separately from the billing associated with service provided to a Customer's under the Standard Rate Schedules. The Company reserves the right to consolidate account data and process charges collectively to facilitate Customers electing to aggregate subscriptions under this Schedule.

TERM:

Agreements under this Program are available for enrollment for five-year, ten-year, and twenty-year terms. Customers will select the term at time of enrollment and will not be allow to change the term once the renewable resource serving the Customer has been obtained. Customers subscribing to more than 20% of the renewable resource will be required to commit to a minimum term of ten years.

RENEWABLE RESOURCE ENERGY CREDITS:

Renewable Energy Credits associated with energy obtained through this Program will be transferred to the Customer annually or at any time upon Customer request. Alternatively, and if requested, the Company will retire the credits on behalf of the Customer with all costs associated with the registration and retirement borne by the requesting Customer.

RENEWABLE ENERGY RIDER
Schedule RER (Continued)

TRANSFER OR TERMINATION:

Participants who move to another location within the Company's Kansas service territory may request transfer of their subscription, provided the total kWh of the subscribed amount is less than the new location's average annual historical usage (actual or Company estimated). If the existing subscription level exceeds the allowed usage amount at the new location, the subscription will be adjusted down accordingly.

Participants who request termination of the Participation Agreement, or default on the Participation Agreement before the expiration of the term of the Participation Agreement, shall pay to the Company any associated costs and administration associated with termination of the subscribed renewable resource. Such termination charge may be adjusted if and to the extent another Customer requests service under this Schedule and fully assumes the obligation for the purchase of the renewable energy prior to the effective date of the contract amendment or termination; provided, however, Company will not change utilization of its assets and positions to minimize Customer’s costs due to such early termination. The Participant must notify the Company in writing of their request to terminate.

RENEWABLE CONTRACTS SUPPORTING ECONOMIC DEVELOPMENT:

The Company may, at its discretion, enter into an individual agreement with a Customer requesting Renewable Energy to support customer retention or incremental load resulting from the construction or expansion of facilities within the Company's service territory. Depending on the details of the Customer need, the load may be served by the same Renewable Energy resource used for this Program or may result in agreements for additional Renewable Energy resources. The individual terms concerning pricing will be established with the requesting Customer. All agreements are subject to availability and deliverability of Renewable Energy resources and will be structured in such a way as to ensure recovery of all related costs from the requesting Customer.

RENEWABLE ENERGY RIDER
Schedule RER (Continued)

PROGRAM PROVISIONS AND SPECIAL TERMS:

1. In procuring the Renewable Energy, the Company will ensure that Renewable Energy resources utilized under this Program are or have been placed in service after January 1, 2019.

2. At enrollment, the Company will calculate the Customer's demand for the prior twelve-month period to determine eligibility. If twelve months of demand data is not available, the Company may estimate the annual demand to the nearest kW, using a method that includes, but is not limited to, usage by similarly sized properties or engineering estimates.

3. Customers that the Company, at its sole discretion, determines are ineligible will be notified promptly, after such Participant Agreement is denied.

4. Customer participation in this Program may be limited by the Company to balance Customer demand with available qualified Renewable Energy resources, adequate transmission facilities, and capacity.

5. Customers who need to adjust in their commitments due to increases or decreases in electric demand may request such adjustment in writing from the Company. Efforts will be made to accommodate the requested adjustment. The Customer will be responsible for any additional cost incurred to facilitate the adjustment.

6. Any Customer being served or having been served on this Program waives all rights to any billing adjustments arising from a claim that the Customer's service would be or would have been at a lower cost had it not participated in the Program for any period of time.

7. The Company may file a request to discontinue this Program with the Commission at any time in the future. Prior to the termination, the Company will work with the participating Customer to transition them fully from the subscriptions in effect to a Standard Rate Schedule or to an alternate green power option that the Company may be providing at that time. Any Participant who cancels Program participation must wait twelve (12) months after the first billing cycle without a subscription to re-enroll in the Program.

8. Ownership of unsubscribed energy and the associated RECs will be assumed by the Company and incorporated into the energy provided to retail Customers. Unsubscribed amounts will be allocated between the jurisdictions based on the Customer Subscriptions in place at the time of processing.

RENEWABLE ENERGY RIDER
Schedule RER (Continued)

PROGRAM PROVISIONS AND SPECIAL TERMS: (Continued)

9. Ownership of unsubscribed energy and the associated RECs will be assumed by the Company and incorporated into the energy provided to retail Customers. Unsubscribed amounts will be allocated between the jurisdictions based on the Customer Subscriptions in place at the time of processing.

10. The Company shall not be liable to the Customer in the event that the Renewable Energy supplier fails to deliver Renewable Energy to the market and will make reasonable efforts to encourage the Renewable Energy supplier to provide delivery as soon as possible. However, in the event that the Renewable Energy supplier terminates the Renewable Energy contract with the Company, for any reason during the term of contract with the Customers, the Company, at the election of the Customer, shall make reasonable efforts to enter into a new PPA with another Renewable Energy supplier as soon as practicable with the cost of the Renewable Energy to the Customer revised accordingly.

11. Operational and market decisions concerning the renewable resource, including production curtailment due to economic conditions, will be made solely by the regional transmission operator. These decisions could impact the market price received for the renewable resource energy output.

REGULATIONS:

Subject to Rules and Regulations filed with the State Regulatory Commission.

THE STATE CORPORATION COMMISSION OF KANSAS

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)
Rate Areas No 2 & 4
(Territory to which schedule is applicable)

SCHEDULE 66

Replacing Schedule 66 Sheet 1

which was filed November 12, 1998~~June 29, 1989~~

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 1 of 5~~2~~ Sheets

SOLAR SUBSCRIPTION PILOT RIDER~~WATER AND SEWER PUMPING~~

Schedule SSP~~WS~~

PURPOSE:

The purpose of the Solar Subscription Pilot Rider (Program) is to provide a limited number of Customers the opportunity to voluntarily subscribe to the generation output of a solar resource and receive electricity from solar resources. This Program will allow the Company to deploy and evaluate a structure for integrating solar energy directly into service provided to its Customers.

Program Participants will subscribe and pay for Solar Blocks of five hundred (500) watts (W AC) each. Energy produced by the subscribed Solar Blocks will offset an equivalent kWh amount of energy they receive and are billed for under their standard class of service. Approximately 10,000 Solar Blocks will be available for subscription with the initial offering. This program may be expanded to include up to 50 MW of installed solar capacity. Depending on Customer interest, additional solar resources may be built and Solar Blocks made available. Customers will be required to enroll for the Program in advance and each solar resource will be built when 75 percent of the proposed solar resource is committed. If the Company does not receive a sufficient number of subscriptions for the Program, the Company may terminate this Schedule SSP.

AVAILABILITY:

This Rider is available to any Customer currently receiving permanent electric service under the Company's retail rate schedules. Customers must complete the required Participant Agreement and have an account that is not delinquent or in default.

Participants will be enrolled on a first-come, first-served basis. Customers applying but not allowed into the Program due to Solar Block unavailability will be placed on a waiting list and incorporated into the Program in the order they are received. Should Solar Blocks become available due to construction of additional solar resources or subscription cancellations, Customers on the waiting list will be offered the opportunity to subscribe. Subscription hereunder is provided through one meter to one end-use Customer and may not be aggregated, redistributed, or resold.

Total participation of non-residential Customers will be limited to no more than 50 percent of the total solar resource capacity during the first three months of the Program. After three months, and at the Company's sole discretion, all available solar resource capacity may be made available to all eligible Customers.

This Rider may not be combined with any other renewable energy program offered by the Company for the same Customer account.

Customers receiving Unmetered, Lighting, Net Metering, or Time-of-Use Service are ineligible for this Program while participating in those service agreements. This schedule is not available for resale, standby, breakdown, auxiliary, parallel generation, or supplemental service.

~~CANCELLED~~

Issued: May 1, 2018~~November 12, 1998~~ (Month Day Year)	~~FILED~~
Effective: ~~For Bills Rendered On or After March 1, 1999~~ (Month Day Year)	~~THE STATE CORPORATION COMMISSION OF KANSAS~~
By: /s/ Darrin R. Ives~~J. L. Latz~~ ~~Senior~~ Vice President (Title)	~~By:~~ ~~Secretary~~

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THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 66

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 66 Sheet 2

Rate Areas No 2 & 4
(Territory to which schedule is applicable)

which was filed November 12, 1998~~June 29, 1989~~

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 2 of 5~~2~~ Sheets

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SOLAR SUBSCRIPTION PILOT RIDER~~WATER AND SEWER PUMPING~~
Schedule SSP (Continued)~~WS~~

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PRICING:

The Solar Block Subscription Charge for energy sold through this Program is $0.143704 ~~.59~~ per kWh, made up of two costs:

1. The Solar Block cost of $0.11500 per kWh; and
2. The charge of $0.02870 per kWh for interconnection service costs.

The Solar Block cost is defined by the total cost of the solar resources built to serve the program. The interconnection charge is the embedded cost of Transmission and Distribution based on the Company's class cost of service study from the Company's most recent rate case. When an additional solar resource is added to the Program, the levelized cost of the new solar resource will be averaged with the remaining levelized cost of existing solar resource(s) to determine the new price for the cost of the Solar Block. This price may be greater than or less than the previous price. The cost of facilities for distribution interconnection is subject to change in future general rate proceedings, independent from the Solar Block cost.

SUBSCRIPTION LEVEL:

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Participants may subscribe to Solar Blocks that, when combined, are expected to generate up to 50 percent of their annual energy. During initial sign-up, the Customer will designate their desired subscription percentage in increments of 10 percent. The Company will provide to the Customer the number of Solar Blocks necessary to supply their subscription percentage based on the Customer's annual energy usage. The Customer's annual energy usage will be determined in one of two ways. If during initial signup the Customer has 12 consecutive months of usage history at the address where the subscription is being requested, then the annual energy will be the energy consumed during that 12-month usage history. If the Customer does not have 12 consecutive months of usage history at the address where the subscription is being requested, then the annual energy will be estimated by the Company. The calculation for the number of Solar Blocks is equal to the annual energy (in kWh) divided by the expected annual energy production of one block rounded down to the lowest whole number. A Customer must have sufficient annual usage to support subscription of at least one Solar Block.

Until the Company expands its solar energy production beyond the initial 5 MW, the maximum amount any one Customer may subscribe to is 2,500 kW AC of capacity. After the expansion of solar energy production, subscription for any one Customer beyond 2,500 kW AC will be at the Company's discretion. A Participant may change their subscrip ion level only once in any 12-month period after the initial 12-month subscription. In the event there is a significant and regular reduction in Participant metered energy consumption, the Company, at its sole discretion, may adjust the Participant's subscrip ion level.

~~CANCELLED~~

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Issued: May 1, 2018~~November 12, 1998~~ (Month Day Year)	~~FILED~~
Effective: ~~For Bills Rendered On or After March 1, 1999~~ (Month Day Year)	~~THE STATE CORPORATION COMMISSION OF KANSAS~~
By: /s/ Darrin R. Ives~~J. L. Latz~~ ~~Senior~~ Vice President (Title)	~~By:~~ ~~Secretary~~

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SOLAR SUBSCRIPTION PILOT RIDER
Schedule SSP (Continued)

BILLED PURCHASE QUANTITY:

The quantity of energy that will be purchased by a Participant for each monthly billing cycle will be computed as follows:

$$PQ = \frac{SL}{TSC} \cdot AME$$

Where,

PQ = Monthly Purchase Quantity in kWh

SL = Subscription Level in kW AC

TSC = Total Solar System Capacity in kW AC

AME = Actual Monthly Energy Produced by the Solar Resource in kWh.

The Total System Capacity will be re-determined whenever a new solar facility is brought online or an existing solar facility is taken offline.

MONTHLY BILLING:

1. The monthly energy production of the solar resource will be measured and apportioned to each Participant based on their respective subscription share. To facilitate billing, energy production will be applied to the monthly billing one month after it occurs.

2. The Participants share of the solar resource energy production will be subtracted from the metered energy consumed by the Participant for the billing month. Should the solar resource energy production amount for a given month be larger than the Participant's metered energy consumption, the net energy will be zero for that month.

3. Any remaining metered energy consumption will be billed under the rates associated with the Participant's standard rate schedule, including all applicable riders and charges

4. Other, non-energy charges defined by the standard rate schedule are not impacted by the Solar Block subscription and will be billed to the Participant.

5. The entire bill amount, inclusive of all standard rate charges and Program charges, must be paid according to the payment terms set forth in the Company Rules and Regulations.

SOLAR SUBSCRIPTION PILOT RIDER
Schedule SSP (Continued)

WAITING LIST:

If at the time of subscription request a Customer's desired subscription level is greater than the available energy of the solar resource, then the Customer may elect to be placed on a waiting list.

Customers will be offered an opportunity to subscribe in the order that they are placed on the waiting list, only if available capacity is greater than the customer's desired subscription level. If the available capacity is less than the Customer's desired subscription level, the Customer will be offered the opportunity to subscribe to the remaining available capacity. If the Customer does not wish to participate at this lower than desired subscription level, then the next Customer on the waiting list will be checked for subscription availability.

SUBSCRIPTION TERM:

Participants must remain in the Program for one year, as measured from the first bill received under this Rider.

Non-residential Participants who subscribe to 25 percent of the available Solar Blocks for a given solar resource, are required to commit to a minimum term of five years.

PROGRAM PROVISIONS AND SPECIAL TERMS:

1. All rights to the renewable energy certificates (REC) associated with the generation output of the solar facility will be retired by the Company on behalf of Participants.

2. Any Participant being served or having been served on this Program waives all rights to any billing adjustments arising from a claim that the Participant's service would be or would have been at a lower cost had it not participated in the Program for any period of time.

3. Participants who move to another location within the Company's Missouri service territory may transfer their subscription, provided the total kWhs of the subscribed amount is not more than the new location's allowed subscription level (actual or estimated). If the subscription level exceeds the allowed amount at the new location, the subscription will be adjusted down accordingly.

4. Participants must notify the Company in writing of their intent to transfer any subscription(s). Transfers will only be effective if the Transferee satisfies the terms and conditions applicable to the subscription and signs the Participant Agreement and assumes all responsibilities associated therewith.

SOLAR SUBSCRIPTION PILOT RIDER
Schedule SSP (Continued)

PROGRAM PROVISIONS AND SPECIAL TERMS: (Continued)

5. Customers that subscribe will continue as Participants until they cancel their subscription or the Program is terminated. New subscriptions and cancelations require notice 20 days prior to the end of the Participant's billing cycle and will take effect at the beginning of the next applicable billing cycle.

6. Upon cancelation of a Participant's service, Participants may transfer their entire subscription to another eligible Participant's service agreement, including non-profits, for a $25 fee. Participants with more than one Solar Block may transfer their Solar Block subscriptions in whole subscription increments to one or more Eligible Customers for a $25 fee per transfer.

7. Any Participant who cancels Program participation must wait 12 months after the first billing cycle without a subscription to re-enroll in the Program.

8. Ownership of unsubscribed Solar Blocks and the associated RECs will be assumed by the Company and incorporated into the energy provided to retail Customers.

ADJUSTMENTS AND SURCHARGES:

The Rates hereunder are subject to adjustment as provided in the following schedules:

- Energy Cost Adjustment (ECA)
- Energy Efficiency Rider (EER)
- Property Tax Surcharge (PTS)
- Tax Adjustment (TA)
- Transmission Delivery Charge (TDC)

REGULATIONS:

Subject to Rules and Regulations filed with the State Regulatory Commission.

Issued: May 1, 2018
Month Day Year

Effective: ______
Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 69

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 69 Sheet 1

Rate Areas 2 & 4
(Territory to which schedule is applicable)

which was filed June 21, 2017~~September 10, 2015~~

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 1 of 2 Sheets

MUNICIPAL ORNAMENTAL STREET LIGHTING SERVICE
Schedule MOL

AVAILABILITY:

Available for ornamental street lighting service through a Company-owned Street Lighting System within corporate limits of a municipality.

TERM OF CONTRACT:

Contracts under this schedule shall be for a period of not less than ten years from the effective date thereof. Termination prior to end of 10-year period results in a one-time charge equal to the Company's actual investment less depreciation.

RATE: (High Pressure Sodium Vapor)~~:~~ 2MOSL
(Light Emitting Diode (LED)) 2MOLL

1.0 Basic Installa ion:
Street lamps equipped with ornamental luminaire on ornamental poles served from underground extensions not in excess of 200 feet per unit:

	Size of Lamp	Monthly kWh	Total Charge, per Lamp, per Month, Under Sod	Total Charge, per Lamp, per Month, Under Concrete
1.1	9500 Lumen High Pressure Sodium (100-watt)	49	$~~62.87~~64.66	$~~91.88~~94.50
1.2	16000 Lumen High Pressure Sodium (150-watt)	67	$65.72	$95.89
1.3	4300 Lumen LED (Class K) (Acorn Style)	26	$61.83	$90.84
1.4	10000 Lumen LED (Class L) (Acorn Style)	41	$62.32~~63.90~~	$91.65~~93.23~~

Company inventory availability as follows [1,2]:

1. Luminaire: Standard Ornamental
2. Post: 12-foot cast aluminum with 4 inch diameter shaft
3. Base: Standard Screw-in Base

(1) If any equipment becomes obsolete, then new installations will be accomplished with the most appropriate available equipment by mutual agreement of the Company and the Municipality.
(2) Any changes to above listed standard equipment will incur additional monthly facilities charges.

Lumens for LED luminaires may vary ±12% due to differences between luminaire suppliers.

NOTE: Hight Pressure Sodium w~~W~~attage specifications do not include wattage required for ballast.

Issued: May 1, 2018~~June 21, 2017~~
Month Day Year

Effective: ~~June 28, 2017~~
Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

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THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 70

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 70 Sheet 1

Rate Areas 2 & 4
(Territory to which schedule is applicable)

which was filed June 21, 2017~~September 10, 2015~~

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 1 of 2~~1~~ Sheets

OFF-PEAK LIGHTING SERVICE
Schedule LS

AVAILABILITY:

For metered, secondary voltage, electric outdoor lighting service solely to a municipality or governmental entities for purposes of enhancing security and/or illuminating streets, parks, athletic fields, parking lots, or other outdoor facilities. At the Company's discretion, the metering requirement may be eliminated where it is impractical or difficult to install and read meters. Usage for unmetered lights will be estimated using wattage ratings and hours usage. The lamps served under this~~through one meter for~~ schedule~~lighting service~~ must be~~which is~~ controlled with a photo-electric cell or other positive controlled device which restricts service to non-daylight hours. Governmental entities qualifying for service under this schedule include departments, agencies, and subdivisions of the United States, the State of Kansas, counties, municipalities, and school districts.~~At the Company's discretion, the metering requirement may be eliminated for some unmetered lights connected prior to March 1, 1999, where it is economical for the Company to do so. Usage for unmetered lights will be estimated using wattage ratings and hours usage.~~

Service to privately-owned lights or Company-owned street lights shall not be supplied under this schedule. Standby, breakdown, supplementary, temporary or seasonal service will not be supplied under this schedule.

TERM OF CONTRACT:

Contracts under this schedule shall be for a period of not less than one year from the effective date thereof.

RATE: 2LS1E

$0.~~05798~~05963 per kWh for all kWh per month.

~~Monthly service facilities charge shall be equal to 1.50% of the total installed cost of the Company's lighting service facilities in excess of ordinary metering and transformation facilities as determined at the time of any installation, extension, addition or betterment of the Company's service facilities. The monthly service facilities charge shall remain in effect until the Company's investment in such facilities is recovered.~~

~~**ADJUSTMENTS AND SURCHARGES:**~~

~~The rates hereunder are subject to adjustment as provided in the following schedules:~~

- ~~Energy Cost Adjustment (ECA)~~
- ~~Property Tax Surcharge (PTS)~~
- ~~Tax Adjustment (TA)~~
- ~~Transmission Delivery Charge (TDC)~~

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Issued: May 1, 2018~~June 21, 2017~~
Month Day Year

Effective: ~~June 28, 2017~~
Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

OFF-PEAK LIGHTING SERVICE
Schedule LS (Continued)

RATE: KSOLL, 2LSIE (Unmetered)

1. The Customer will pay a monthly charge for all lighting service as follows:

A.	Customer Charge	\$21.70
B.	Energy Charge (All usage)	\$0.05963

2. The monthly kWh usage for unmetered service will be calculated as follows:

$$\text{kWh Usage} = \frac{\text{Total Watts } \cdot \text{MBH} \cdot \text{BLF}}{1{,}000}$$

MBH = Monthly Burning Hours ($\frac{4{,}100\ hours}{12}$)
BLF = Ballast Loss Factor; one (1) plus the manufacturer's published ballast loss percentage (expressed as a decimal fraction) for the installed unit if applicable.

3. For unmetered service, the Company shall have the right to verify or audit the type, wattage, and number of lights installed.

ADJUSTMENTS AND SURCHARGES:

The rates hereunder are subject to adjustment as provided in the following schedules:

- Energy Cost Adjustment (ECA)
- Property Tax Surcharge (PTS)
- Tax Adjustment (TA)
- Transmission Delivery Charge (TDC)

REGULATIONS:

Subject to Rules and Regulations filed with the State Regulatory Commission.

THE STATE CORPORATION COMMISSION OF KANSAS

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)
Rate Areas 2 & 4
(Territory to which schedule is applicable)

SCHEDULE 71

Replacing Schedule 71 Sheet 1

which was filed June 21, 2017~~September 10, 2015~~

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No supplement or separate understanding shall modify the tariff as shown hereon

PRIVATE UNMETERED PROTECTIVE LIGHTING SERVICE (FROZEN)
Schedule AL

AVAILABILITY:

For unmetered protective lighting service for private entrances, exits, yards, driveways, streets, alleys, walkways and other all-night outdoor private areas on existing customer's premises. Not available for municipal street, park or other public lighting, or for temporary service.

RATE: 2ALDA, 2ALDE

1~~A~~. Base Charge:

The monthly rate for each private lighting unit installed on an existing wood pole and using existing secondary circuits is as follows:

	Monthly kWh	Area Lighting	Flood Lighting
5800 Lumen High Pressure Sodium Unit (70-watt)	34	$~~14.53~~14.94	
8600 Lumen Mercury Vapor Unit* (175-watt)	71	$~~15.18~~15.61	
16000 Lumen High Pressure Sodium Unit (150-watt)	67	$~~24.07~~24.76	
22500 Lumen Mercury Vapor Unit* (400-watt)	157	$~~24.47~~25.17	
22500 Lumen Mercury Vapor Unit* (400-watt)	157		$~~26.04~~26.78
50000 Lumen High Pressure Sodium Unit (400-watt)	162		$~~41.01~~42.18
63000 Lumen Mercury Vapor Unit* (1000-watt)	372		$~~44.53~~45.80

* Limited to the units in service September 30, 1985, until removed.

NOTE: Wattage specifications do not include wattage required for ballast.

2~~B~~. Additional Charges:

If an extension of the Company's secondary circuit or a new circuit is required either on or off the customer's premises to supply service hereunder at the location or locations desired on the customer's premises, the above monthly rate shall be increased as follows:

Each 30-foot ornamental steel pole installed	$ ~~10.94~~11.25
Each 35-foot ornamental steel pole installed	$ ~~12.01~~12.35

Issued: May 1, 2018~~June 21, 2017~~
Month Day Year

Effective: ~~June 28, 2017~~
Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

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PRIVATE UNMETERED PROTECTIVE LIGHTING SERVICE (FROZEN)
Schedule AL (Continued)

RATE: 2ALDA, 2ALDE (Continued)

2~~B~~. Additional Charges: (C~~c~~ontinued)

Each 30-foot wood pole installed	$~~6.77~~6.96
Each 35-foot wood pole installed	$~~7.84~~8.06
Each overhead span of circuit installed	$~~2.11~~2.17

If the installa ion of additional transformer facilities is required to supply service hereunder, the above monthly rate shall be increased by a charge equal to one and three-fourths percent of the Company's total investment in such additional transformer facilities.

If the customer requires underground service, the customer will be responsible for installing all underground ductwork in conformance with Company specifications and the Company will be responsible for installing cable and making the connection to Company facilities. There will be an additional $~~2.97~~3.05 per month charge for each underground lighting unit served. If the underground conduit exceeds 300 feet in length, there will be an additional charge of $~~2.97~~3.05 per month per 300 foot length, or fraction thereof.

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BILLING:

The charges for service under this schedule shall appear as a separate item on the customer's regular electric service bill.

TERM:

The minimum initial term under this rate schedule shall be one year. However, if the private lighting installation requires extension of the Company's service facilities of more than one pole and one span of circuit or the installation by the Company of additional transformer facilities, the customer shall be required to execute a service agreement with an initial term of three years.

UNEXPIRED CONTRACT CHARGES:

If the contracting customer terminates service during the initial term of the agreement, and a succeeding customer does not assume the same agreement for private lighting service at the same service address, the contracting customer shall pay to the Company unexpired contract charges equal to the monthly rate times the number of remaining months in the contract period.

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PRIVATE UNMETERED PROTECTIVE LIGHTING SERVICE (FROZEN)
Schedule AL (Continued)

SPECIAL PROVISIONS:

1~~A~~. The customer shall provide, without cost to the Company, all permits, consents, or easements necessary for the erection, maintenance, and operation of the Company's facilities.

2~~B~~. The Company reserves the right to restrict installations served under this schedule to areas easily accessible by service truck.

3~~C~~. All facilities required for service under this schedule will be furnished, owned, installed and maintained by the Company in accordance with the presently effective Construction Standards of the Company.

4~~D~~. Extension of the Company's secondary circuit under this schedule to more than one pole and one span of wire for service hereunder to any customer is subject to prior study and approval by the Company.

5~~E~~. The Company will not be obligated to patrol to determine outages or required maintenance of the facilities used for service under this schedule. Upon notification of any outage or required maintenance of facilities used hereunder, the Company will restore normal service as soon as practicable but only during regularly scheduled working hours. No reduction in billing shall be allowed for any outage of less than ten working days after notification of Company.

6~~F~~. Upon receipt of written request from the customer, the Company will, insofar as it may be practicable and permissible, relocate, replace or change its facilities used or to be used in rendering service to the customer under this schedule, provided the customer agrees in writing to reimburse the Company upon being billed for the Company's cost so incurred.

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THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 71

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 71 Sheet 4

Rate Areas 2 & 4
(Territory to which schedule is applicable)

which was filed September 10, 2015~~December 13, 2012~~

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 4 of 4 Sheets

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PRIVATE UNMETERED PROTECTIVE LIGHTING SERVICE (FROZEN)
Schedule AL (Continued)

SPECIAL PROVISIONS: ~~(~~(C~~c~~ontinued)

7~~G~~. If a customer who has agreed to a specific lighting unit requests to change to a different lighting unit, the customer shall pay the labor cost for the removal of the existing unit and the Base Charge for the new unit shall be applicable thereafter.

8~~H~~. All existing mercury vapor lights shall be changed to high pressure sodium lights when maintenance or change out is required. When these change outs occur, the customer charge will be changed to the high pressure sodium rate.

9~~I~~. When the Company changes mercury vapor lights, all lights at the same location will be changed to high pressure sodium. The 22500 lumen mercury vapor area light will be retained. However, the customer may change to any other light under Section A.

ADJUSTMENTS AND SURCHARGES:

The rates hereunder are subject to adjustment as provided in the following schedules:

- Energy Cost Adjustment (ECA)
- Property Tax Surcharge (PTS)
- Tax Adjustment (TA)
- Transmission Delivery Charge (TDC)

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REGULATIONS:

Subject to Rules and Regulations filed with the State Regulatory Commission.

Issued: May 1, 2018~~September 10, 2015~~
Month Day Year

Effective: ~~October 1, 2015~~
Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 72

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule ~~2~~-72 Sheet 1

Rate Area 2 & 4
(Territory to which schedule is applicable)

which was filed September 30, 1985~~April 13, 1979~~

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 1 of 42 Sheets

PRIVATE UNMETERED LED LIGHTING SERVICE
Schedule PL

AVAILABILITY:

For unmetered lighting service for private entrances, exits, yards, driveways, streets, alleys, walkways and other all-night outdoor private areas on existing Customer's premises. Not available for municipal street lighting or for temporary service. Customers will be required to sign an Application for Private Lighting Service before service will be provided.

RATE: 2ALLA, 2ALLE

1. Base Charge:

The monthly rate for each private lighting unit installed using existing secondary circuits is as follows:

	Monthly kWh	Monthly Rate
4,500 Lumen LED (Type A-PAL)	11	$11.01
8,000 Lumen LED (Type C-PAL)	21	$14.40
14,000 Lumen LED (Type D-PAL)	39	$19.06
10,000 Lumen LED (Type C–FL)	27	$14.40
23,000 Lumen LED (Type E–FL)	68	$26.37
45,000 Lumen LED (Type F–FL)	134	$51.53

Lumens for LED luminaires may vary ±12% due to differences between luminaire suppliers.

2. Additional Charges:

Optional Equipment: The following rates for Optional Equipment may be added to the rate for basic installation.

If an extension of the Company's secondary circuit or a new circuit is required either on or off the Customer's premises to supply service hereunder at the location or locations desired on the Customer's premises, the above monthly rate shall be increased as follows:

Each 30-foot metal pole installed (SP30)	$10.94
Each 35-foot metal pole installed (SP35)	$12.01
Each 30-foot wood pole installed (WP30)	$6.77
Each 35-foot wood pole installed (WP35)	$7.84
Each overhead span of circuit installed (SPAN)	$2.11
Optional Breakaway Base (for metal pole only) (BKWY)	$3.48

If the installation of additional transformer facilities is required to supply service hereunder, the above monthly rate shall be increased by a charge equal to one and three-fourths percent (1¾%) of the Company's total investment in such additional transformer facilities.

Issued: May 1, 2018~~September 30, 1985~~
Month Day Year

Effective: ~~September 30, 1985~~
Month Day Year

By: /s/ Darrin R. Ives~~L. C. Rasmussen,~~ Vice
Title

~~FILED September 30, 1985~~

~~THE STATE CORPORATION COMMISSION OF KANSAS~~

~~By: Judith McConnell~~
~~Secretary~~

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PRIVATE UNMETERED LED LIGHTING SERVICE
Schedule PL (Continued)

RATE: 2ALLA, 2ALLE (C~~c~~ontinued)

2. Additional Charges: (C~~c~~ontinued)

If the Customer requires underground service, the Customer will be responsible for installing all underground duct work in conformance with Company specifications and the Company will be responsible for installing cable and making the connection to Company facilities. There will be an additional $2.97 per month charge for each underground lighting unit served up to a maximum of 300 feet of underground conduit per lighting unit (U300).

BILLING:

The charges for service under this schedule shall appear as a separate item on the Customer's regular electric service bill.

TERM:

The minimum initial term under this rate schedule shall be one year for the LED Luminaire. However, if the private lighting installation requires a wood pole or the installation by the Company of additional transformer facilities, the Customer shall be required to execute a service agreement with an initial term of three years. If the Customer wants a metal pole installed, the Customer shall be required to execute a service agreement with an initial term of five years.

UNEXPIRED CONTRACT CHARGES:

If the contracting Customer terminates service during the initial term of the agreement, and a succeeding Customer does not assume the same agreement for private lighting service at the same service address, the contracting Customer shall pay to the Company unexpired contract charges equal to the monthly rate times the number of remaining months in the contract period.

REPLACEMENT OF UNITS:

The Company has the right to replace existing fixtures in need of repair or replacement (or on poles in need of repair or replacement) with equivalent Light Emitting Diode (LED) luminaires. Customers will be given the opportunity to decline the replacement and remove the fixture entirely.

~~COMMERCIAL STREET LIGHTING~~

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PRIVATE UNMETERED LED LIGHTING SERVICE
Schedule PL (Continued)

SPECIAL PROVISIONS:

1. The Customer shall provide, without cost to the Company, all permits, consents, or easements necessary for the erection, maintenance, and operation of the Company's facilities.

2. The Company reserves the right to restrict installations served under this schedule to areas easily accessible by service truck.

3. All facilities required for service under this schedule will be furnished, owned, installed and maintained by the Company in accordance with the presently effective Construction Standards of the Company.

4. Extension of the Company's secondary circuit under this schedule more than one pole and one span of wire for service hereunder to any Customer is subject to prior study and approval by the Company.

5. The Company will not be obligated to patrol to determine outages or required maintenance of the facilities used for service under this schedule. Upon notification of any outage or required maintenance of facilities used hereunder, the Company will restore normal service as soon as practicable but only during regularly scheduled working hours. No reduction in billing shall be allowed for any outage of less than ten working days after notification of Company.

6. Upon receipt of written request from the Customer, the Company will, insofar as it may be practicable and permissible, relocate, replace or change its non-lighting facilities used or to be used in rendering service to the Customer under this schedule, provided the Customer agrees in writing to reimburse the Company upon being billed for the Company's cost so incurred.

7. If a Customer who has agreed to a specific lighting unit, requests a change to a different lighting unit during the initial term of the contract, the Customer shall pay the labor cost for the removal of the existing unit and the Base Charge for the new unit shall be applicable thereafter.

8. Company shall select style and make of lighting facilities provided within each type system for which rates are listed. Lighting will not be installed on poles or structures not owned or leased by Company.

PRIVATE UNMETERED LED LIGHTING SERVICE
Schedule PL (Continued)

OPERATING HOURS:

Unless otherwise stated, luminaires operate each and every day of the year from about one-half hour after sunset to about one-half hour before sunrise, approximately 4100 hours per year.

ADJUSTMENTS AND SURCHARGES:

The Rates hereunder are subject to adjustment as provided in the following schedules:

- Energy Cost Adjustment (ECA)
- Property Tax Surcharge (PTS)
- Tax Adjustment (TA)
- Transmission Delivery Charge (TDC)

REGULATIONS:

Subject to Rules and Regulations filed with the State Regulatory Commission.

THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 73

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 73 Sheet 1

Rate Areas 2 & 4
(Territory to which schedule is applicable)

which was filed June 21, 2017~~September 10, 2015~~

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 1 of 7~~5~~ Sheets

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MUNICIPAL STREET LIGHTING SERVICE
Schedule ML

AVAILABILITY:

Available for street lighting service through a Company-owned Street Lighting System within corporate limits of a municipality.

TERM OF CONTRACT:

Contracts under this schedule shall be for a period of not less than ten years from the effective date thereof.

RATE (Incandescent): 2MLIL (FROZEN)

1.0 Street lamps equipped with a hood and reflector, supported on a wood pole or existing trolley pole and supplied from overhead circuits by an extension not in excess of 500 feet per unit: (Code X)

	Size of Lamp	Monthly kWh	Rate per Lamp per Year
1.1~~2~~	2500 Lumen (187-watt)*	64	$~~125.28~~128.88

2.0 Street lamps equipped with a hood, reflector, and refractor, on wood poles served overhead by an extension not in excess of 500 feet per unit: (Code IWT)

	Size of Lamp	Monthly kWh	Rate per Lamp per Year
2.1	4000 Lumen (269-watt)*	92	$~~212.04~~218.04
2.2	6000 Lumen (337-watt)*	115	$~~236.88~~243.60

*Limited to the units in service on December 28, 1972, until removed.

Issued: ~~June 21, 2017~~May 1, 2018
Month Day Year

Effective: ~~June 28, 2017~~
Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 73

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 73 Sheet 2

Rate Areas 2 & 4
(Territory to which schedule is applicable)

which was filed June 21, 2017~~September 10, 2015~~

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 2 of 7~~5~~ Sheets

MUNICIPAL STREET LIGHTING SERVICE
Schedule ML (Continued)

RATE (Incandescent): 2MLIL (FROZEN) (C~~c~~ontinued)

3~~4~~.0 Street lamps equipped with hood, reflector, and refractor, on ornamental steel poles served underground by an extension not in excess of 300 feet per unit:

	Size of Lamp	Monthly kWh	Rate per Lamp per Year
3~~4~~.1	4000 Lumen (269-watt) Under Sod* (1)	92	$~~332.64~~342.12

(1) Code ISE

* Limited to the units in service on December 28, 1972, until removed.

Issued: May 1, 2018~~June 21, 2017~~
Month Day Year

Effective: ~~June 28, 2017~~
Month Day Year

By: /s/ Darrin R. Ives Vice President
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THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 73

KANSAS CITY POWER & LIGHT COMPANY

(Name of Issuing Utility)

Replacing Schedule 73 Sheet 3

Rate Areas 2 & 4

(Territory to which schedule is applicable)

which was filed June 21, 2017~~September 10, 2015~~

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No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 3 of 7~~5~~ Sheets

MUNICIPAL STREET LIGHTING SERVICE

Schedule ML (Continued)

RATE (Customer Owned): 2MLCL (FROZEN)

4~~6~~.0 Street lamps equipped with a hood, reflector, and refractor, owned and installed by customer, maintained and controlled by the Company, served overhead or underground:

	Size of Lamp	Monthly kWh	Rate per Lamp per Year
4~~6~~.1~~4~~	16000 Lumen Limited Maintenance (150-watt)(1)	67	$~~204.72~~210.60
4~~6~~.2~~5~~	27500 Lumen Limited Maintenance (250-watt)(1)	109	$~~268.32~~276.00

(1) Code LMX

~~**RATE (Mercury Vapor): 2MLML**~~

~~7.0 Post top, low mounting street lamps with canopy and refractor mounted on 14 foot posts served underground by an extension under sod not in excess of 200 feet per unit. (Code PTE)~~

	Size of Lamp	Monthly kWh	Rate per Lamp per Year
~~7.1~~	~~9600 Lumen** (175 watt)~~	~~71~~	~~$289.44~~

~~** Limited to the units in service on September 30, 1985, until removed.~~

~~**NOTE:** Wattage specifications do not include wattage required for ballast.~~

Issued: May 1, 2018~~June 21, 2017~~
Month Day Year

Effective: ~~June 28, 2017~~
Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 73

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 73 Sheet 4

Rate Areas 2 & 4
(Territory to which schedule is applicable)

which was filed June 21, 2017~~September 10, 2015~~

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 4 of 7~~5~~ Sheets

MUNICIPAL STREET LIGHTING SERVICE
Schedule ML ~~L~~ (Continued)

RATE (Mercury Vapor and High Pressure Sodium Vapor): 2MLML, 2MLSK, 2MLSL (FROZEN)

5~~8~~.0 Basic Installation:
Street lamps equipped with hood, reflector, and refractor, on wood poles served from overhead circuits by an extension not in excess of 200 feet per unit: (Code OW)

	Size of Lamp	Monthly kWh	Lumen Charge per Lamp per Year(1)	Total Charge per Lamp per Year(1)
5~~8~~.1	8600 Lumen Mercury Vapor (175-watt)*	71	~~$45.84~~47.16	$~~208.20~~214.08
5~~8~~.2	12100 Lumen Mercury Vapor (250-watt)*	101	$~~64.20~~66.00	$~~226.56~~233.04
5~~8~~.3	22500 Lumen Mercury Vapor (400-watt)*	157	$~~122.04~~ 125.52	$~~284.40~~292.56
5~~8~~.4~~5~~	5800 Lumen High Pressure Sodium (70-watt)***	34	$~~32.04~~33.00	$~~194.40~~199.92
5~~8~~.5~~6~~	9500 Lumen High Pressure Sodium (100-watt)***	49	$~~46.20~~47.52	$~~208.56~~214.56
5~~8~~.6~~7~~	16000 Lumen High Pressure Sodium (150-watt)***	67	$~~64.80~~66.60	$~~227.16~~233.64
5~~8~~.7~~8~~	27500 Lumen High Pressure Sodium (250-watt)***	109	$~~122.40~~125.88	$~~284.76~~292.92
5~~8~~.8~~9~~	50000 Lumen High Pressure Sodium (400-watt)***	162	$~~285.72~~293.88	$~~448.08~~460.80

(1)Rates above are based on a Base Unit Charge of $~~162.36~~167.04 plus a Lumen Charge as stated above. Twin units will be billed at one and one-half (1 1/2) times the Base Unit Charge plus (2) times the appropriate Lumen Charge. KWh usage for twin lamps is two times the single monthly kWh.

6~~9~~.0 Optional Equipment: The following rates for Optional Equipment shall be added to the rate for Basic Installa ion listed in 8.0 above for Mercury Vapor and High Pressure Sodium Vapor installations only.

6~~9~~.1 Ornamental steel pole instead of wood pole, additional charge per unit per year $~~45.36~~46.68. (New installations are available with underground service only).

6~~9~~.2 Laminated wood pole instead of wood pole.** (Available with underground service only). Additional charge per unit per year $~~95.16~~97.92.

6~~9~~.3 Aluminum pole instead of a wood pole, additional charge per unit per year $~~93.12~~95.76. (Available with underground service only).

Issued: May 1, 2018~~June 21, 2017~~
Month Day Year

Effective: ~~June 28, 2017~~
Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

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THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 73

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 73 Sheet 5

Rate Areas 2 & 4
(Territory to which schedule is applicable)

which was filed June 21, 2017~~September 10, 2015~~

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 5 of 7~~5~~ Sheets

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MUNICIPAL STREET LIGHTING SERVICE
Schedule ML~~-L~~ (Continued)

RATE (Mercury Vapor and High Pressure Sodium Vapor): 2MLML, 2MLSK, 2MLSL (FROZEN) (Continued)

~~Optional Equipment (continued)~~

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6~~9~~.4 Underground service extension, under sod, not in excess of 200 feet. Additional charge per unit per year $~~79.68~~81.96.

6~~9~~.5 Underground service extension under concrete, not in excess of 200 feet. Additional charge per unit per year $~~431.64~~444.00.

6~~9~~.6 Breakaway base. Additional charge per unit per year $~~41.76~~42.96. (Available with underground service only).

6~~9~~.7 Special black square luminaire,* instead of basic installation luminaire. (Available with underground service only). Additional charge per unit per year $~~91.68~~94.32.

RATE (LED): 2MLLL

7.0 Basic Installation:

Street luminaires on new wood poles serviced from overhead circuits by a new extension not in excess of 200 feet per unit: (Code OW)

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	Size and Type of Luminaire	Monthly kWh	Rate per Luminaire per Month[(2), (3)]
7.1	5000 Lumen LED (Class A)(Type V pattern)[(1)]	16	$16.20
7.2	5000 Lumen LED (Class B)(Type II pattern)[(1)]	16	$16.20
7.3	7500 Lumen LED (Class C)(Type III pattern)[(1)]	23	$18.93
7.4	12500 Lumen LED (Class D)(Type III pattern)[(1)]	36	$23.73
7.5	24500 Lumen LED (Class E)(Type III pattern)[(1)]	74	$25.36

[(1)] Lumens for LED luminaires may vary ±12% due to differences between lamp suppliers.
[(2)] Twin luminaires shall be two times the rate per single luminaire per month.
[(3)] Existing LED luminaires installed under the MARC Pilot (Schedule ML-LED) will be converted to these rates based on their installed lumen size.

~~**REPLACEMENT OF UNITS:**~~

~~Existing street lamps shall be replaced at the same pole location with a different type of standard unit installation only by mutual agreement of the Company and the Municipality. The Company has the right to replace existing incandescent and mercury vapor street lamps in need of repair or replacement (or on poles in need of repair or replacement) with equivalent high pressure sodium vapor street lamps.~~

~~**STANDARD UNITS:**~~

~~Standard street lamps are those mercury vapor or high pressure sodium vapor units for which a rate is stated except those with an X designation in the type code.~~

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By: /s/ Darrin R. Ives Vice President
Title

MUNICIPAL STREET LIGHTING SERVICE
Schedule ML (Continued)

RATE (LED): 2MLLL (Continued)

8.0 Street luminaires on short bracket arm and existing wood poles served from existing overhead circuits: (Code EW)

	Size and Type of Luminaire–	Monthly kWh	Rate per Luminaire per Month
8.1	5000 Lumen LED (Class A)(Type V pattern)[1]	16	$16.20
8.2	5000 Lumen LED (Class B)(Type II pattern)[1]	16	$16.20
8.3	7500 Lumen LED (Class C)(Type III pattern)[1]	23	$18.93
8.4	12500 Lumen LED (Class D)(Type III pattern)[1]	36	$23.73
8.5	24500 Lumen LED (Class E)(Type III pattern)[1]	74	$25.36

[1]Lumens for LED luminaires may vary ±12% due to differences between lamp suppliers.

9.0 Optional Equipment: The following rates for Optional Equipment shall be added to the rate for Basic Installation listed in 10.0 above.

9.1 Metal pole instead of wood pole, additional charge per unit per month $3.78. (New installations are available with underground service only).

9.2 Underground service extension, under sod, not in excess of 200 feet. Additional charge per unit per month $6.64.

9.3 Underground service extension under concrete, not in excess of 200 feet. Additional charge per unit per month $35.95.

9.4 Rock Removal or other specialized trenching/boring for installation of underground service. Additional charge per service per month $20.00.

9.5 Breakaway base. Additional charge per unit per month $3.48. (Available with underground service on metal poles only).

10.0 Special Mounting Heights: The standard mounting height is 31 ft. or less. The following rates for Special Mounting Heights may be added to the rate for new, basic installations listed in section 7.0.

		Wood Pole	Metal Pole
10.1	Between 31 and 41 ft.	$2.13	$3.38
10.2	Greater than 41 ft.	$4.49	$7.89

THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 73

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule ______ Sheet ______

Rate Areas 2 & 4
(Territory to which schedule is applicable)

which was filed

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 7 of 7 Sheets

MUNICIPAL STREET LIGHTING SERVICE
Schedule ML (Continued)

REPLACEMENT OF UNITS:

Existing street lamps shall be replaced at the same pole location with a different type of standard unit installation only by mutual agreement of the Company and the Municipality. The Company has the right to replace existing incandescent, mercury vapor, and high pressure sodium vapor street lamps in need of repair or replacement (or on poles in need of repair or replacement) with equivalent LED high pressure sodium vapor street lamps.

STANDARD UNITS:

Standard street lamps are those LED units for which a rate is stated except those with an X designation in the type code.

BURNING HOURS:

Unless otherwise stated, lamps are to burn each and every day of the year from one-half hour after sunset to one-half hour before sunrise, approximately 4100 hours per year.

ADJUSTMENTS AND SURCHARGES:

The rates hereunder are subject to adjustment as provided in the following schedules:

- Energy Cost Adjustment (ECA)
- Property Tax Surcharge (PTS)
- Tax Adjustment (TA)
- Transmission Delivery Charge (TDC)

REGULATIONS:

Subject to Rules and Regulations filed with the State Regulatory Commission.

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Month Day Year

Effective:
Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

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THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 74

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 74 Sheet 1

Rate Area 2 & 4
(Territory to which schedule is applicable)

which was filed June 21, 2017~~September 10, 2015~~

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 1 of 10 Sheets

MUNICIPAL TRAFFIC CONTROL SIGNAL SERVICE
Schedule TR

AVAILABILITY:

Available for traffic control signal service through a Company-owned Traffic Control System within corporate limits of a municipality.

TERM OF CONTRACT:

Contracts under this schedule shall be for a period of not less than ten years from the effective date thereof.

RATE: Basic Installations 2TSLM

1. ~~(1)~~ Individual Control. This basic installa ion consists of four mounted 3-light signal units all with 8-inch lenses, and is operated by its own controller (having no more than fourteen signal circuits), which is activated by a synchronous motor. The monthly rate for this basic installation is $~~165.13~~169.84. The monthly kWh is 213 kWh.

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Issued: May 1, 2018~~June 21, 2017~~
Month Day Year

Effective: ~~June 28, 2017~~
Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 74

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 74 Sheet 2

Rate Area 2 & 4
(Territory to which schedule is applicable)

which was filed June 21, 2017~~September 10, 2015~~

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Sheet 2 of 10 Sheets

MUNICIPAL TRAFFIC CONTROL SIGNAL SERVICE
Schedule TR (Continued)

RATE: Basic Installations 2TSLM (Continued)

2. ~~(3)~~ Flasher Control.

A. ~~(a)~~ 1-Way, 1-Light Signal Unit. This basic installation consists of one 1-light signal unit with an 8-inch lens mounted on an existing post, with the traffic signal lamp flashing alternately "on" and "off" 24 hours per day. The monthly rate for this basic installation is ~~38.98~~40.09. The monthly kWh is 50 kWh.

~~(b)~~B. 4-Way, 1-Light Signal Unit - Suspension. This basic installation consists of four 1-light signal units all with 8-inch lenses mounted by pipe fittings with the entire assembly suspended from an overhead messenger or from a mast arm with a minimum clearance distance of 15 feet above the roadway. The installation is operated by an individual flashing contactor which is activated by a synchronous motor. The monthly rate for this basic installation is ~~48.57~~49.95. The suspension system for this signal unit is provided for under Supplemental Equipment, Mast Arm, Wood Pole, Suspension or Steel Pole Suspension. The monthly kWh is 101 kWh.

3. ~~(4)~~ Pedestrian Push Button Control.

This basic installation consists of two 3-light signal units for vehicular control, two 2-light signal units for pedestrian control all with 8-inch lenses, a pair of push buttons for pedestrian actuation, a controller, and a flashing device. The monthly rate for this basic installation is ~~138.60~~142.55. The monthly kWh is 221 kWh.

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THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 74

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 74 Sheet 3

Rate Area 2 & 4
(Territory to which schedule is applicable)

which was filed June 21, 2017~~September 10, 2015~~

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Sheet 3 of 10 Sheets

MUNICIPAL TRAFFIC CONTROL SIGNAL SERVICE
Schedule TR (Continued)

RATE: Basic Installations 2TSLM (Continued)

4.~~(57)~~ Four-and Eight-Phase Electronic Control. This basic installation consists of a pad mounted four-phase or eight-phase electronic controller complete with cabinet, power supply and load relays; additional equipment as required, and all necessary interconnecting cables. This basic installation is available only to intersections where such basic installation is completed and operating after September 30, 1985. The monthly rate for this basic installation is as follows:

A. Four-phase electronic controller $~~496.78~~510.94

B. Eight-phase electronic controller $~~570.95~~587.23

C. Eight-phase electronic controller with pre-empt capabilities $~~676.17~~695.45

The monthly kWh is 55 kWh.

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THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 74

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 74 Sheet 4

Rate Area 2 & 4
(Territory to which schedule is applicable)

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Sheet 4 of 10 Sheets

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MUNICIPAL TRAFFIC CONTROL SIGNAL SERVICE
Schedule TR (Continued)

RATE: Supplemental Equipment 2TSLM

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5.~~(63)~~ 3-Light Signal Unit. This supplemental equipment consists of one 3-light signal unit with 8-inch lenses installed at any controlled intersection where the 3-light signal unit can be connected to the existing control cable and controller at such intersection. The monthly rate for this supplemental equipment is $~~23.74~~24.42. The monthly kWh is 50 kWh.

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This supplemental equipment can be used with the basic 4-Way 3-Light Suspension Control Signal Unit only if the signal units are hung on the same suspension system as the initial units.

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THE STATE CORPORATION COMMISSION OF KANSAS

KANSAS CITY POWER & LIGHT COMPANY

Rate Area 2 & 4
(Territory to which schedule is applicable)

SCHEDULE 74

Replacing Schedule 74 Sheet 5

which was filed June 21, 2017~~September 10, 2015~~

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Sheet 5 of 10 Sheets

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MUNICIPAL TRAFFIC CONTROL SIGNAL SERVICE
Schedule TR (Continued)

RATE: Supplemental Equipment 2TSLM (Continued)

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~~(C3) 3-Light Signal Unit. (continued)~~
~~This supplemental equipment can be used with the basic 4-Way 3-Light Suspension Control Signal Unit only if the signal units are hung on the same suspension system as the initial units.~~

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6.~~(74)~~ 2-Light Signal Unit. This supplemental equipment consists of one 2-light signal unit with 8-inch lenses installed at any controlled intersection where the 2-light signal unit can be connected to the existing control cable and controller at such intersection. The 2-light signal unit may have one lens worded "Walk" and the other lens worded "Wait", if specified by the customer. The monthly rate for this supplemental equipment is $~~22.83~~23.48. The monthly kWh is 50 kWh.

7.~~(85)~~ 1-Light Signal Unit. This supplemental equipment consists of one 1-light signal with an 8-inch lens installed as an addition to an existing signal unit at any controlled intersection where the 1-light signal unit can be connected to the existing control cable and controller at such intersection. The monthly rate for this supplemental equipment is $~~7.00~~7.20. The monthly kWh is 50 kWh.

~~(6)~~8. Push Buttons, Pair. This supplemental equipment consists of a pair of push buttons for pedestrian actuation which may be installed as pedestrian actuation devices at a basic Individual Control installation where Treadle Detectors or Loop Detectors are used or as additional stations at a basic Pedestrian Push Button Control installation and which can be connected to the existing control cable and controller at such installation and operated by the existing controller at such installation by the addition of necessary cams and relays. The monthly rate for this supplemental equipment is $~~3.17~~3.26.

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9.~~(107)~~ 12-Inch Round Lens. This supplemental equipment consists of a 12- inch diameter round lens and one 116-watt traffic signal type lamp which are substituted for an 8-inch lens and one 69-watt lamp. The monthly rate for this supplemental equipment is $~~5.52~~5.68. The monthly kWh is 48 kWh.

10. ~~(118)~~ 12-Inch Square Lens. This supplemental equipment consists of a 12-inch square lens and one 116-watt traffic signal type lamp which are substituted for an 8-inch lens and one 69-watt lamp. The monthly rate for this supplemental equipment is $~~8.84~~9.09. The monthly kWh is 66 kWh.

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Issued: May 1, 2018~~June 21, 2017~~
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Effective: ~~June 28, 2017~~
Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 74

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 74 Sheet 6

Rate Area 2 & 4
(Territory to which schedule is applicable)

which was filed June 21, 2017~~September 10, 2015~~

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Sheet 6 of 10 Sheets

MUNICIPAL TRAFFIC CONTROL SIGNAL SERVICE
Schedule TR (Continued)

RATE: Supplemental Equipment 2TSLM (Continued)

11. ~~(12)~~ 9-Inch Square Lens. This supplemental equipment consists of a 9-inch square lens and one 116-watt traffic signal type lamp which are substituted for an 8-inch lens and one 69-watt lamp. The monthly rate for this supplemental equipment is $~~6.19~~6.37. The monthly kWh is 50 kWh.

~~(13)~~ 12. Fiber Optic Arrow Lens. This supplemental equipment consists of an arrow-forming series of apertures powered by two 42-watt lamps which supply illumination to such apertures by means of optic fibers. The monthly rate for this supplemental equipment is $~~35.33~~36.34. The monthly kWh is 50 kWh.

~~(14)~~ 13. Directional Louvre. This supplemental equipment consists of one special 8-inch or 12-inch directional louvre visor which is substituted for one standard visor. The monthly rate for this supplemental equipment is $~~1.44~~1.48.

~~(15)~~ 14. Vehicle - Actuation Units.

A. ~~(b)~~ Loop Detector.

~~(i)~~a) Single. This supplemental equipment consists of one loop detector and one loop installed in the pavement so that vehicles passing over the loop operate the controller at the intersection. The monthly rate for this supplemental equipment is $~~29.20~~30.03. The monthly kWh is 15 kWh.

b)~~(ii)~~ Double. This supplemental equipment consists of one loop detector and two loops installed in the pavement so that vehicles passing over the loops operate the controller at the intersection. The monthly rate for this supplemental equipment is $~~46.29~~47.61. The monthly kWh is 18 kWh.

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THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 74

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 74 Sheet 7

Rate Area 2 & 4
(Territory to which schedule is applicable)

which was filed June 21, 2017~~September 10, 2015~~

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Sheet 7 of 10 Sheets

MUNICIPAL TRAFFIC CONTROL SIGNAL SERVICE
Schedule TR (Continued)

RATE: Supplemental Equipment 2TSLM (Continued)

~~(16)~~15. Flasher Equipment. This supplemental equipment consists of the necessary clock-controlled flasher equipment so that all signals at a controlled intersection may flash amber to traffic on the main street and flash red to traffic on the cross street during certain preset periods of time. The monthly rate for this supplemental equipment is $~~8.45~~8.69. The monthly kWh is 14 kWh.

~~(17)~~16. Mast Arm.

A. ~~(b)~~ Style 2. This supplemental equipment consists of a steel mast arm not to exceed 30 feet in length supported on a steel pole which may or may not also support a street lighting unit. The pole and mast arm shall be of a "classic" style with standard mast arm lengths of 15, 20, 25 or 30 feet, providing a minimum clearance for the traffic signal unit of 15 feet above the street. The monthly rate for this supplemental equipment, including pole, one mast arm, wiring cable, and traffic signal unit attachments, but excluding traffic signal unit, is $~~37.89~~38.97.

B. ~~(c)~~ Style 3. This supplemental equipment consists of a steel mast arm over 30 feet but not to exceed 38 feet in length, supported on a steel pole which may or may not also support a street lighting unit. The pole and mast arm shall be of a "classic" style with standard mast arm lengths of 35 and 38 feet, providing a minimum clearance for the traffic signal unit of 15 feet above the street. The monthly rate for this supplemental equipment, including pole, one mast arm, wiring cable and traffic signal unit attachments, but excluding traffic signal unit, is $~~38.18~~39.27.

C. Style 4. This supplemental equipment consists of a steel mast arm 40 feet or more in length, supported on a steel pole which may or may not also support a street lighting unit. The pole and mast arm shall be of a "classic" style. The mast arm shall provide a minimum clearance for the traffic signal unit of 15 feet above the street. The monthly rate for this supplemental equipment, including pole, one mast arm, wiring cable and traffic signal unit attachments, but excluding traffic signal unit, is $53.05.

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THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 74

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 74 Sheet 8

Rate Area 2 & 4
(Territory to which schedule is applicable)

which was filed June 21, 2017~~September 10, 2015~~

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Sheet 8 of 10 Sheets

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MUNICIPAL TRAFFIC CONTROL SIGNAL SERVICE
Schedule TR (Continued)

RATE: Supplemental Equipment 2TSLM (Continued)

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~~(184) Mast Arm (continued)~~

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~~(d) Style 4. This supplemental equipment consists of a steel mast arm 40 feet or more in length, supported on a steel pole which may or may not also support a street lighting unit. The pole and mast arm shall be of a "classic" style. The mast arm shall provide a minimum clearance for the traffic signal unit of 15 feet above the street. The monthly rate for this supplemental equipment, including pole, one mast arm, wiring cable and traffic signal unit attachments, but excluding traffic signal unit, is $51.5853.05.~~

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17. ~~(195)~~ Back Plate. This supplemental equipment consists of one back plate mounted behind a single head to extend ~~d~~ 8 inches beyond the signal in all directions. The monthly rate for this supplemental equipment is $~~1.71~~1.76.

18. ~~(2016)~~Wood Pole Suspension. This supplemental equipment consists of two wood poles, necessary guys and span cable to support suspension type traffic signal installations. The monthly rate for this supplemental equipment is $~~18.00~~18.51.

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19. ~~(2119)~~ Traffic Signal Pole. This supplemental equipment consists of a steel pole or an aluminum pole that is no more than 15 feet in length. The monthly rate for this supplemental equipment is $~~12.36~~12.71 for each pole.

Issued: May 1, 2018~~June 21, 2017~~ (Month Day Year)	
Effective: ~~June 28, 2017~~ (Month Day Year)	
By: /s/ Darrin R. Ives, Vice President (Title)	

THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 74

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 74 Sheet 9

Rate Area 2 & 4
(Territory to which schedule is applicable)

which was filed June 21, 2017~~September 10, 2015~~

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 9 of 10 Sheets

MUNICIPAL TRAFFIC CONTROL SIGNAL SERVICE
Schedule TR (Continued)

RATE: Supplemental Equipment 2TSLM (Continued)

20.~~(220)~~ Preemption Control for Emergency Equipment. This supplemental equipment consists of an activation switch, interconnecting cable, and an interface with the traffic signal controller that allows emergency vehicles to preempt the normal signal sequence. The activation switch is located in a fire station or other emergency facility. The monthly rate for this supplemental equipment is $~~53.84~~55.37. Availability of this rate is subject to the discretion of the Company.

~~(~~21.~~81)~~ Optically Activated Traffic Signal Priority Control System. This supplemental equipment consists of one D harness and preempt panel, one phase selector, required optical detectors, one interface card rack, optical detector cable of up to 1000 feet in length, mounting brackets, and system control software. This equipment provides optically activated priority control over the traffic signals in one intersection. The monthly rate for this system is $~~158.74~~163.27 for each intersection. The system is activated remotely with a data encoded emitter that is installed on emergency vehicles. Customers are responsible for the purchase and installation of all data encoded emitters used on the customers' emergency vehicles, so the cost of such emitters is not included in the above monthly rate. Additionally, the cost of any upgrades of existing equipment necessitated by installation of this system is not included in the rate. The monthly kWh is 20 kWh.

~~(24)~~22. Audio Warning Systems for the Visually Impaired. For each intersection including the described supplemental equipment, the customer will be billed one of the following rates:

Rate A: For a Standard Intersection consisting of 4 street corners with crossings in 2 directions from each corner:

A. ~~directions from each corner:~~

8 Navigator pedestrian push button stations using 2-wire technology, with 5" x 7" international walking signs, with Braille inscriptions on the push button units.

~~international walking signs, with Braille inscriptions on the push button units.~~

a)

b) 1 Central control unit mounted in the cabinet.

The monthly rate for this system is $~~346.67~~356.55 per intersection. The monthly kWh is 87 kWh.~~kWh.~~

B. Rate B: For Non-Standard Intersections:

The monthly rate is $~~164.56~~169.25 for the central control unit plus $~~22.77~~23.42 per each required station using 2-wire technology, 5" x 7" signs and Braille inscriptions. The monthly kWh is 29 kWh for the central control unit and 7 kWh for each station.

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Month Day Year

Effective: ~~June 28, 2017~~
Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

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THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 74

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 74 Sheet 10

Rate Area 2 & 4
(Territory to which schedule is applicable)

which was filed June 21, 2017~~September 10, 2015~~

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 10 of 10 Sheets

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MUNICIPAL TRAFFIC CONTROL SIGNAL SERVICE
Schedule TR (Continued)

RATE: Supplemental Equipment 2TSLM (Continued)

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23. ~~(253)~~ Camera Video Detection System. For each standard intersection including the described supplemental equipment, the customer will be billed the shown rate:

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For a Standard Intersection consisting of 4 directional traffic flows:

A. 4 Image sensors (cameras) with luminaire arm mounting bracket.
B. 4 Image sensor harnesses.
C. 1 Interface panel.
D. 1 Detector port master with harness.
E. Plus required cable and software package.

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The monthly rate for this system is $~~1,069.77~~1,100.27 per intersection. The monthly kWh is 26 kWh.

Additionally, the costs of any upgrades of existing equipment necessitated by installation of a system must be paid.

The monthly rates for each type of Supplemental Equipment at an intersection are in addition to the monthly rate for the Basic Installation at that intersection.

ADJUSTMENTS AND SURCHARGES:

The rates hereunder are subject to adjustment as provided in the following schedules:

- Energy Cost Adjustment (ECA)
- Property Tax Surcharge (PTS)
- Tax Adjustment (TA)
- Transmission Delivery Charge (TDC)

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REGULATIONS:

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Subject to Rules and Regulations filed with the State Regulatory Commission.

Issued: May 1, 2018~~June 21, 2017~~
Month Day Year

Effective: ~~June 28, 2017~~
Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 77

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 77 Sheet 1

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Rate Areas No 2 & 4
(Territory to which schedule is applicable)

which was filed September 10, 2015~~November 12, 1998~~

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No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 1 of 1 Sheets

THERMAL STORAGE RIDER
Schedule TS

AVAILABILITY:

This Rider shall be available to all customers with installations of Thermal Storage Systems of a size and design approved by the Company who are currently receiving or have requested service under any of the following rate schedules: SGS, MGS, LGS, SGA, MGA, or LGA~~, RTP, or RTP Plus~~.

DETERMINATION OF DEMAND:

For customers with Thermal Storage Systems the Monthly Maximum Demand for any month included in the summer season, shall be the highest demand indicated in any 30-minute interval in that month during the period noon to 8 p.m., Monday through Friday (except holidays). Week-day holidays are Memorial Day, Independence Day and Labor Day. All other terms and conditions of the Customer's service schedule shall continue.

METERING:

The Company has the right to submeter the demand and usage of the thermal storage system.

TERMINATION:

Termination of service under this rider shall occur if the customer discontinues operation of the Thermal Storage System.

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Month Day Year

Effective: ~~October 1, 2015~~
Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 79

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 79 Sheet 1

Rate Areas No 2 & 4
(Territory to which schedule is applicable)

which was filed September 10, 2015~~February 16, 2000~~

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 1 of 5 Sheets

Real-Time Pricing (FROZEN)
Schedule RTP

CANCELLED

~~PURPOSE:~~

~~The Real-Time Pricing (RTP) program provides electricity prices that are time-differentiated based on the Company's marginal cost of electricity. RTP offers industrial and commercial Customers the opportunity to grow or reduce load at marginal cost-based prices, and to shift load from higher-cost to lower-cost hours. Binding quotes for hourly energy prices are sent to each Customer on a day-ahead basis.~~

~~AVAILABILITY:~~

~~Electric Service is available under this schedule at points on the Company's existing distribution facilities located within its service area. This schedule is available to Customers who elect to execute a written contract to participate in the Real-Time Pricing (RTP) program. Customers seeking service under this schedule must have a maximum demand of at least 500 kW as defined in the section entitled "Customer Baseline Load." The Company reserves the right to determine the applicability or the availability of this price schedule to any specific applicant for electric service who meets the above criteria.~~

~~This price schedule is not available for resale, standby, breakdown, auxiliary or supplemental service. Customers currently served on the Demand Response Incentive Rider (Schedule DR) are eligible to be served under this schedule, as discussed in the section entitled "Special Provisions for Demand Response Incentive Rider Customers."~~

~~This schedule is not available after October 1, 2015.~~

~~SPECIAL PROVISIONS:~~

~~A. Price Notification, Pricing Periods and Responsibility:~~

~~Each day by 4:00 p.m., the Company will make available to Customers twenty-four hourly prices for the following day, via a method specified by the Company. Each hour is a distinct pricing period and the corresponding quoted energy price is applicable to all energy consumption during that hour. Daily pricing periods begin with the hour ending 0100 and end with the hour ending 2400.~~

~~Except during unusual times of potential emergency or peak conditions, the Company will make prices for Saturday through Monday available on the previous Friday. More than day-ahead pricing may also be used for holidays as defined in the Company's conventional price schedules or accepted traditional holidays. Under potential emergency or peak conditions, the Company may not be able to accurately project prices more than one day in advance and reserves the right to update prices on a one-day-ahead basis, even if those prices are updated on weekends or holidays. The Company is not responsible for a Customer's failure to receive and act upon the hourly RTP prices. If a Customer does not receive these prices, it is the Customer's responsibility to inform the Company so the prices may be supplied.~~

Issued: May 1, 2018~~September 10, 2015~~
Month Day Year

Effective: ~~October 1, 2015~~
Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

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Real-Time Pricing (FROZEN)
Schedule RTP (continued)

CANCELLED

~~**SPECIAL PROVISIONS: (continued)**~~

~~B. Pricing Methodology:~~
~~Hourly prices are determined each day based on projections of the hourly running cost of incremental generation and hourly wholesale prices, provisions for line losses, and projections of hourly outage costs (when applicable). Each hour, an additional variable amount will be included in the hourly price which will contribute to incremental overhead, if any, as well as risk recovery and contribution to margin.~~

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~~C. Metering of Load:~~
~~Standard metering for RTP is the conventional hourly demand recording meter.~~

~~D. Additional Costs:~~
~~Customers will be responsible to the Company for any additional cost associated with providing service on this tariff. The Company requires the use of a telephone line or other communication link deemed acceptable by the Company for meter reading and price transmission.~~

~~**TERM OF CONTRACT AND TERMINATION:**~~

~~The Customer is required to sign a contract for the duration of the program. A Customer may cancel participation under the RTP price schedule and return to a standard price schedule upon thirty (30) days written notice of the intent to cancel. A Customer may return to the standard price schedule without penalty, and with the same billing determinants, including elapsed time as related to the determination of demands for billing, that existed prior to taking service under RTP. Usage under RTP will not affect a Customer's billing determinants under the standard price schedule. At the Company's discretion, a Customer may be able to switch from service under Schedule RTP to service under Schedule RTP Plus, or switch back to Schedule RTP from Schedule RTP Plus.~~

~~**CUSTOMER BASELINE LOAD (CBL):**~~

~~The Customer Baseline Load (CBL) is one complete year of Customer specific hourly load data that represent the normal electricity consumption pattern and level typical of the Customer's operations under the applicable standard (non RTP) price schedule. In order to formulate a CBL that achieves this representative load pattern, the Company may make adjustments to historical usage data or may estimate usage if historical data are not available or are not appropriate. Such adjustments will include facility expansions, facility reductions, and/or energy efficient equipment installations completed prior to commencement of service under this schedule. For Demand Response Incentive Rider (Schedule DR) Customers, the Company will add back usage to the Customer's CBL for periods of load reduction when the Customer complied with a curtailment request. The Company will "fill in" the load reduction with usage levels comparable to other hours.~~

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THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 79

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 79 Sheet 3

Rate Areas No 2 & 4
(Territory to which schedule is applicable)

which was filed September 10, 2015~~February 16, 2000~~

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 3 of 5 Sheets

Real-Time Pricing (FROZEN)
Schedule RTP (C~~c~~ontinued)

CANCELLED

~~**CUSTOMER BASELINE LOAD (CBL):**~~

~~The CBL is the basis for achieving revenue neutrality on a Customer specific basis for Customers using the RTP price schedule, and must be mutually agreed upon by both the Customer and the Company. Agreement on the CBL is a precondition for participation in the RTP program. The CBL will not generally change during the term of the RTP program.~~

~~If the Company is required to either increase the capacity or accelerate its plans for increasing the capacity of the transmission or distribution facilities to accommodate a Customer's increased load, then an additional facilities charge will be assessed if the expansion is not revenue justified using KCPL's current methodology.~~

~~**BILL DETERMINATION:**~~

~~An RTP bill is rendered after each monthly billing period and is calculated using the following formula:~~

~~RTP Bill~~ $_{mo}$ ~~= Standard Bill~~ $_{mo}$ ~~+ Σ Price~~ $_{hr}$ ~~x [Actual Load~~ $_{hr}$ ~~- CBL~~ $_{hr}$ ~~] + PC~~

~~Where:~~

~~RTP Bill~~ $_{mo}$ ~~= Customer's bill for service under this price schedule for the billing month;~~

~~Standard Bill~~ $_{mo}$ ~~= Customer's baseline load for the billing month, billed under the applicable (non-RTP) price schedule;~~

~~Actual Load~~ $_{hr}$ ~~= The Customer's actual energy usage for the hour;~~

~~CBL~~ $_{hr}$ ~~= The Customer's baseline energy usage on a hourly basis, as defined above;~~

~~PC = Program Charge (BAC + CC + CSCC);~~

~~BAC = Billing and Administrative Charge;~~

~~CC = Communications Charge (if applicable);~~

~~CSCC = Company Supplied Computer Charge (if applicable);~~

~~Σ = Sum over all hours of the billing month;~~

Issued: May 1, 2018~~September 10, 2015~~ (Month Day Year)	
Effective: ~~October 1, 2015~~ (Month Day Year)	
By: /s/ Darrin R. Ives, Vice President (Title)	

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THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 79

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)
Rate Areas No 2 & 4
(Territory to which schedule is applicable)

Replacing Schedule 79 Sheet 4

which was filed September 10, 2015~~March 15, 2003~~

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 4 of 5 Sheets

Real-Time Pricing (FROZEN)
Schedule RTP (C~~c~~ontinued)

CANCELLED

~~**BILL DETERMINATION: (continued)**~~

~~$Price_{hr}$ = MC_{hr} + .25 times (EEC_{hr} - MC_{hr}) ;~~

~~Where:~~

~~MC_{hr} = Projections of the hourly running costs of incremental generation and hourly wholesale prices, provisions for line losses, and hourly outage costs (when applicable);~~

~~EEC_{hr} = The effective energy charge on an hourly basis calculated from the applicable standard (non RTP) price schedule. The hourly standard charge is termed "effective" because it is derived from the standard schedule and the changes in standard Customers' bills when they change usage. The EEC_{hr} includes the effects of all demand, energy, and Customer charges in that schedule.~~

~~**SPECIAL PROVISIONS FOR DEMAND RESPONSE INCENTIVE RIDER CUSTOMERS:**~~

~~Customers taking service under the Company's Demand Response Incentive Rider (Schedule DR) will have the option to switch to RTP or RTP Plus service. Customers choosing either Option 1 or Option 2 will not be allowed to return to the DR Rider until one year has elapsed since the election of the DR/RTP Option. Customers electing to return to the DR Rider will be subject to the same terms and conditions of service as their previous DR agreement. A Customer may switch back to RTP or RTP Plus service after one year has elapsed since returning to the DR Rider. Customers may choose from the following two options:~~

~~DR/RTP OPTION 1: Customers choosing Option 1 will no longer receive DR credits on their Standard Bill and will no longer be required to reduce load during times of Company peak load conditions.~~

~~DR/RTP OPTION 2: Customers choosing Option 2 will receive credits based on their current curtailable load under the DR. The curtailment credit shall be equal to one-half of the then applicable DR Rider credit per kW of curtailable load. During times of Company peak load conditions when the DR Customers are notified of impending curtailments, the Option 2 Customers' CBL's will be reduced to their former contractual Firm Power Level for the entire period of the DR curtailment. If the customer's CBL in any hour is below the customer's Firm Power Level, the CBL will not be modified in that hour. The Company reserves the right to update the hourly outage cost component of the RTP energy prices within one hour of notifying the Option 2 Customers of the impending CBL reduction. KWh usage differing from the Option 2 Customer's reduced CBL will be priced at the hourly energy price for RTP.~~

Issued: May 1, 2018~~September 10, 2015~~
Month Day Year

Effective: ~~October 1, 2015~~
Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

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THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 79

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 79 Sheet 5

Rate Areas No 2 & 4
(Territory to which schedule is applicable)

which was filed September 10, 2015~~February 16, 2000~~

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 5 of 5 Sheets

Real-Time Pricing (FROZEN)
Schedule RTP (~~C~~continued)

CANCELLED

~~**BILLING AND ADMINISTRATIVE CHARGE:**~~

~~A billing and administrative charge of $45 per month is required to cover costs associated with the program.~~

~~**COMMUNICATIONS CHARGE:**~~

~~A communications charge of $115 per month is required to cover costs associated with the program. This charge will be waived if the Customer supplies Company approved communications software. In addition, the Customer will provide access for the phone connection and will be responsible for supplying the phone line between the personal computer and the Company's metering equipment.~~

~~**COMPANY SUPPLIED COMPUTER CHARGE:**~~

~~At the Customer's option, a KCPL standard notebook personal computer with a modem for receiving RTP prices using pre loaded communications software, can be supplied by the Company. The Customer will pay the cost of the Company supplied computer, which will be calculated based on the current monthly cost of a Company standard computer. The Company supplied computer may be used for other applications, as the Customer desires. However, the Customer will be responsible for any damages to the computer hardware or communications software resulting from such action.~~

~~Alternatively, the Customer may supply the computer, which must have minimum performance specifications as required by KCPL. In this case, there will be no computer charge.~~

~~**REACTIVE DEMAND ADJUSTMENT:**~~

~~Reactive demand associated both with the CBL and with incremental RTP load will be billed in accordance with the Customer's otherwise applicable, standard (non RTP) rate schedule. The Customer's Standard Bill does not include any reactive demand charges paid by the Customer for the historical usage period.~~

~~**TAX ADJUSTMENT:**~~

~~Tax Adjustment Schedule TA shall be applicable to all Customer billings under this schedule.~~

~~**REGULATION:**~~

~~Subject to Rules and Regulations filed with the Kansas Corporation Commission.~~

Issued: May 1, 2018~~September 10, 2015~~
Month Day Year

Effective: ~~October 1, 2015~~
Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

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THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 80

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 80 Sheet 1

Rate Areas No 2 & 4
(Territory to which schedule is applicable)

which was filed September 10, 2015~~February 16, 2000~~

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 1 of 5 Sheets

Real-Time Pricing (FROZEN)
Schedule RTP-Plus

CANCELLED

~~**PURPOSE:**~~

~~The Real Time Pricing (RTP Plus) program provides electricity prices that are time differentiated based on the Company's marginal cost of electricity. RTP Plus offers industrial and commercial Customers the opportunity to grow or reduce load at marginal cost based prices, and to shift load from higher cost to lower cost hours. Binding quotes for hourly energy prices are sent to each Customer on a day ahead basis.~~

~~**AVAILABILITY:**~~

~~Electric Service is available under this schedule at points on the Company's existing distribution facilities located within its service area. This schedule is available to Customers who elect to execute a written contract to participate in the Real Time Pricing (RTP) program. Customers seeking service under this schedule must have a maximum demand of at least 500 kW as defined in the section entitled "Customer Baseline Load." The Company reserves the right to determine the applicability or the availability of this price schedule to any specific applicant for electric service who meets the above criteria.~~

~~This price schedule is not available for resale, standby, breakdown, auxiliary or supplemental service. Customers currently served on the Demand Response Incentive Rider (Schedule DR) are eligible to be served under this schedule, as discussed in the section entitled "Special Provisions for Demand Response Incentive Rider Customers."~~

~~This schedule is not available after October 1, 2015.~~

~~**SPECIAL PROVISIONS:**~~

~~A. Price Notification, Pricing Periods and Responsibility:~~

~~Each day by 4:00 p.m., the Company will make available to Customers twenty four hourly prices for the following day, via a method specified by the Company. Each hour is a distinct pricing period and the corresponding quoted energy price is applicable to all energy consumption during that hour. Daily pricing periods begin with the hour ending 0100 and end with the hour ending 2400.~~

~~Except during unusual times of potential emergency or peak conditions, the Company will make prices for Saturday through Monday available on the previous Friday. More than day ahead pricing may also be used for holidays as defined in the Company's conventional price schedules or accepted traditional holidays. Under potential emergency or peak conditions, the Company may not be able to accurately project prices more than one day in advance and reserves the right to update prices on a one day ahead basis, even if those prices are updated on weekends or holidays. The Company is not responsible for a Customer's failure to receive and act upon the hourly RTP Plus prices. If a Customer does not receive these prices, it is the Customer's responsibility to inform the Company so the prices may be supplied.~~

Issued: May 1, 2018~~September 10, 2015~~
Month Day Year

Effective: ~~October 1, 2015~~
Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

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THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 80

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 80 Sheet 2

Rate Areas No 2 & 4
(Territory to which schedule is applicable)

which was filed September 10, 2015~~February 16, 2000~~

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 2 of 5 Sheets

Real-Time Pricing (FROZEN)
Schedule RTP-Plus (continued)

CANCELLED

~~**SPECIAL PROVISIONS: (continued)**~~

~~B. Pricing Methodology:~~

~~Hourly prices are determined each day based on projections of the hourly running cost of incremental generation and hourly wholesale prices, provisions for line losses, and projections of hourly outage costs (when applicable). Each hour, an additional variable amount will be included in the hourly price which will contribute to incremental overhead, if any, as well as risk recovery and contribution to margin.~~

~~C. Metering of Load:~~
~~Standard metering for RTP Plus is the conventional hourly demand recording meter.~~

~~D. Additional Costs:~~
~~Customers will be responsible for any additional cost associated with providing service on this tariff. The Company requires the use of a telephone line or other communication link deemed acceptable by the Company for meter reading and price transmission.~~

~~**TERM OF CONTRACT AND TERMINATION:**~~

~~The Customer is required to sign a contract for the duration of the program. A Customer may cancel participation under the RTP Plus schedule and return to a standard price schedule upon thirty (30) days written notice of the intent to cancel. A Customer may return to the standard price schedule without penalty and with the same billing determinants, including elapsed time as related to the determination of demands for billing, that existed prior to taking service under RTP Plus. Usage under RTP Plus will not affect a Customer's billing determinants under the standard price schedule. At the Company's discretion, a Customer may be able to switch from service under Schedule RTP Plus to service under Schedule RTP, or switch back to Schedule RTP Plus from Schedule RTP.~~

~~**CUSTOMER BASELINE LOAD (CBL):**~~

~~The Customer Baseline Load (CBL) is one complete year of Customer specific hourly load data that represent the normal electricity consumption pattern and level typical of the Customer's operations under the applicable standard (non-RTP) price schedule. In order to formulate a CBL that achieves this representative load pattern, the Company may make adjustments to historical usage data or may estimate usage if historical data are not available or are not appropriate. Such adjustments will include facility expansions, facility reductions, and/or energy efficient equipment installations completed prior to commencement of service under this schedule. For Demand Response Incentive Rider (Schedule DR) Customers, the Company will add back usage to the Customer's CBL for periods of load reduction when the Customer complied with a curtailment request. The Company will "fill in" the load reduction with usage levels comparable to other hours.~~

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THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 80

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 80 Sheet 3

Rate Areas No 2 & 4
(Territory to which schedule is applicable)

which was filed September 10, 2015~~February 16, 2000~~

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 3 of 5 Sheets

Real-Time Pricing (FROZEN)
Schedule RTP-Plus (C~~c~~ontinued)

CANCELLED

~~**CUSTOMER BASELINE LOAD (CBL):**~~

~~The CBL is the basis for achieving revenue neutrality on a Customer specific basis for Customers using the RTP Plus price schedule, and must be mutually agreed upon by both the Customer and the Company. Agreement on the CBL is a precondition for participation in the RTP Plus program. The CBL will not generally change during the term of the RTP Plus program.~~

~~If the Company is required to either increase the capacity or accelerate its plans for increasing the capacity of the transmission or distribution facilities to accommodate a Customer's increased load, then an additional facilities charge will be assessed if the expansion is not revenue justified using KCPL's current methodology.~~

~~**BILL DETERMINATION:**~~

~~An RTP Plus bill is rendered after each monthly billing period and is calculated using the following formula:~~

$$\cancel{\text{RTP Plus Bill}_{mo} = \text{Standard Bill}_{mo} + (.05 * (\text{Standard Bill}_{mo} - \Sigma\text{Price}_{hr} * \text{CBL}_{hr})) + \Sigma\,\text{Price}_{hr} \times [\text{Actual Load}_{hr} - \text{CBL}_{hr}] + \text{PC}}$$

~~Where:~~

~~RTP Plus Bill~~ $\cancel{_{mo}}$ ~~= Customer's bill for service under this price schedule for the billing month;~~

~~Standard Bill~~ $\cancel{_{mo}}$ ~~= Customer's baseline load for the billing month, billed under the applicable (non RTP Plus) price schedule;~~

~~Actual Load~~ $\cancel{_{hr}}$ ~~= The Customer's actual energy usage for the hour;~~

~~CBL~~ $\cancel{_{hr}}$ ~~= The Customer's baseline energy usage on a hourly basis, as defined above;~~

~~PC = Program Charge (BAC + CC + CSCC);~~

~~BAC Billing and Administrative Charge;~~

~~CC = Communications Charge (if applicable);~~

~~CSCC = Company Supplied Computer Charge (if applicable);~~

~~Σ = Sum over all hours of the billing month;~~

Issued: May 1, 2018~~September 10, 2015~~
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Real-Time Pricing (FROZEN)
Schedule RTP-Plus (C~~c~~ontinued)

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~~**BILL DETERMINATION: (continued)**~~

~~$Price_{hr}$ = MC_{hr} + .05 times (EEC_{hr} - MC_{hr});~~

~~Where:~~

~~Mc_{hr} - Projections of the hourly running costs of incremental generation and hourly wholesale prices, provisions for line losses, and hourly outage costs (when applicable);~~

~~EEC_{hr} = The effective energy charge on an hourly basis calculated from the applicable standard (non RTP) price schedule. The hourly standard charge is termed "effective" because it is derived from the standard schedule and the changes in standard Customers' bills when they change usage. The EEC_{hr} includes the effects of all demand, energy, and customer charges in that schedule.~~

~~**SPECIAL PROVISIONS FOR DEMAND RESPONSE INCENTIVE RIDER CUSTOMERS:**~~

~~Customers taking service under the Company's Demand Response Incentive (Schedule DR) Rider will have the option to switch to RTP or RTP Plus service. Customers choosing either Option 1 or Option 2 will not be allowed to return to the DR Rider until one year has elapsed since the election of the DR/RTP Option. Customers electing to return to the DR Rider will be subject to the same terms and conditions of service as their previous DR agreement. A Customer may switch back to RTP or RTP Plus service after one year has elapsed since returning to the DR Rider. Customers may choose from the following two options:~~

~~DR/RTP Plus OPTION 1: Customers choosing Option 1 will no longer receive DR credits on their Standard Bill and will no longer be required to reduce load during times of Company peak load conditions.~~

~~DR/RTP Plus OPTION 2: Customers choosing Option 2 will receive credits based on their current curtailable load under the DR. The curtailment credit shall be equal to one-half of the then applicable DR Rider credit per kW of curtailable load. During times of Company peak load conditions when the DR Customers are notified of impending curtailments, the Option 2 Customers' CBL's will be reduced to their former contractual Firm Power Level for the entire period of the DR curtailment. If the customer's CBL in any hour is below the customer's Firm Power Level, the CBL will not be modified in that hour. The Company reserves the right to update the hourly outage cost component of the RTP Plus energy prices within one hour of notifying the Option 2 Customers of the impending CBL reduction. KWh usage differing from the Option 2 Customer's reduced CBL will be priced at the hourly energy price for RTP Plus.~~

THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 80

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 80 Sheet 5

Rate Areas No 2 & 4
(Territory to which schedule is applicable)

which was filed September 10, 2015~~February 16, 2000~~

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 5 of 5 Sheets

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Real-Time Pricing (FROZEN)
Schedule RTP-Plus ~~-~~(~~C~~continued)

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~~**BILLING AND ADMINISTRATIVE CHARGE:**~~

~~A billing and administrative charge of $45 per month is required to cover costs associated with the program.~~

~~**COMMUNICATIONS CHARGE:**~~

~~A communications charge of $115 per month is required to cover costs associated with the program. This charge will be waived if the Customer supplies Company approved communications software. In addition, the Customer will provide access for the phone connection and will be responsible for supplying the phone line between the personal computer and the Company's metering equipment.~~

~~**COMPANY SUPPLIED COMPUTER CHARGE:**~~

~~At the Customer's option, a KCPL standard notebook personal computer with a modem for receiving RTP prices using pre-loaded communications software, can be supplied by the Company. The Customer will pay the cost of the Company supplied computer, which will be calculated based on the current monthly cost of a Company standard computer. The Company supplied computer may be used for other applications, as the Customer desires. However, the Customer will be responsible for any damages to the computer hardware or communications software resulting from such action.~~

~~Alternatively, the Customer may supply the computer, which must have minimum performance specifications as required by KCPL. In this case, there will be no computer charge.~~

~~**REACTIVE DEMAND ADJUSTMENT:**~~

~~Reactive demand associated both with the CBL and with incremental RTP Plus load will be billed in accordance with the Customer's otherwise applicable, standard (non RTP Plus) rate schedule. The Customer's Standard Bill does not include any reactive demand charges paid by the Customer for the historical usage period.~~

~~**TAX ADJUSTMENT:**~~

~~Tax Adjustment Schedule TA shall be applicable to all Customer billings under this schedule.~~

~~**REGULATIONS:**~~

~~Subject to Rules and Regulations filed with the State Regulatory Commission.~~

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Issued: May 1, 2018~~September 10, 2015~~
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Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

THE STATE CORPORATION COMMISSION OF KANSAS

SCHEDULE 82

KANSAS CITY POWER & LIGHT COMPANY
(Name of Issuing Utility)

Replacing Schedule 82 Sheet 2

Rate Areas No 2 & 4
(Territory to which schedule is applicable)

which was filed June 21, 2017~~September 10, 2015~~

No supplement or separate understanding shall modify the tariff as shown hereon

Sheet 2 of 3 Sheets

MUNICIPAL STREET LIGHTING SERVICE
LIGHT EMITTING DIODE PILOT PROGRAM
Schedule ML-LED

RATE (LED): 2MLLL

The rates charged for 10.1 and 10.2 below are exclusively for the purposes of the Pilot Project and are not reflective of rates that may be associated with a LED lighting schedule upon completion of pilot period study. An LED lighting rate may be developed based on the outcome of this pilot and or other relevant information.

10.0 Basic Installation:
Street lamps equipped with hood, reflector, and refractor, on wood poles serviced from overhead circuits by an extension not in excess of 200 feet per unit: (Code OW)

	Size of Lamp	Monthly kWh	Lumen Charge per Lamp per Year(1)	Total Charge per Lamp per Year(1)
10.1	Small LED (≤ 7000 lumens)	21	~~$22.80~~ 23.40	~~$186.16~~190.44
10.2	Large LED (> 7000 lumens)	44	~~$49.32~~50.76	~~$211.68~~217.68

(1)Rates above are based on a Base Unit Charge of ~~$162.36~~167.04 plus a Lumen Charge as stated above. Twin units will be billed at one and one-half (1 1/2) times the Base Unit Charge plus (2) times the appropriate Lumen Charge. KWh usage for twin lamps is two times the single monthly kWh.

11.0 Optional Equipment: The following rates for Optional Equipment shall be added to the rate for Basic Installation listed in 10.1 and 10.2 above for LED installations only.

11.1 Ornamental steel pole instead of wood pole, additional charge per unit per year ~~$45.36~~46.68. (New installations are available with underground service only).

11.2 Aluminum pole instead of a wood pole, additional charge per unit per year ~~$93.12~~95.76. (Available with underground service only).

11.3 Underground service extension, under sod, not in excess of 200 feet. Additional charge per unit per year ~~$79.68~~81.96.

11.4 Underground service extension under concrete, not in excess of 200 feet. Additional charge per unit per year ~~$431.64~~444.00.

11.5 Breakaway base. Additional charge per unit per year ~~$41.76~~42.96. (Available with underground service only).

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GENERAL RULES AND REGULATIONS APPLYING TO ELECTRIC SERVICE (~~c~~Continued)

1. DEFINITIONS (~~c~~Continued)

1.10 CUSTOMER'S INSTALLATION:

All wiring, appliances and apparatuses of every kind and nature on the Customer's premises, on the Customer's side of the point of delivery (except the Company's meter installation), used or useful by the Customer in connection with the receipt and utilization of electric service supplied by the Company.

1.11 POINT OF DELIVERY:

The point at which the Company's conductors and/or equipment (other than the Company's meter installation) make electrical connection with the Customer's installation, unless otherwise specified in the Customer's service agreement. Examples of typical meter configurations depicting the point of delivery can be found in the Company's Construction Standards at www.kcpl.com.

1.12 METER INSTALLATION:

The meter or meters, together with auxiliary devices, if any, constituting the complete installation needed by the Company to measure the class of electric service supplied to a Customer at a single point of delivery.

1.13 MONTH:

An interval of approximately thirty (30) days, unless specified or appearing from the context to be a calendar month.

1.14 SERVICE AGREEMENT:

The application, agreement or contract, expressed or implied, pursuant to which the Company supplies electric service to the Customer.

1.15 ADULT:

One who has reached the legal age of majority, generally 18 years.

1.16 BILLING ERROR:

The incorrect billing of an account due to a Company or Customer meter reading error, which results in incorrect charges.

1.17 FIELD ERROR:

Shall be considered to include lost/mishandled paperwork, installing metering incorrectly, or failure to close the meter potential or test switches. A Field Error may result in a Billing Error.

GENERAL RULES AND REGULATIONS
APPLYING TO ELECTRIC SERVICE (continued)

APPENDIX A (continued)
AGREEMENTS (continued)

(3) PRIVATE, UNMETERED, PROTECTIVE LIGHTING SERVICE INSTALLATION

The Company may enter into agreements with customers or prospective customers as needed to complete requests for service. These requests will take various forms depending on the type of service requested. All agreements will be consistent with terms and conditions of Kansas law and the Company's Commission approved tariffs and regulations.

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APPLICATION FOR PRIVATE AREA LIGHTING SERVICE

Customer Name	Account #	Phone #	Date of Prior Agreement
Service Address	Service City, State, Zip		Service County
Billing Address	Billing City, State, Zip		Work Request #
**Service Area:	Service Type: ☐ Residential ☐ Commercial (includes apts)		Action: ☐ Install ☐ Remove

	Equipment Description	Rate/MRU CODE	Unit Cost/Mo.^	Existing Units #	Existing Units $	Units to Be Installed #	Units to Be Installed $	Units to Be Removed #	Units to Be Removed $	Units Covered by Agreement #	Units Covered by Agreement $
Sodium	70 Watt Area				$0.00		$0.00		$0.00	0	$0.00
	150 Watt Flood				$0.00		$0.00		$0.00	0	$0.00
	400 Watt Flood				$0.00		$0.00		$0.00	0	$0.00
Poles	30 Ft. Wood				$0.00		$0.00		$0.00	0	$0.00
	35 Ft. Wood				$0.00		$0.00		$0.00	0	$0.00
	30 Ft. Steel				$0.00		$0.00		$0.00	0	$0.00
	35 Ft. Steel				$0.00		$0.00		$0.00	0	$0.00
Additional Spans	Overhead				$0.00		$0.00		$0.00	0	$0.00
	Underground (max 300 ft. ea)				$0.00		$0.00		$0.00	0	$0.00
Other					$0.00		$0.00		$0.00	0	$0.00
					$0.00		$0.00		$0.00	0	$0.00
					$0.00		$0.00		$0.00	0	$0.00
					$0.00		$0.00		$0.00	0	$0.00
					$0.00		$0.00		$0.00	0	$0.00
Total Base Cost Per Month^				0	$0.00	0	$0.00	0	$0.00	0	$0.00
Special Billing Instructions											

^Total base cost per month is approximate and is subject to various riders and adjustments specified in the applicable rate schedule and to any rate revision subsequently approved by the state regulatory commission. Final base cost shall be determined by the applicable rate schedule in effect at the time of billing.

**For the purposes of this Customer Agreement, "The Company" shall refer to the company as noted in the box above titled "Service Area."

CUSTOMER AGREEMENT

- I the customer, hereby apply to The Company for the private, unmetered protective lighting service designated herein and agree to pay The Company for service received in accordance with The Company's applicable Rate Schedule and Rules and Regulations on file and in effect pursuant to state regulatory commission law during the period such service is furnished.
- I (if owner of premises) hereby grant to The Company the right to enter, locate, erect, install, operate, maintain, replace and remove the Company's facilities required for such service ("Entry and Exit Rights"). If I am not the owner, I will obtain from the owner written Entry and Exit Rights and provide it to The Company prior to installation of The Company's facilities. In addition, upon request from The Company I will sign any necessary documents needed to grant The Company an easement or easements with Entry and Exit Rights. If I am not the owner, I will obtain from the owner signed documents needed to grant to The Company an easement or easements with Entry and Exit Rights.
- After the initial term agreed to below, this agreement shall continue in effect from month to month unless terminated by mutual agreement of The Company and myself or by 60 days advance written notice by either party. The minimum initial term of agreement covering any previous existing facilities unchanged by a new contract shall continue as stated on the original contract. The minimum initial term of agreement with all new facilities and any altered facilities shall begin with the completed installation date of the new facilities.
- If I request underground service, I will be responsible for installing all underground duct work to conform to The Company's specifications.
- No reduction in billing shall be allowed for any outage of less than ten working days after notification to The Company that a light is not operating.
- If I stop service during the initial term of the agreement, and a succeeding customer does not assume the same agreement for private lighting service at the same service address, I shall pay to The Company an amount equal to the monthly rate times the number of remaining months in the contract period.
- The service standards and other provisions relating to the service shall comply with applicable The Company's General Rules and Regulations.
- All equipment and facilities installed on the above premises will remain property of The Company.
- I hereby agree to indemnify, defend and save The Company harmless from all loss on account of injury, death or damage to persons or property on my real estate growing out of any intentional act, accident or mishap.

I have read and agree to the terms outlined above for a term of: ☐ one year ☐ three years ☐ five years

Customer Signature	Date of Customer Agreement	Representing the Company	Date Complete

GENERAL RULES AND REGULATIONS

CANCELLED ~~APPLYING TO ELECTRIC SERVICE (Ccontinued)~~

~~APPENDIX A (Ccontinued)~~

~~AGREEMENTS (C (continued)~~

~~(3) PRIVATE, UNMETERED, PROTECTIVE LIGHTING SERVICE INSTALLATION (continued)~~

~~KANSAS CITY POWER & LIGHT COMPANY~~

~~Sec. 1. The customer hereby applies to the Company for the private, unmetered protective lighting service designated herein and agrees to pay the Company for service received in accordance with the Company's applicable Rate Schedule and Regulations on file and in effect pursuant to State Regulatory Commission law during the period such service is furnished.~~

~~Sec. 2. The customer, If the owner of the premises, hereby grants, or if not the owner, will obtain from the owner upon request by the Company, an easement or easements granting to the Company the right to enter, locate, erect, install, operate, maintain, replace and remove the Company's facilities required for such service, together with any necessary entry and exit rights.~~

~~Sec. 3. The minimum initial term of this Agreement shall be one year. However, if service to the customer requires an extension of the Company's secondary circuit in excess of the installation of one pole, one circuit extension and/or the installation of additional transformer facilities, this Agreement shall be for an initial term of three (3) years. After the initial term, this Agreement shall continue in effect from month to month unless terminated by mutual agreement of the Company and the customer or by sixty (60) days advance written notice by either party. The minimum initial term of Agreement covering any previous existing facilities unchanged by a new contract shall continue as stated on the original contract. The minimum initial term of Agreement of all new facilities and any altered facilities shall begin with the completed installation date of the new facilities.~~

~~Sec. 4. If the customer requires underground service, the customer will be responsible for installing all underground ductwork to conform with Company specifications.~~

~~Sec. 5. If the customer stops service during the initial term of the Agreement, and~~