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Exhibit No.:	134 NP
Issue:	Minimum Filing Requirements: Revenues; Fuel Adjustment Clause; Property Tax Tracker; Vegetation Management Tracker; Critical Infrastructure Protection Tracker; Renewable Energy Standard Costs; Pre-MEEIA Opt Out; Depreciation Study; Customer Programs; Class Cost of Service; Electric Rate Design; Other Tariff Changes
Witness:	Tim M. Rush
Type of Exhibit:	Direct Testimony
Sponsoring Party:	Kansas City Power & Light Company
Case No.:	ER-2014-0370
Date Testimony Prepared:	October 30, 2014

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO.: ER-2014-0370

DIRECT TESTIMONY

OF

TIM M. RUSH

ON BEHALF OF

KANSAS CITY POWER & LIGHT COMPANY

Kansas City, Missouri
October 2014

Certain Schedules Attached To This Testimony Designated "(HC)" Contain Highly Confidential Information And Have Been Removed Pursuant To 4 CSR 240-2.135.

KCP&L Exhibit No. 134-NP
Date 6-15-15 Reporter AT
File No. ER-2014-0370

DIRECT TESTIMONY

OF

TIM M. RUSH

Case No. ER-2014-0370

Q: Please state your name and business address.

A: My name is Tim M. Rush. My business address is 1200 Main Street, Kansas City, Missouri 64105.

Q: By whom and in what capacity are you employed?

A: I am employed by Kansas City Power & Light Company ("KCP&L" or "Company") as Director, Regulatory Affairs.

Q: What are your responsibilities?

A: My general responsibilities include overseeing the preparation of the rate case, class cost of service ("CCOS") and rate design of both KCP&L and KCP&L Greater Missouri Operations Company ("GMO"). I am also responsible for overseeing the regulatory reporting and general activities as they relate to the Missouri Public Service Commission ("MPSC" or "Commission").

Q: Please describe your education, experience and employment history.

A: I received a Master of Business Administration degree from Northwest Missouri State University in Maryville, Missouri. I did my undergraduate study at both the University of Kansas in Lawrence and the University of Missouri in Columbia. I received a Bachelor of Science degree in Business Administration with a concentration in Accounting from the University of Missouri in Columbia.

Q: Please provide your work experience.

A: I was hired by KCP&L in 2001 as the Director, Regulatory Affairs. Prior to my employment with KCP&L, I was employed by St. Joseph Light & Power Company ("Light & Power") for over 24 years. At Light & Power, I was Manager of Customer Operations from 1996 to 2001, where I had responsibility for the regulatory area, as well as marketing, energy consultant and customer services area. Customer services included the call center and collections areas. Prior to that, I held various positions in the Rates and Market Research Department from 1977 until 1996. I was the Manager of that department for 15 years.

Q: Have you previously testified in a proceeding before the MPSC?

A: I have testified on many occasions before the MPSC on a variety of issues affecting regulated public utilities.

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to:

I. Explain how the Company satisfied the MPSC's minimum filing requirements ("MFR") under 4 CSR 240-3.030 for this rate case filing;

II. Explain and support the Company's annualized/normalized revenues;

III. Explain the challenges and risks facing the Company;

IV. Explain and support the Company's request for a Fuel Adjustment Clause ("FAC");

V. Explain and support the Company's request for a property tax tracker;

VI. Explain and support the Company's request for a vegetation management tracker;

VII. Explain and support the Company's request for a tracker mechanism to recover costs to comply with Federal Energy Regulatory Commission ("FERC") critical infrastructure protection ("CIP") and cybersecurity costs;

VIII. Explain and support the Company's request for recovery of Renewable Energy Standard ("RES") costs;

IX. Explain and support the Company's request for recovery of pre-Missouri Energy Efficiency Investment Act ("MEEIA") balance cost recovery;

X. Explain the Company's Depreciation Study Requirements;

XI. Customer Programs;

XII. Discuss the results of KCP&L's CCOS study;

XIII. Recommend the rate design and other tariff changes in this case.

I. MINIMUM FILING REQUIREMENTS

Q: What is the purpose of this part of your testimony?

A: The purpose of this part of my testimony is to confirm that KCP&L has satisfied the MPSC's MFR, as set forth in 4 CSR 240-3.030.

Q: How did KCP&L satisfy the MFR?

A: The following information was prepared and attached to the Company's Application filed concurrently with this testimony, to address the specific requirements of the MFR as outlined in 4 CSR 240-3.030(3):

A. Letter of transmittal

B. General information, including:

1. The amount of dollars of the aggregate annual increase and percentage over current revenues;

2. Names of counties and communities affected;

3. The number of customers to be affected;

4. The average change requested in dollars and percentage change from current rates;

5. The proposed annual aggregate change by general categories of service and by rate classification;

6. Press releases relative to the filing; and

7. A summary of reasons for the proposed changes.

II. ANNUALIZED/NORMALIZED REVENUES

Q: Were the retail revenues included in this filing prepared by you or under your supervision?

A: Yes, they were.

Q: Will you describe the method used in developing the revenues for this case?

A: Both the weather-normalized kWh sales and customer levels by rate class were developed by Company witness Albert R. Bass, Jr. Mr. Bass explains those figures in his Direct Testimony. The test year used by the Company in this case was 12 months ending March 31, 2014, which we expect will be updated for known and measurable changes through May 31, 2015. The monthly bill frequencies for the 12 months ending March 31, 2014, that contain the billing units for each of the billing blocks for the various rate components were developed under my supervision. For example, the residential general use rate has three billing blocks in the winter period, while only one billing block in the summer period. The bill frequency collects the actual usage that is billed in each of the billing blocks for each month of the test period. It also collects the actual number of customers in each of the months.

By applying the actual rates to the usage in each of the billing blocks, the actual revenues can be reproduced. This method provided the basis for determining the overall revenues to be used in this case. The Company determined monthly revenues by applying the normalized sales and customer levels for each month represented in the test period to the corresponding billing frequency. This was done for each month. The normalized sales and customer levels from this were then multiplied by the rates that took effect on January 26, 2013. The sum of these revenues was compared to the actual revenues for the test year ending March 31, 2014 to determine the revenue adjustment contained in the Summary of Adjustments attached to the Direct Testimony of Company witness Ronald A. Klote as Schedule RAK-4 (adjustment no. R-20).

III. CHALLENGES AND RISKS FACING THE COMPANY

Q: Do the rate case procedures normally used in Missouri provide a sufficient mechanism for KCP&L to recover the increasing level of costs that it is facing and still earn a fair return on equity?

A: Unfortunately, no. In an environment where costs are increasing rapidly and billing determinants that drive revenues (i.e., customer numbers and kWh sales) are flat to declining, the opportunity for utilities to earn a fair return is severely compromised by regulatory lag. Regulatory lag is the delay in the time between when the cost to provide service changes and the effective date for the new rates resulting from a rate case. While regulatory lag can work both ways, that is, it can serve to prolong both under-earnings and/or over-earnings, under the current environment – with escalating costs, the continued need to make capital expenditures and flat to declining revenues – KCP&L is experiencing prolonged under-earnings. A rate case in Missouri typically takes approximately 11 months to complete. KCP&L's significant costs of service have been increasing rapidly since the conclusion of its last rate case (new rates took effect in January 2013). Fuel and purchased power, transmission costs, and property taxes have all increased materially since KCP&L's last rate case, while actual revenues have decreased. Operation and maintenance costs have been held flat since the last rate case, but that cost control is not sustainable without damage to reliability and operational effectiveness. Consequently, due to the increase in costs primarily outside of the Company's control and the shrinking of rate revenues earned, KCP&L has experienced lower earnings than authorized. In fact, based on the annual surveillance report that the Company submits to the Missouri Public Service Commission each year, KCP&L's Missouri operations return on equity ("ROE") was 6.5% in 2013, the year immediately following the last rate increase in which the Commission authorized a 9.7% ROE.

Q: Are there ways in which the Commission could address this lag?

A: Yes. In this case, the Company is specifically asking for changes to the treatment of certain costs that would go a long way to alleviate the lag that currently exists in the traditional ratemaking process.

In 2006, the legislature enacted SB 179, which allows utilities to seek an FAC, a mechanism that permits utilities to adjust the price of electricity to reflect fluctuations in cost. The Company is requesting an FAC in this case.

Additionally, the Company is requesting a tracker mechanism for property taxes. Property taxes are government-imposed and essentially out of the control of the Company.

The Company is also requesting a vegetation management tracker to help in managing costs of the tree-trimming practices of the Company.

Lastly, the Company is requesting a tracker for costs associated with meeting CIP standards and cybersecurity requirements imposed by the North American Electric Reliability Corporation ("NERC") under authority delegated to it by the FERC.

Q: Why is approval of these mechanisms in this case so important?

A: Fuel, purchased power, transmission costs, off-system sales and property taxes are costs that are largely beyond the Company's control and are areas where we are facing significant increases in cost over the next several years. Without an adequate mechanism to timely recover these cost increases, KCP&L will not have a reasonable opportunity to earn its authorized return on equity now or in the foreseeable future. KCP&L will devote substantial resources to CIP and cybersecurity efforts over the next few years which are intended to protect customers' interests, however, the cost to be incurred for this work remains somewhat unclear and uncertain. With regard to the vegetation management tracker, the Company is proposing changes in its tree-trimming practices that will enhance reliability for customers. The tracker is being proposed to help balance the tree-trimming expenditures between rate jurisdictions in Missouri and Kansas, as well as balance them with GMO.

As will be described in more detail later in this testimony, these regulatory mechanisms will help to mitigate the impact of regulatory lag which has been driving

KCP&L's earnings well below the Commission-authorized level while also protecting customers from excess earnings driven by the items covered by these mechanisms.

Q: Why doesn't the traditional ratemaking process provide an adequate mechanism for KCP&L to recover its increasing costs in these areas?

A: The effect of regulatory lag in the traditional ratemaking process means that KCP&L will always face a time lag in recovering cost increases. Because of KCP&L's current low to no growth revenue environment and the magnitude of the costs identified in the FAC, the property tax tracker, the CIP cost tracker and vegetation management tracker, failure to recover even a small percent of those increased costs will have a significant adverse impact on the Company's earnings.

Such under-recovery of costs, over time, would undermine KCP&L's financial health and access to capital markets, potentially increasing the cost to customers by paying higher capital costs or potentially jeopardizing KCP&L's ability to maintain service levels and invest in its system. In addition to adversely affecting earnings, an under-recovery of costs compromises the Company's cash flows, further straining its financial health and limiting its access to credit. KCP&L competes for credit with other vertically integrated electric utilities in the Midwest and throughout the country, the vast majority of which already have FACs and other recovery mechanisms which better match cost recovery and cost incurrence. Attached and marked as Schedule TMR-1 is a schedule prepared by SNL which shows the various recovery mechanisms by state for investor-owned electric utilities.

It is also important to remember that these are not one-way mechanisms, that is, they protect customers from paying higher than actual costs while also protecting the Company from under-recoveries regarding those same cost items.

IV. FUEL ADJUSTMENT CLAUSE

Q: Does the Company currently have an approved FAC?

A: No.

Q: Please explain why the Company does not have an FAC.

A: While the three other Missouri electric utilities have FACs in place, KCP&L does not pursuant to the agreement reached in its Experimental Regulatory Plan, Case No. EO-2005-0329, which became effective August 7, 2005, was amended by order effective August 23, 2005, and resulted in the Company's "Comprehensive Energy Plan" or "CEP." In that case, the parties entered into a stipulation and agreement that included a number of conditions, including that the Company would not seek to utilize an FAC *prior to* June 1, 2015. As rates and tariff changes from this case, including the FAC are expected to become effective in late September 2015, this condition has been met.

Q: What are the rules for establishing an FAC?

A: The requirements for establishing an FAC are found in Section 386.266 RSMo and Commission Rules 4 CSR 240-20.090 and 4 CSR 240-3.161. As part of my Direct Testimony, I include the information required for an FAC in the attached Schedules TMR-2 through TMR-4.

Q: Are you sponsoring this information?

A: Yes, I am.

Q: Was this information prepared by you and/or under your direct supervision?

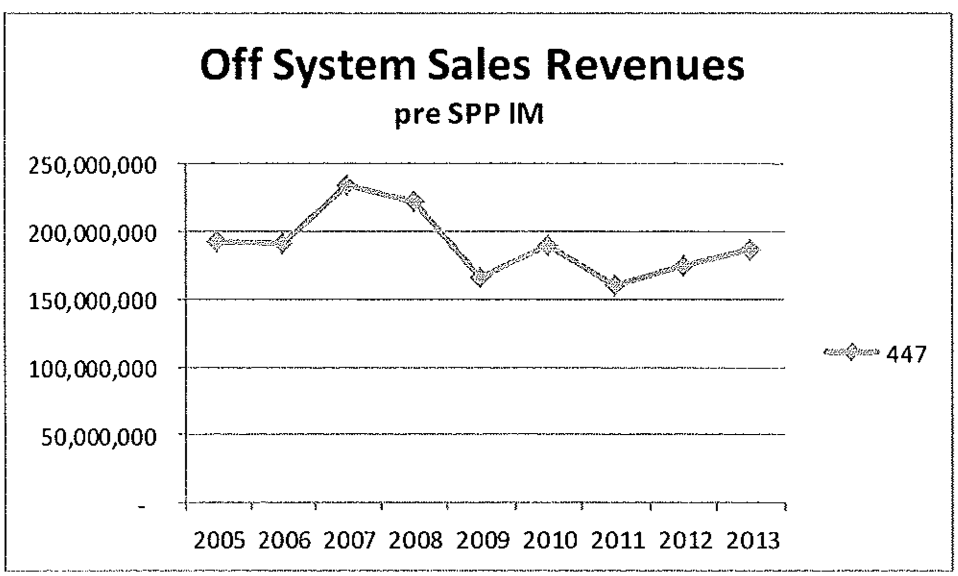
A: Yes, it was.

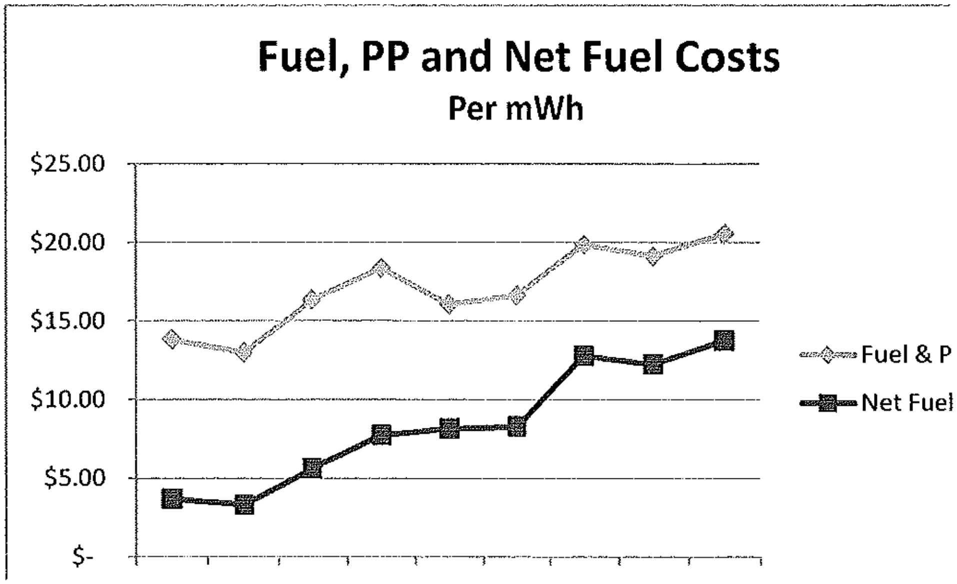
THE NEED FOR A FUEL ADJUSTMENT CLAUSE

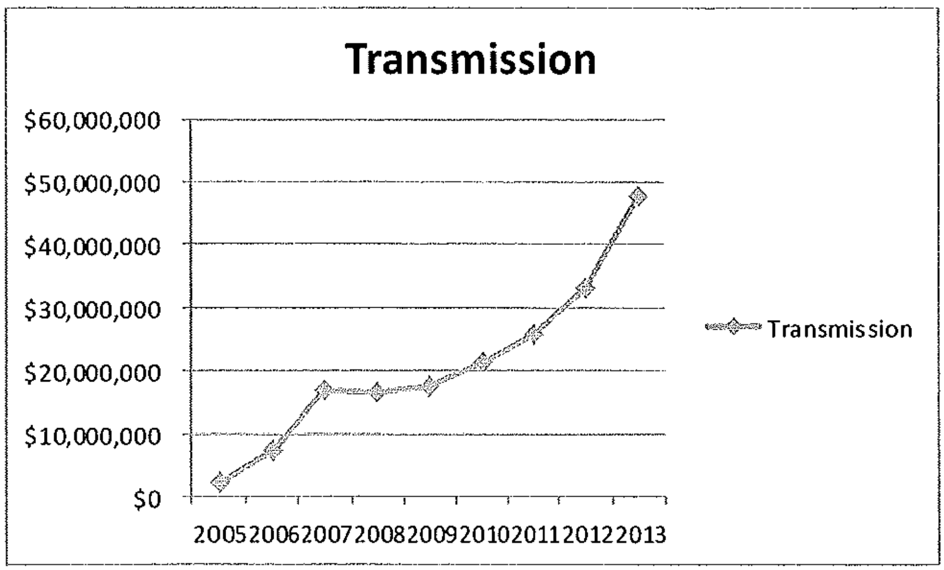
Q: Why is KCP&L requesting an FAC in this case?

A: The Company has experienced significant cost increases in the fuel, purchased power and transmission areas in recent years. The three tables below demonstrate the changes in costs since 2005 for off-system sales revenues, transmission costs and fuel and purchased power costs. The table identified as Fuel and Purchased Power includes the line identified as net fuel costs. This line identification includes off-system sales, transmission and fuel and purchased power costs combined. This would represent the components that the Company is requesting as the components of the fuel adjustment.

Please see the following charts for a view of the volatility related to these items.







The current method of filing a rate case to include cost increases does not allow for the recovery of the costs going forward, but only looks at a historic level. The FAC will, prospectively, address those rising fuel, purchased power (offset by off-system sales) transmission costs and revenues. Doing so will allow for the recovery of prudently incurred costs while at the same time protecting customers from bearing costs that are higher than the Company actually incurs.

KCP&L's last rate increase went into effect on January 26, 2013. While that rate increase addressed the historical increases in fuel, purchase power and transmission costs, KCP&L's Missouri operations experienced fuel and purchased power costs increases of nearly $4 million, Wholesale revenues were down nearly $8 million and transmission costs increases were just under $7 million in 2013. None of these amounts were reflected in the rate increase that went into effect that January. This increase in costs of over $29 million was not recovered from customers. As a result, the Company had to absorb those increases. While the Commission authorized an ROE of 9.7% for KCP&L's Missouri operations, the Company was able to earn only 6.5% ROE in 2013, with one of the primary reasons driven by increases in fuel, purchased power and transmission costs.

Therefore, one of the primary drivers for the Company's FAC request is to implement a mechanism that will allow for recovery of the increases (or return of decreases) in fuel, purchased power and transmission costs, offset by off-system sales revenues and transmission revenues that will occur beyond the effective date of any rate increase granted in this rate case. An FAC will also allow the Company the opportunity to earn a fair return in order to generally preserve its financial health.

A base rate increase is therefore essential at this time just to permit the Company to recover its current fuel, purchased power and transmission costs offset by revenues, and an FAC is essential to address continuing uncertainty and volatility in these costs as well as increases in costs that are expected to continue. An FAC also protects customers from paying higher costs than the Company actually experiences.

Q: You noted that the FAC is needed to address increasing, volatile and uncertain fuel, purchased power and transmission costs, and to ensure the Company has an opportunity to earn a fair return in order to generally preserve its financial health. How large are KCP&L's fuel costs?

A: Based on the normalized test year values filed in this rate case, KCP&L's total fuel and purchased power, transmission, net of off-system sales and transmission revenues are $152 million per year, which is roughly 20% of total retail revenues.

Q: Why do you believe that in the absence of an FAC the Company would not have a sufficient opportunity to earn a fair rate of return?

A: My belief is based both on the experience of the Company since its last rate case and on common sense. As noted above, the Company experienced significant increases in fuel, purchased power and transmission costs net of off system sales and transmission revenues in 2013 that were not reflected in the rate increase that went into effect in January 2013.

Without the proposed FAC, under the environment KCP&L expects where fuel, purchased power and transmission costs, as well as off-system sales experience, continue to increase cost of service, the Company will not have a reasonable opportunity to earn the rate of return that the Commission authorizes in this case. Conversely, if fuel, purchased power and transmission costs, as well as off-system sales and transmission revenues, prove to lower cost of service after the setting of base rates, then the presence of an FAC will protect customers from paying higher costs than the Company actually experiences.

Q: Couldn't these cost increases be recovered through a normal rate case?

A: No. The regulatory lag issue that I describe above prevents the Company from recovering much of these costs. Under traditional ratemaking using a historical test year, even if a rate case were timed so that a rate case were filed the day after rates became effective, KCP&L would have to absorb the cost increases between the true-up period from one rate case until the next true-up period in the next case. In the last rate case that went into effect in January 2013, the true-up period for fuel costs was August 2012. Cost increases after August 2012, are not reflected in the January 2013 rates and are absorbed by shareholders until the new rates go into effect. This rate case filing anticipates rates going into effect at the end of September 2015. If the true-up period in this case is May 2015, then the fuel cost changes between August 2012 and May 2015 are not recovered in rates. This is nearly 36 months. Without the FAC in this case, this lag will continue.

Q: Couldn't off-system sales revenues increase to offset the known fuel cost increases KCP&L is facing?

A: Possibly. Future off-system sales revenues could be higher or lower than the normalized amount that the Commission sets in this rate case, and although we certainly hope that increases in off-system sales margins would at least partially offset fuel cost increases. But as can be seen from the chart above, off-system sales experience is considerably variable. Off-system sales constitute a significant cost of service item that is subject to market force impacts that are beyond KCP&L's control. The proposed FAC mechanism not only protects the Company against these uncertainties, but also reflects any decreases in fuel, purchased power and transmission costs, as well as increases in off-system sales and transmission revenues that would benefit customers.

Q: **You mentioned that in addition to the sharp rise in fuel costs, KCP&L is exposed to continuing volatility and uncertainty with regard to fuel costs. Has KCP&L analyzed the sources and magnitude of this volatility and uncertainty?**

A: Yes. The volatility and uncertainty in the Company's net fuel costs is addressed in the Direct Testimony of KCP&L witness Wm. Edward Blunk.

Q: **Why are KCP&L's net fuel costs so volatile, if KCP&L mostly relies on coal and nuclear generation and both its coal and nuclear costs are partially hedged in the next few years?**

A: Net fuel costs are a function of many variables that are substantially beyond the control of KCP&L, notably loads, fuel prices, power market prices, transportation costs, and generation availability. The volatility of net fuel costs is caused by off system sales revenue. As demonstrated by the graph above, off system sales revenues fluctuate significantly from year to year. While this means KCP&L's customers realize substantial savings from off-system sales (in the form of a lower revenue requirement and the resulting lower rates), it also means that KCP&L's exposure to volatile power prices is comparable to that of a company that supplies its customers in large part through power purchases. The point is that nobody knows with any level of certainty what these commodity prices will do in the future, which creates a great deal of uncertainty around net fuel costs.

Q: **Does KCP&L have significant control over the increases, volatility and uncertainty in fuel costs it faces?**

A: No. The fuel costs faced by KCP&L are largely outside the Company's control. While the Company works very hard to purchase fuel at the lowest possible cost consistent with minimizing volatility and maximizing revenues from off-system sales, KCP&L does not have any meaningful control over the fundamental market conditions affecting fuel cost increases and market volatility.

The primary cost items that would be tracked in the proposed FAC are coal, coal transportation, natural gas, oil, nuclear fuel, wind, oil and purchased power net of revenues from wholesale sales to others and transmission costs and revenues.

THE PREVALENCE OF FAC'S IN OTHER STATES

Q: In the order approving an FAC for Aquila, Inc. ("Aquila"), the Commission noted that other states' experiences with FACs can be instructive in making its decision whether to grant requests for an FAC. What are other states' experiences with FACs?

A: When it approved Aquila's FAC, (Case No. ER-2007-0004, page 31) the Commission noted that outside of Missouri, all but two of the 29 non-restructured states without retail competition allow their electric utilities to apply to recover fuel and purchased power costs through some type of FAC. One of the two states that did not was Vermont, which now also allows FACs through alternative regulatory plans and has already implemented an FAC for one of its two utilities.

Q: Are FACs prevalent in other Midwestern states, many of which are served by coal-intensive utilities similar to KCP&L?

A: Yes. In fact, FACs are even more prevalent in the surrounding states. As also shown in Schedule TMR-1 utilities in surrounding non-restructured Midwestern states are already operating with the benefit of an FAC.

Q: Why is it important that other regulatory agencies have approved an FAC for utilities in their jurisdiction?

A: As the Commission itself has already recognized, FACs are used by the overwhelming majority of utilities in other non-restructured states. It is both instructive that state commissions in those states have approved FACs for their utilities—even for their coal intensive utilities—and crucial that KCP&L be able to compete for capital on an even footing with those utilities. Because KCP&L must compete for capital with those utilities, it will be at a disadvantage if those utilities have more robust earnings, more certain cash flows, and greater financial strength. KCP&L will be disadvantaged in its access to capital markets and the return that will be required by investors will be higher. This would translate to higher rates for KCP&L customers in the long-term.

TRANSMISSION COSTS

Q: What is the Company's proposal regarding the recovery of transmission costs?

A: The Company requests that transmission costs associated with the charges and revenues from Southwest Power Pool ("SPP") billings, and transmission costs to buy and sell energy, be recovered in rates through the FAC mechanism. This will provide for a direct link between transmission associated with the sale and purchase of energy and ensure appropriate recovery of transmission costs billed by SPP. Transmission costs incurred for the operation of KCP&L will not be included in the FAC, but will be recovered through base rates. This is consistent with the current treatment of transmission costs at AmerenUE Missouri.

By way of recent history, in its last rate case (Case No. ER-2012-0174), KCP&L requested a transmission tracker for those costs being billed by SPP. It was a contested issue before the Commission. In the Report and Order for the case, the Commission ruled that the Company had the ability to implement a tracker accounting mechanism without requiring Commission approval. The Company sought rehearing of that decision arguing that it was necessary to receive Commission approval to implement such a mechanism. The Commission denied the request.

As a result, the Company filed a request for an Accounting Authority Order ("AAO") allowing the Company to track the increases in transmission costs since its last rate case (Case No. EU-2014-0077). The Commission denied the application, but indicated that the Company could include transmission costs in an FAC in the Company's next rate case. In that Order under the Finding of Facts, the Order quotes in paragraph 12:

> 12. The transmission expenses for which Companies seek an AAO are the type of expenses which may be collected through a Commission approved Fuel Adjustment Charge ("FAC") authorized during a general rate case proceeding. GMO currently has an FAC; however, it does not include the transmission costs requested in the Application.

Q: Why is the recovery of transmission costs through the FAC appropriate?

A: Transmission costs are directly linked to the Company's fuel and purchased power requirements, particularly because of the new SPP Integrated Marketplace ("SPP IM"), also called the Day Ahead market established at the SPP. Transmission costs can vary significantly from year-to-year, and such costs are a material cost of service component. Historically, transmission costs have fluctuated due to load variations, both in serving native customers to the service territory and in off-system sales. Added factors are the SPP's regional transmission upgrade projects that are part of its transmission expansion plans, and increasing SPP administrative fees, both of which have increased KCP&L's costs significantly and will continue to increase costs in coming years.

Q: What factors are driving the transmission expansion plans?

A: A major factor is the push for renewable energy resources in the region, in particular wind generation. Significant transmission upgrades are necessary to capture the full potential of wind resources in the region. Other major drivers of new upgrades and the need to reduce congestion on key transmission paths in order to facilitate more efficient power markets and investments to improve transmission reliability. These factors are driven by the need to comply with FERC directives and the Company has no ability to avoid paying these SPP-allocated transmission costs.

Q: Please describe the transmission planning and cost recovery mechanisms used by the Company prior to facilities being placed under SPP's functional control.

A: Before the Company's transmission facilities were placed under SPP's functional control, it planned its transmission system to serve retail customers within its franchised service territory. The costs of these transmission facilities were recovered from retail ratepayers through rates approved by this Commission and the FERC. The Company is obligated to serve retail customers within its franchised service territory that seek service. For decades, the Company has built, and it will continue to build, transmission facilities that are necessary to reliably serve its retail load (e.g., generation interconnection or transmission service requests from customers within its franchised service territory). The Company is not requesting that transmission O&M costs or return on assets owned by the Company and associated with directly serving retail customers be included in the FAC mechanism.

Q: How did the cost allocation method change once SPP became an RTO?

A: After receiving RTO status in 2004, SPP began planning regionally to meet the needs of its transmission customers. The regional focus of the RTO created the need for regional allocation of the resulting costs, in order to effectively meet the needs of the SPP region as a whole instead of utility by utility.

SPP worked with the Regional State Committee, a committee comprised of retail regulatory commissioners from agencies in the states SPP administers transmission service, to develop and implement cost allocation methodologies that allocate costs of SPP-approved projects to the entire region.

Q: How are SPP transmission costs allocated to KCP&L expected to change?

A: SPP transmission costs allocated to KCP&L have been rising, and projections show that these expenses will continue to increase at a significant rate from 2014 through 2019. As can be seen in Schedule TMR-5, base plan transmission costs allocated to KCP&L, for both wholesale and retail transmission service, were approximately $22.8 million for the calendar year 2013, and they are projected to increase to $55.1 million in 2017. SPP further projects KCP&L's share of the SPP transmission costs to peak at over $65 million in 2022. This equates to a substantial increase of approximately 16% per year from 2013-2022. These projections reflect both zonal and region-wide components of the costs of SPP-approved projects and the increases are primarily driven by the region-wide components.

Q: Please describe the SPP administration charge.

A: As an RTO, SPP is a transmission provider currently administering transmission service over portions of Arkansas, Kansas, Louisiana, Missouri, Nebraska, New Mexico, Oklahoma and Texas. The Company is a member of, and has transferred control over its transmission facilities to SPP. With the exception of certain grandfathered agreements, transmission service over the Company's transmission facilities is provided pursuant to the SPP Open Access Transmission Tariff ("OATT"). SPP exercises functional control over all of the Company's transmission assets, and offers point-to-point and network integration transmission services and generator interconnections on the Company's transmission system pursuant to the OATT.

The SPP is a not-for-profit entity that must remain revenue neutral; its costs must be recovered from its users (transmission customers). Consequently, the Company pays SPP an administration charge for performing the aforementioned RTO functions on its behalf.

Q: **Why is SPP's administration charge increasing?**

A: SPP obtained FERC approval to increase the rate cap on its administration charges from \$0.35/MWh to \$0.39/MWh. Since 2008, the administration charge rate cap was set at \$0.225/MWh and SPP was able to fully recover its expenses and remain under this cap through 2011. However, due to increases in expenses primarily associated with the ongoing development and implementation of the SPP IM, SPP requested and received FERC approval to raise the administration charge cap to \$0.35/MWh effective January 1, 2012[1], and subsequently to raise the cap to \$0.39/MWh effective January 1, 2014. Consequently, the administration charge set forth in Schedule 1-A has increased from \$0.315/MWh beginning January 1, 2013 to \$0.381/mWh beginning January 1, 2014.

[1] Southwest Power Pool, Inc., FERC Docket No. ER12-277-000, Letter Order (issued Dec. 14, 2011) (accepting SPP's proposed tariff changes).

Recently, SPP staff has indicated the need to increase the Schedule 1-A rate cap again in order to recover a 2013 and projected 2014 shortfall. However, SPP members represented on the SPP Finance Committee have implored SPP to do everything in its power to reduce costs in order to stay within the current cap of $0.39/MWh. Effective, October 2014, the SPP Board of Directors approved a rate of $0.39/MWh.

Q: What transmission costs, specifically, is KCP&L proposing to be included in the FAC?

A: KCP&L is proposing that costs included in FERC Account 565 (standard point-to-point transmission charges and base plan funding), SPP Schedule 1-A fees charged to Accounts 561 and 575, and FERC Schedule 12 fees charged to Account 928 offset by transmission revenues accounted for in FERC Account 456.1 be included in the FAC.

Q: Is this amount requested in the case supported by other Company witnesses in this case?

A: Yes. Company witnesses Ronald A. Klote supports these amounts in his Direct Testimony of adjustments CS-45 (Transmission of Electricity by Others), CS-85 (Regulatory Assessments- Schedule 12 Fees) and CS-86 (Schedule 1-A Fees).

FERC TRANSMISSION ADJUSTMENTS

Q: Is the Company making transmission and Transource related adjustments to its proposed FAC?

A: Yes, the Company has made the following adjustments: (1) remove SPP charges directly related to Transource's Transmission Incentives pursuant to a Non-Unanimous Stipulation and Agreement in Case No. EA-2013-0098 dated April 12, 2013; and (2) normalize wholesale transmission revenue to reflect revenue earned through the Transmission Formula Rate at a ROE level reflective of this case.

DESCRIPTION OF THE PROPOSED FAC

Q: Please describe the general design and intended operation of the proposed FAC.

A: KCP&L's proposed FAC tariff is attached as Schedule TMR-4. The Company proposes to recover its normalized test-year level of fuel, purchased power and transmission costs (offset by off-system sales revenues and transmission revenues) through its base rates. To that end, $0.01547 per kWh in net fuel and purchased power costs at the generation level has been included in base rates, and includes the transmission of electricity by others costs and fees as discussed above. The proposed FAC is applicable to all energy supplied to all Missouri retail customers served by the Company.

The $0.01547 per kWh of net base fuel costs was calculated by taking the sum of: (a) the normalized fuel and purchased power costs determined from the production cost modeling; and (b) additional fuel and purchased power cost components (principally net SPP IM charges), reduced by normalized off-system sales revenues and including transmission costs and transmission revenues. This is the amount that is included in base rates.

Deviations in actuals from this amount for the like accounts will be accrued over two separate six-month Accumulation Periods — October through March and April through September. Any FAC adjustment resulting from actual net fuel cost deviations incurred during an Accumulation Period will be flowed through, with interest, over the 12-month Recovery Period commencing three months after the close of the Accumulation Period. In other words, any adjustment resulting from cost deviations incurred during the October 2015 through March 2016 Accumulation Period (to be filed by May 1, 2016) would be recovered over the July 2016 through June 2017 Recovery Period. Similarly, cost deviations attributable to the April through September Accumulation Period (to be filed by November 1, 2016) would be recovered during the January 2017 through December 2017 Recovery Period, and so on. Staggering the adjustments and recovery periods in this manner will minimize rate volatility and seasonal fluctuation for customers, since accumulated variations would be recovered over a full 12-month period. The operation of the Accumulation and Recovery Periods are illustrated in Schedule TMR-6, attached to this testimony.

Q: What costs are included in the FAC?

A: As described above, the FAC would include all fuel and purchased power costs incurred to serve retail customers and the portion of off-system sales allocated to Missouri retail ratepayers, net of the Company's off-system sales revenues and including transmission of electricity by others costs and revenues that are allocated to KCP&L Missouri ratepayers. A more detailed description of the costs and revenues addressed by the FAC is included in the FAC formula set forth in Schedules TMR-2 and TMR-4.

Q: Has the Commission included similar costs in the FACs it has approved for other Missouri utilities?

A: Yes. Of the FACs currently in place for the three other Missouri utilities, all are similar in design and recover the same types of costs with one exception. The FAC of AmerenUE Missouri differs slightly from those of The Empire District Electric Company and of KCP&L Greater Missouri Operations Company in that AmerenUE Missouri recovers transmission costs through the FAC.

Q: Does KCP&L's proposed FAC tariff include off-system sales revenues?

A: Yes. As noted earlier, the proposed FAC includes both revenues from off-system sales achieved by KCP&L and the fuel costs associated with these off-system sales. This process reduces native load fuel and purchased power costs by the profits achieved on off-system sales (i.e., the off-system sales margin), and results in a significantly lower normalized level of net fuel costs to be recovered from native load customers.

Q: Please briefly explain some of the changes that have occurred since the Company's last rate case that impact the fuel, purchased power and transmission costs, as well as off-system sales markets.

A: The Company had been preparing over that last several years to enter the SPP IM in March 2014. This has been a major undertaking. Essentially, this market is a fundamental change in the overall structure of buying and selling energy. In March, the Company turned over the function of dispatching its generation resources to SPP and now bids its generation resources into SPP. SPP, in turn, makes the decision on which generation units to dispatch over the entire SPP footprint to serve the overall load of the SPP market. No longer does KCP&L use its generation resources to directly serve its retail customers; instead, it buys its retail load needs from the SPP market. As a result, KCP&L bids all of its generation resources into the SPP market and buys its entire retail load from that same market. If, at any time, it is generating more than it is buying, there will be a net positive contribution to the Company. Accordingly, the Company does not now identify off-system sales margins as it has traditionally done. Company witness Burton Crawford discusses this SPP Integrated Marketplace in his Direct Testimony.

Q: Does KCP&L's proposed FAC include a provision that limits recovery or return through the FAC to 95%, as currently exists in other Missouri utilities' FACs?

A: No.

Q: Why are you not including the 95% limitation on recovery?

A: The vast majority of FACs in place for electric utilities in this part of the country reconcile recovery at the 100% level. KCP&L competes for capital with these companies and would be disadvantaged if its FAC limits recovery through the FAC to 95%. So too would its customers not see the benefit of a 100% reconciliation should recovery be limited. It is also important to remember that fuel costs are volatile. Because fuel costs are not controlled by the Company it is only fair that customers should enjoy 100% of the benefits of fuel cost reductions and that the Company should recover 100% of fuel cost increases.

Q: Does KCP&L's proposed FAC apply different adjustment factors to customers receiving service at different voltage levels?

A: Yes. In accordance with 4 CSR 240-20.090(9), the proposed tariff applies two separate voltage level adjustment factors to customer classes taking service at different voltage levels—primary service customers and secondary service customers.

Q: How will the proposed FAC be trued-up to reflect over- or under-collections over time?

A: The FAC will be trued-up on an annual basis after the completion of each true-up year. True-up filings will continue until all recoverable deviations from net base fuel costs that have been accumulated and deferred have been recovered and trued-up. Any true-up adjustments will also include interest, pursuant to the Commission's FAC rule 4 CSR 240-20.090(5)(A) and the FAC tariff.

Q: How will KCP&L address any issues regarding the amount included in the FAC?

A: Any issues or concerns will be addressed in a prudence review. As outlined in the attached tariff, prudence reviews will be conducted no less frequently than eighteen (18) month intervals.

Q: Is the Company requesting carrying costs on the amounts added to the regulatory asset or regulatory liability?

A: Yes, interest will be calculated monthly at a rate equal to the weighted average interest paid on the Company's short-term debt, applied to the month-end balance of the regulatory asset or liability associated with deferred fuel adjustment clause costs.

V. PROPERTY TAX TRACKER

Q: Is the Company proposing a property tax tracker?

A: Yes. The Company requests that a property tax tracking mechanism be authorized in this case to ensure the appropriate recovery of rising property tax expenses. The Company's request for a property tax tracker would be treated similarly to the tracking mechanism for most other tracking mechanisms in Missouri. This would be similar to tracking mechanisms at The Empire District Electric Company's vegetation management/infrastructure inspection and pension trackers, and Ameren Missouri's SO_2, vegetation management and pension trackers, as well as KCP&L's and GMO's pension trackers.

Q: Why is a tracker appropriate for KCP&L's property tax expenses?

A: Property tax is another primary driver for this rate case and the Company is requesting a tracker mechanism, similar to the request in the last rate case. As KCP&L's costs continue to rise, the pattern of under-earnings will only get worse.

Property tax expenses have been escalating over past five years as described more fully by Company witness Ronald A. Klote. Property taxes are determined by Missouri state assessors, are a significant component of the Company's cost of service, and amounts assessed are out of the control of the Company to manage. Cost of service components, such as property taxes, that are out of Company management's control to contain or manage are significant contributors to regulatory lag and impact the Company's ability to earn returns reasonably close to returns allowed by this Commission. Additionally, in the event of declines in property tax levels in the future, a tracker will protect customers from property tax costs higher than those actually experienced by the Company. Property taxes, like pension costs, are costs ideally addressed through regulatory mechanisms such as riders and trackers.

Q: How does the Company propose that a property tax tracker be implemented?

A: We propose that annual property tax expenses, as defined in this tracker, be set in this rate proceeding at the expense level determined in the true-up in this case. The Company would then track its actual property tax expenses on an annual basis against this amount, with the Missouri jurisdictional portion of any excess treated as a regulatory asset (Account 182) and the Missouri jurisdictional portion of any shortfall treated as a regulatory liability (Account 254).

Q: Is the base amount supported by other Company witnesses in this case?

A: Yes, Company witness Ronald A. Klote supports this amount in his discussion of adjustment CS-126 (Property Tax Expense).

Q: Is the Company requesting carrying costs on the amounts added to the regulatory asset or regulatory liability for the period before amounts are included in rate base?

A: Yes. The Company is requesting that carrying costs be accrued on amounts. The carrying costs would be calculated monthly by applying the monthly short-term interest rate to the account balance.

Q: How would the regulatory asset or liability be dealt with in KCP&L's next rate case?

A: We propose that the regulatory asset or liability be amortized to cost of service in the Company's next rate proceeding over the same length of period as costs are accumulated. The Company would reset the level of ongoing property tax expense in base rates in the next rate case, similar to how ongoing pension costs are reset each case.

VI. VEGETATION MANAGEMENT TRACKER

Q: Is the Company proposing a vegetation management tracker?

A: Yes. The Company requests that a vegetation management tracking mechanism be authorized in this case to ensure the appropriate recovery of rising expenses and to help better manage the cyclical nature of tree-trimming throughout the service territory as well as in the Kansas and GMO rate jurisdictions, where we will also seek authority to implement vegetation management cost trackers. Use of a tracker for vegetation management costs will enable the Company to schedule and perform this work in the most efficient manner by, for example, concentrating resources and efforts on a particular portion of the service territory, while still meeting all requirements, without creating the perception that the Company is spending a vegetation management rate allowance for one rate jurisdiction on vegetation management efforts in a different rate jurisdiction. Without a vegetation management tracker, the Company would tend to spread the work ratably over each rate jurisdiction which is likely not the most efficient way to accomplish this work.

The Company's request for a vegetation management tracker would be treated similarly to the tracking mechanism for most other tracking mechanisms in Missouri. This would be similar to tracking mechanisms at The Empire District Electric Company's vegetation management/infrastructure inspection and pension trackers, and Ameren Missouri's SO_2, vegetation management and pension trackers, as well as KCP&L's and GMO's pension trackers.

Q: **Why is a tracker appropriate for KCP&L's vegetation management expenses?**

A: Vegetation management expenses have been escalating over recent years as described more fully by Company witness Jamie Kiely. In addition, the Company is proposing to expand its tree trimming activities to address three specific areas that are not currently in the rules for vegetation management, but which will enhance customer reliability.

Q: **How does the Company propose that a vegetation management tracker be implemented?**

A: We propose that annual vegetation management expenses, as defined in this tracker, be set in this rate proceeding at the expense level determined in the true-up in this case. The Company would then track its actual vegetation management expenses on an annual basis against this amount, with the Missouri jurisdictional portion of any excess treated as a regulatory asset (Account 182) and the Missouri jurisdictional portion of any shortfall treated as a regulatory liability (Account 254).

Q: Is this amount supported by other Company witnesses in this case?

A: Yes, Company witnesses Ronald A. Klote and Jamie Kiely support this amount in their discussion of adjustment CS-43 (Vegetation Management).

Q: Is the Company requesting carrying costs on the amounts added to the regulatory asset or regulatory liability for the period before amounts are included in rate base?

A: Yes. The Company is requesting that carrying costs be accrued on amounts. The carrying costs would be calculated monthly by applying the monthly short term interest rate to the account balance.

Q: How would the regulatory asset or liability be dealt with in KCP&L's next rate case?

A: We propose that the regulatory asset or liability be amortized to cost of service in the Company's next rate proceeding over the same length of period as costs are accumulated. The Company would reset the level of ongoing vegetation management expense in base rates in the next rate case, similar to how ongoing pension costs are reset each case.

VII. CRITICAL INFRASTRUCTURE PROTECTION/CYBERSECURITY(CIP)

Q: Is the Company proposing a CIP tracker?

A: Yes. The Company requests that a CIP tracking mechanism be authorized in this case to ensure recovery of costs necessary to address the government mandated requirements regarding security of cyber assets essential to the reliable operation of the electric grid. The CIP tracker would be treated consistent and similar to other tracking mechanisms in Missouri.

Q: What is CIP, and what is the importance of CIP in this case?

A: As discussed in the testimony of Company witness Darrin Ives and repeated here, the FERC designated the NERC the Electric Reliability Organization ("ERO") in accordance with Section 215 of the Federal Power Act, enacted by the Energy Policy Act of 2005. As a result, NERC's Reliability Standards became mandatory within the United States. These mandatory Reliability Standards include CIP standards, which address the security of cyber assets essential to the reliable operation of the electric grid. To date, these standards (and those promulgated by the Nuclear Regulatory Commission) are the only mandatory cybersecurity standards in place across the critical infrastructures of the United States. Subject to FERC oversight, NERC and its Regional Entity partners enforce these standards. The Company is subject to these reliability standards, which include the CIP standards.

Q: What is "CIP Version 5"?

A: The CIP standards represent the portion of the full NERC reliability standards library focused on security of the infrastructure supporting reliable operation of the Bulk Electric System ("BES"). Due to the fluid nature of security threats to the critical infrastructure, the standards have continued to evolve to strengthen industry's approach in response to those threats. These responses are compliance obligations as well as additional protective measures that may not be mandated. Version 5 ("V5") of the CIP standards includes ten new or modified Reliability Standards, which expand the scope of the cyber systems that the current standards protect, as well as strengthen protections required for assets that are currently in scope.

Q: What is the effective date of CIP V5?

A: The standard is effective April 1, 2016.

Q: What is the Company requesting regarding CIP in this case?

A: Security is a top priority for the Company. KCP&L is committed to and required to comply with the standards set out in CIP V5. The standards to be implemented in 2016 are much more aggressive in broader coverage of the Company's assets supporting the BES. These cyber systems, as they are referenced in the V5, will require additional actions as well as resources for both physical and logical protection in support of reliability of the BES. The CIP standards represent only a portion of the Company efforts around strengthening physical and cyber security in protection of the Company's assets. This protection is necessary to ensure KCP&L is positioned to provide services to customers reliably given the emerging threats to the United States and her infrastructure. The cost to comply is undetermined, but is expected to be substantial. The Company has already committed significant resources toward compliance. Going forward, those efforts and resources will be increasing. The Company is asking the Commission to authorize it to establish a tracker for these costs. The amounts above those costs that will be included in base rates will be tracked for recovery consideration in a future rate case.

Q: What is the cost to comply with these requirements?

A: The cost to comply is undefined at this time, but will be substantial. KCP&L is working diligently to develop an overall cost plan. As noted in Mr. Ives' Direct Testimony, the Company has already committed substantial resources toward compliance and the effort and resources going forward will be increasing. The plan is to establish an amount reflecting personnel hired directly attributable to the CIP in the true-up and also include any defined costs that may have already been incurred.

Q: Is this like asking the Commission for a blank check?

A: No. First, the government mandated requirements have a cost to them, but as of yet it is currently undefined. The Company is asking the Commission to authorize it to establish a tracker for these costs. These costs will include the addition of personnel, substantial computer software enhancements and support and the development of new programs to address hardening of the Company's infrastructure. As this case proceeds, these costs will become better defined. The Company will establish specific projects ID's to track all costs associated with each specific project. The Company will be able to track these costs for recovery in a future case. Additional personnel that are added before the test year true-up will be included in the overall case, but many of the costs will not be incurred before the true-up, but shortly thereafter and during the remainder of 2015 and early 2016.

Q: Is the Company requesting carrying costs on the amounts added to the regulatory asset for the period before amounts are included in rate base?

A: Yes. The Company is requesting that carrying costs be accrued on amounts deferred. The carrying costs would be calculated monthly by applying the monthly short term interest rate to the account balance.

Q: How would the regulatory asset be dealt with in KCP&L's next rate case?

A: We propose that the regulatory asset be amortized to cost of service in the Company's next rate proceeding over a five year period. The Company would reset the level of ongoing CIP V5 expense in base rates in the next rate case, similar to how ongoing pension costs are reset each case.

VIII. RENEWABLE ENERGY STANDARD (RES)

Q: Please provide an overview of Sections 393.1020, 393.1025 and 393.1030 RSMo.

A: The statute was approved by a statewide voter referendum in 2008 known as Proposition C. The statute establishes renewable energy standards for Missouri investor owned electric utilities. Electric utilities must generate or purchase renewable energy credits ("RECs") or solar renewable energy credits ("S-RECs") associated with electricity from renewable energy resources in sufficient quantity to meet both the RES requirements and the RES solar energy requirements respectively on a calendar year basis.

An electric utility is required to have at least two percent of its RES requirement derived from solar energy.

Section 393.1030 also established a solar rebate program for customers who install solar electric systems. Customers installing solar electric systems could receive a rebate of two dollars ($2.00) per installed watt up to a maximum of twenty-five (25) kW per retail account. For example, a customer who installs a 25 kW solar electric system receives a rebate from the utility of $50,000. Additionally, customers who install solar electric systems qualify for net metering, which allows the solar electricity generated to be netted on their electric bill on a monthly basis. The solar rebates are phased out over a period of four years and end June 2018.

Section 393.1030 RSMo. also requires customers to give the S-RECs to the utility for a ten-year period in exchange for the rebate payment.

Section 393.1030.2(4) allows for RES cost recovery and pass-through of RES benefits outside of a general rate proceeding through a Renewable Energy Standard Rate Adjustment Mechanism ("RESRAM"). The Commission established 4 CSR 240-20.100

to provide rules and regulations governing the Electric Utility Renewable Energy Standard Requirements.

Q: Please describe what you are requesting with regard to the RES?

A: The Company has accumulated nearly $30 million in solar rebate payments to customers under the requirements of the RES. Additionally, the Company has spent money in complying with all other aspects of the RES plan requirements. The Company has accumulated this in a deferred account as prescribed under the RES requirements and is requesting recovery in this case.

Q: Please describe KCP&L's RES recovery of this amount in this case.

A: The Company has included $7,664,452 in this case to reflect 1% of the overall revenue requirements to be recovered in an amortization. As described in the testimony of Ronald A. Klote, the Company had previously included an amortization of the prior balance in RES costs in the Company's last case (Vintage 1). The remaining balance of Vintage 1 plus all of the RES compliance costs incurred since then (Vintage 2) are in a deferred account. The unrecovered amount is not included in rate base.

Q: Why have you elected to include only 1% of the RES costs in the adjustment for recovery in rates?

A: On September 10, 2013, KCP&L filed a Case No. ET-2014-0071 for the Missouri territory served by KCP&L pursuant to the provisions of Section 393.1030.3 RSMo. On October 3, 2013, the parties entered into a Non-Unanimous Stipulation and Agreement. In the agreement, the parties agreed that KCP&L will not suspend payments of solar rebates in 2013 and beyond unless the solar rebate payments reach an aggregate level of

$36.5 million incurred subsequent to August 31, 2012. Other provisions of the Non-Unanimous Stipulation and Agreement[2] provided for:

A. Parties would not oppose recovery of prudently incurred solar rebates and RES compliance costs in future rate cases, RESRAM cases, or other proceedings in which recovery of these costs are considered by the Commission.

B. KCP&L shall include monthly carrying costs for prudently incurred cumulative unrecovered RES compliance costs from the period that the costs were incurred to the period that the costs are recovered.

C. KCP&L agrees that any cost recovery in future general rate proceedings or RESRAM proceedings will be consistent with 4 CSR 240-20.100(6), and that any recovery of RES compliance costs related to solar rebate payments will not exceed one percent (1%) of the Commission-determined annual revenue requirement in the proceeding.

D. GMO and KCP&L and their affiliates agree to retain all documents pertaining to solar rebate payments so the documents will be available for use in future ratemaking proceedings that address possible recovery of expenditures.

KCP&L expects to be at $36.5 million aggregate level in applications for installation of solar electric systems. The accumulation of solar rebates, RECs, S-RECs and costs of compliance in account 182, including carrying costs is expected to be $39.6 million.

[2] Report and Order, Exhibit A, starting at p. 3, Case No. ET-2014-0071 (Oct. 30, 2013).

IX. PRE-MEEIA COST RECOVERY/PRE-MEEIA OPT-OUT

Q: Please outline the timeframe of KCP&L's request relating to the pre-MEEIA cost recovery.

A: KCP&L filed its MEEIA application on January 7, 2014, and received Commission approval on June 5, 2014 for programs to become effective July 6, 2014. KCP&L has been offering demand-side management programs prior to MEEIA since 2005. The following table shows the proposed adjusted annual amortization amount being requested in this case for all pre-MEEIA vintages.

Vintage / Case Number	Pre-MEEIA Balance
Vintage 1 (EO-2005-0329)	$ 319,555
Vintage 2 (ER-2007-0291)	1,046,792
Vintage 3 (ER-2009-0089)	2,682,003
Vintage 4 (ER-2010-0355)	11,978,391
Vintage 5 (ER-2012-0174)	8,596,427
Vintage 6 (ER-2014-0370	20,390,597
Unamortized Deferred Balance at August 31, 2015	$45,013,765
Years Amortization	11
Annual Amortization Amount	$ 4,092,160
Adjustment	($1,896,493)

Q: Prior to the approval of KCP&L's MEEIA Rider mechanism, what additional pre-MEEIA expenditures are being included for recovery in this case?

A: Since the August 2012 true-up in KCP&L's last rate case, Case No. ER-2012-0174, KCP&L has incurred $20,390,597 in additional EE/DR expenditures including carrying costs from September 2012 to April 2015.

Q: Is KCP&L requesting a change in the amortization period for any of the referenced vintages?

A: Yes. The Company is requesting each vintage be amortized over 11 years.

Q: Why was this amortization period chosen?

A: This amortization period was selected because it is equivalent to the weighted average measure life of the as filed Missouri Energy Efficiency Investment Act ("MEEIA") programs in Case No. EO-2014-0095.

Q: **How was this weighted average measure life calculated?**

A: First, the average measure life for each of the MEEIA programs were drawn from the MEEIA programs study results. Then the average program measure lives were weighted by the budgeted dollars for each program which were obtained from Appendix A of the MEEIA filing in Case No. EO-2014-0095.

Q: Why was this methodology chosen?

A: The method was chosen to reflect recovery of the current unrecovered balance over the anticipated life of the programs. This proposal attempts to treat the unrecovered balance like an investment which is an offset to either building capacity or purchasing capacity. All of the evaluations that have gone into the development of the pre-MEEIA programs were based on the anticipated savings over the lifetime of the programs. Therefore, it made sense in this proceeding to recover the unrecovered balance over the anticipated remaining life of the programs.

Q: Please explain what KCP&L has included in this case for pre-MEEIA cost recovery

A: Summing the unamortized deferred balance at August 31, 2015 and then dividing by 11 years results in the new proposed amortization level as illustrated in the chart above. Additionally, consistent with prior treatment received in past rate cases, the Company has reflected the unamortized deferred balance in rate base, as discussed in the direct testimony of Company witness Ronald A. Klote.

Q: Please explain the details of KCP&L's request for pre-MEEIA opt-out cost recovery.

A: KCP&L is requesting this pursuant to the Non-Unanimous Stipulation and Agreement entered into in Case No. EO-2014-0029 dated September 23, 2013. In summary, the Non-Unanimous Stipulation and Agreement provides that KCP&L will file agreed-upon revised rate schedules that will include a pre-MEEIA energy efficiency charge ($ per kWh) that qualified opt-out customers can choose to avoid using the opt-out procedures specified in Commission Rule 4 CSR 240-20.094(6).

Q: Has KCP&L filed the referenced revised rate schedules?

A: Yes. The revised rate schedules were filed in KCP&L's MEEIA filing discussed earlier. As discussed in the Non-Unanimous Stipulation and Agreement, a pre-MEEIA energy efficiency charge for qualified opt-out customers will be recalculated and will be included in appropriate rate schedules in KCP&L's next general rate case, including all unamortized energy efficiency costs incurred since 2005 to the end of the test year in such rate case. Company has recalculated the pre-MEEIA rate resulting in a rate of

$0.00089/kWh. The calculation of the rate is included in the supporting workpapers filed in this case.

Q: What is the proposed treatment that KCP&L is requesting for the pre-MEEIA opt-out expenditures incurred to date?

A: The pre-MEEIA opt-out credits to customers have been accumulated in a deferred regulatory asset account and the Company proposes to amortize these amounts over three years. This adjustment is discussed further in the direct testimony of Company witness Ronald A. Klote.

X. DEPRECIATION STUDY REQUIREMENTS

Q: Has the Company performed a depreciation study in this proceeding?

A: Yes. A depreciation study has been performed for this case and is found in the Direct Testimony of John Spanos. The results of the study include the establishment of new depreciation rates as included in the Company's cost of service supported in the testimony of Ronald A. Klote.

XI. CUSTOMER PROGRAMS

Q: What is the purpose of this section of your testimony?

A: I will provide a status of the current Economic Relief Pilot Program ("ERPP") and the Company's proposal in this case to increase the program. As part of the *Non-Unanimous Stipulation and Agreement* ("Agreement"), Missouri Public Service Commission ("MPSC"), Docket No. ER-2009-0089, the Company agreed to implement the ERPP, providing an opportunity to ease the financial hardship experienced by some of our customers by providing a fixed credit to customers eligible under the terms of the pilot.

I will also offer testimony regarding KCP&L's Connections Program, giving customers access to resources that can make their life easier in a difficult economic environment. The program includes products and services to help customers save energy and money; a range of payment options; and ways to connect to assistance programs in the community.

<u>Economic Relief Pilot Program</u>

Q: Let us begin with the ERPP. Please provide a brief history of the ERPP.

A: The Company was looking for a way to help lower income customers keep their accounts current. Working with Staff, Office of Public Counsel, and the Customer Program Advisory Group ("CPAG")—a representative group of Missouri stakeholders that hold regular meetings to discuss customer related issues—the Company proposed a pilot program, the ERPP, designed to deliver energy affordability benefits to KCP&L's qualifying low-income residential customers. The ERPP delivers up to a fifty dollar per month "fixed credit" to low-income customers—improving energy affordability. As set forth in the *Agreement*, the ERPP is to provide up to one thousand participants, with fifty percent of the costs of the program deferred until KCP&L's next rate case. In that case, the deferred amount was authorized to be amortized over a three-year period. That amortization has been removed from the test year as the deferral will be fully amortized by the time new rates go into effect in this case.

Q: Is KCP&L seeking recovery of the current ERPP costs in this case?

A: Yes, the Company is seeking to recover the costs of the continuing ERPP. In adjustment CS-44, the Company has removed the amortization of the deferred cost for the pilot program. In addition, the Company has increased the expected spend for the ongoing program as it intends to increase this program to 1,500 total eligible participants in any given month.

Q: Has the program been successful?

A: Yes, between January 2013 and September 2014, the average number of monthly participants has averaged 969. During the same period, 20,355 customer bills have received an ERPP credit.

Q: How is the Company proposing to modify the ERPP in this case?

A: The Company is proposing to double the amount of available funds for the ERPP. Currently, the Company funds the program through shareholder dollars at $315,000 and rate payers fund the program at $315,000 making $630,000 available to help low to moderate-income customers with their bills. The modification proposed would set the Company's shareholder funding at $630,000 and the ratepayer funding at $630,000 making the total funding available $1,260,000. In order to make the funds more widely available, the Company is proposing to raise the current limit of 1,000 customer participants to 1,500 and increase the available monthly bill credit from $50 to $65.

Q: Why is the Company making this proposal?

A: The Company recognizes the challenge increasing electric rates places on its low to moderate-income customers, and believes the ERPP provides needed assistance to those customers. As discussed in the rate design section of my testimony, the rate design requested by the Company in this case includes changing the Residential customer charge from $9.00 to $25.00. Increasing the ERPP maximum bill credit to $65 from the current $50 is intended to help offset the increased customer charge for those customers in need. Additionally, the Company believes the ERPP has been successful. It is currently administered by the Salvation Army and there is often a waiting list of customers when the program is fully subscribed. The Company spoke with the Salvation Army and based on their input believes the program could be expanded to reach an additional 500 customers per month.

Q: Is the Company requesting any other change to the ERPP?

A: Yes, currently unused funds are to be used to offset demand-side management ("DSM") programs. The Company recently received approval to offer its DSM programs under the Commission's MEEIA rule provisions and believes it is more appropriate to use these funds to directly assist customers in need. Rather than using any unused funds to offset DSM, the Company is proposing to use unspent ERPP dollars to fund its assistance program currently known as Dollar-Aide. This program helps families pay their heating, cooling and water bills during financially pressing times and is administered by the Mid America Assistance Coalition.

Connections Program

Q: The Company is requesting funding for a communications program, (i.e. "Connections"), intended to help customers and educate them regarding payment assistance and options including the ERPP program. Please describe the Connections program.

A: The Connections program was created in response to observed challenges to our customers' ability to keep their accounts current because of a challenging economic climate. Utility assistance is available through various resources, including KCP&L. However, we found that many customers aren't aware of payment assistance and options available to them and wouldn't think to contact KCP&L if they were falling behind on their bills. Assistance information historically had been available on KCP&L's website and was communicated in newsletters and bill inserts. It was determined that additional proactive strategies were needed in order to reach customers and communicate effectively. The Connections program was created to help customers address payment needs, manage energy usage and access community resources. Today, there is still a need to communicate our Connections program to customers. As of October 1, 2014, for example, more than 20% of residential KCP&L accounts have past-due balances.

Q: What strategies do you use to communicate about Connections with customers?

A: We focus on mass communications strategies to reach all residential customers as well as more targeted strategies that are intended to reach specific demographic groups. Our customer insights indicate that while more customers than ever have fallen behind and are struggling to make ends meet, there are segments of our customer base who are struggling more than others. As a result, we have developed targeted strategies to reach those segments.

Our mass and targeted communications strategies include Advertising, Media Outreach, Digital Communications, Energy Resource Fairs, Employee Ambassadors and in-bound Call Center Support.

Q: How did you use Advertising to support the Connections program?

A: In order to reach the broadest audience possible, advertising is needed to support Connections and inform customers of the options available to them. We utilize broadcast, print and digital advertising mediums to connect with customers. Because minorities have a higher percentage of assistance need, we printed materials in multiple languages and focused much of our advertising spend with publications serving those populations.

Q: Why was Media Relations a strategy you used to promote Connections?

A: Our customer research indicates that our customers say the news media is a primary way they get information about KCP&L. Therefore, media relations is a key component of our Connections communications plan. We secured coverage with print, radio and TV stations, as well as local community blogs. We also promoted our Energy Resource Fairs, ERPP and other unique and timely Connections items via the media.

Q: You mentioned Energy Resource Fairs. Please explain.

A: We wanted to connect with customers on a personal level, face-to-face level. Through the Energy Resource Fairs, we have personally met with several thousand customers around our service territory. Each fair lasted several hours and customers could meet with KCP&L employees equipped to answer questions, set up payment arrangements and provide referrals to local resources, including the Salvation Army, United Way 2-1-1 and the Low-Income Home Energy Assistance Program. We have held the fairs various days of the week and times of day to accommodate our customers. The Community Relations department was instrumental in the fairs' success because each community manager set up and facilitated fairs in the community for which they are responsible. They were able to spread the word in a grassroots effort encouraging attendance and we also supported the promotion efforts via advertising and direct communications channels. We also asked our employees to promote the Connections program and serve as KCP&L ambassadors in their communities. This resulted in additional Energy Resource Fairs than were previously planned due to community interest.

Q: How did you partner with community agencies to implement the Connections program?

A: KCP&L saw an opportunity to partner with other community stakeholders, such as KCMO Weatherization initiative, Community Services, Inc., The Salvation Army, and United Way 2-1-1. These partnerships expanded the scope of available community resources available to customers, including information about applying for funding assistance and home weatherization. KCP&L promoted the assistance agencies in our communications material and invited the agencies to participate in our Connections Energy Resource Fairs. This extended our reach in the community. We provided collateral material the agencies for their use with customers year-round and they commented that the rebrand of Connections really breathed new life into the programs and shed new light on already available assistance. We also found that partnering with local assistance agencies, schools and churches resulted in a greater turnout because those organizations are trusted in their communities and already serve as resources for information and assistance.

Q: How did you educate your Call Center staff about the program?

A: KCP&L provided training to its customer service representatives so they were educated and able to help customers calling about Connections. In addition, the Company publicized a 1-800 number that was unique to the program on all marketing materials. We had dedicated call center representatives assigned to staff the 1-800 number in order to respond to customer inquiries and track which marketing tactics were most effective.

Q: Is KCP&L seeking recovery of the Connections program costs in this case?

A: Yes. Please see the Direct Testimony of KCP&L witness Ronald A Klote, Schedule RAK-4, adjustment CS-90.

XII. ELECTRIC CLASS COST OF SERVICE

Q: Has the Company performed an electric Class Cost of Service ("CCOS") study for this case?

A: Yes, the Company performed a CCOS study for this case. A summary of the results of the Company's CCOS study is attached and marked as Schedule TMR-7.

Q: Was the study prepared by you or under your direct supervision?

A: Yes, it was.

Q: Has the Company filed a CCOS in previous rate cases?

A: Yes. In all of the rate cases filed since 2005, the Company has filed a CCOS study.

Q: What is the purpose of the CCOS study?

A: The purpose of the CCOS study is to directly assign or allocate each relevant component of cost on an appropriate basis in order determine the contribution that each customer class makes toward the Company's overall rate of return. The CCOS analysis strives to attribute costs in relationship to the cost-causing factors of demand, energy and customers.

Q: Would the CCOS study serve as the basis for the determination of increasing or decreasing overall revenue levels for KCP&L?

A: No. Determination of the revenue requirement requested in this case is accomplished using the jurisdictional model sponsored by Company witness Ronald A. Klote. The

CCOS model uses the information from the jurisdictional model as an input for the primary purpose of exploring the distribution of costs to the respective classes.

Q: What classes are used as a basis for this CCOS study?

A: The classes the Company used in its analysis are Residential, General Service – Small, General Service – Medium, General Service – Large, Large Power Service, and Total Lighting. Additionally, the study includes details at the rate classification level, expressed by season.

Q: Do these classes conform to the current electric rate tariffs?

A: Generally, they do. The Residential class has several rate classifications available to it that include general use, one-meter general use and heat, and a two-meter rate with general use on one meter and a separate meter for space heating. The Small General Service, Medium General Service and Large General Service classes also have general usage rates and all electric rates, plus they can be specific to the voltage level at which the customer receives service. The Large Power Service class is distinguished by the specific voltage at which the customer receives service. In total, the Company has five classes of service (plus Lighting), but has approximately 68 rates to meet the specific needs of the customer and reporting and billing requirements.

Q: What test year was used for the CCOS study?

A: The study is based on a historical test year of the 12 months ending March 31, 2014, with known and measurable changes projected through April 30, 2015.

Q: What general categories of cost were examined and considered in the development of the CCOS study?

A: An analysis was made of all elements of cost as defined by the FERC Uniform System of Accounts, including investment (rate base) and expense (cost of service) for the purpose of allocating these items to the customer classes. To achieve this allocation we begin by functionalizing and classifying costs.

Q: Please explain what you mean.

A: In order to make the appropriate assignment of costs to the appropriate class of customer, it is necessary to first group the costs according to their function. The functions used in the CCOS study were production, transmission, distribution, and other costs. The next step was to classify the costs. Costs are classified as customer-related, energy-related, or demand-related.

Q: What do you mean by customer-related, energy-related and demand-related?

A: Customer-related costs are those costs necessary to provide electric service to the customer independent of any usage by the customer. Some examples of these costs include meter reading, customer accounting, billing and some investment in plant equipment such as the meter, service line and other local distribution facilities necessary to make service available. Portions of the distribution facility are separated between the customer costs and the demand costs.

Energy-related costs are directly related to the generation and consumption of energy and consist of such things as fuel and purchased power and certain transmission costs.

Demand-related costs relate to the investment and expenses associated with the Company's facilities necessary to supply the customer's full load requirements throughout the year. The majority of demand-related costs consist of generation, transmission plant and the non-customer portion of distribution plant.

Q: **After the above classification of plant investment and operating costs into customer- energy- and demand-related components, what was the next step in the CCOS study?**

A: The next step was to allocate each of the three categories of cost to each customer class utilizing allocation factors appropriate for each of the above categories of cost.

Q: **How are the allocation factors generally determined?**

A: Costs are evaluated to determine the cause driving the cost to be incurred and to establish an allocation method that best distributes the cost based on that causation. Customer-related costs are generally allocated on the basis of the number of customers within each class. Data for the development of the customer-related allocation factors came from Company billing and accounting records. Some of the customer-related accounts were allocated based on a weighted number of customers to reflect the weighting associated with serving those customers.

Energy-related allocation factors were derived on the basis of each customer classes' respective energy (kilowatt hour) requirements. Kilowatt-hour sales to each customer class were available from Company records. The sales data were adjusted to reflect normal weather, system losses and unaccounted for, in order to assign the Company's total system output.

Q: **How are class demand allocation factors generally determined?**

A: The data necessary to develop class demand allocation factors (production and transmission) were derived from the Company's load research data. Such data consisted of the hour-by-hour use of electricity by each customer class throughout the study period.

Q: **Was KCP&L's load research data used to develop any other allocators?**

A: Yes, it was used to develop distribution plant allocators based on customer's non-coincident loads within each class.

Q: **Are any costs assigned directly to classes?**

A: Yes. In those instances where the costs are clearly attributable to a specific class, they are directly assigned to that class.

Q: **What method do you propose to allocate production plant?**

A: Production plant is the single, largest component cost to allocate to the classes within the study. As such, the production allocator has the most impact on the outcome of the CCOS study. The Company reviewed industry data, NARUC materials, and information available within the public domain, including the National Association of Regulatory Utility Commissioners' "Electric Utility Cost Allocation Manual" published in January 1992. The Company did an informal survey performed by the Edison Electric Institute on plant allocation methods. Finally, we looked at testimony from Missouri and Kansas rate proceedings, exploring the positions offered by parties on the topic. The evaluation considered the three main categories of production allocation defined in the NARUC materials, Peak Demand, Energy Weighted, and Time Differentiated methods. After consideration of all allocation theories and ensuring that the selected method aligned with the principles of reflecting actual planning and operating characteristics, cost causation, recognize broad set of customer class characteristics and their usage, and produce stable results on a year to year basis, the Company selected utilization of the Energy Weighted approach, specifically the Average & Peak Production Plant Allocation method. An Energy Weighted approach was viewed to be cost effective, balanced with its incorporation of energy, and less subjective than other methods. Utilization of the Average & Peak method is an energy-weighted method of production plant allocation that gives classes recognition for both usage and contribution to peak load.

Q: **Has this allocation method been proposed before?**

A: Yes. KCP&L has utilized the Average & Peak Method in prior rate cases including ER-2006-0314 filed in 2006. In that same case, Commission Staff also proposed the Average & Peak method, although with a different "peak" determinate.

Q: **How were the fuel costs associated with the production plant allocated in the CCOS study?**

A: Fuel costs were allocated using a seasonal, monthly kWh allocator. Based on monthly fuel costs from the Company for the twelve months ended March 30, 2014, each month's fuel costs was allocated to each customer class's corresponding calendar month kWh sales adjusted for losses. These allocated results were summed seasonally, by rate and major customer class to identify a proxy fuel allocator which was then used to allocate the actual fuel costs shown in the cost study.

Q: **How were the off system sales margins that KCP&L receives from its external sales of energy allocated?**

A: They were allocated using the Energy allocator.

Q: What method did you use to allocate transmission plant costs?

A: Transmission plant costs are allocated using a 12 CP average demand factor.

Q: What method did you use to allocate Distribution Plant?

A: Distribution plant was allocated using a non-coincident peak demand allocator derived based on the use of non-coincident peak class demands for Primary Plant in Accounts 360 through Account 367. Also, Accounts 364, 365, 366 and 367 included methods to recognize primary and secondary voltage cost separation.

Q: What method did you use to allocate Line Transformers and secondary plant?

A: Line Transformers and secondary plant costs was allocated to customers receiving secondary service based on the weighted average of the diversified class demands (NCP) and undiversified individual customer maximum demands

Q: What method did you use to allocate Services?

A: Since we consider services customer-related, these costs were allocated based on the customers total undiversified maximum customer demands.

Q: What method did you use to allocate Meters?

A: Meter costs, recorded to Account 370, are also customer-related and were allocated using an assignment of all meters and metering devices to customer classes.

Q: Did you include any other rate base elements in the study?

A: Yes, multiple rate base elements have been included. The following details their allocation:

- Additions to net plant included cash working capital, materials and supplies, prepayments, fuel inventory, and various regulatory assets.

- The cash working capital component of rate base was developed and allocated on related expenses or plant in the cost of service study.
- Materials and supplies were allocated using plant allocation factors.
- Prepayment items were allocated using total plant, customers, and demand allocation factors.
- Fuel inventory was allocated on energy.
- The regulatory assets were allocated on labor, energy, or demand allocation factors depending on the costs tracked.
- The accumulated deferred taxes were allocated on total plant.
- The deferred gain on SO_2 emissions allowance and the deferred gain (loss) emission allowances were allocated on an energy allocation factor.
- Customer advances for construction were allocated on total distribution plant.
- Customer deposits were developed using the data analysis by customer group available from the Company.

Q: What revenues did you use for this study?

A: The class and rate revenues were developed under my supervision and were discussed earlier in this testimony. Other sources of revenues such as Miscellaneous Revenues were allocated consistent with the revenue source.

Q: How were Operation and Maintenance Expenses allocated?

A: Operations and Maintenance (O&M) Expenses were allocated using various methods dependent of the cost causation. O&M for production, transmission and distribution plant were allocated to customer classes following plant. Customer Accounts Expenses, Customer Services and Information Expenses, Sales Expenses, and Administrative and

General Expenses were allocated based on the results of individual allocation studies. Administrative & General expenses were primarily allocated on the labor allocator with the exception of Account 930.1, General Advertising, which was allocated based on the number of customers and Account 928, Regulatory Commission expenses, which was primarily allocated to classes on revenues at the uniform claimed rate of return.

Q: **What is the next step after the allocations are applied?**

A: The next step is to determine the relative return on rate base for each of the classes in the study. The ratio of class revenues less expenses (net operating income) divided by class rate base will indicate the rate of return being earned by the Company that is attributable to a particular class. It is necessary to keep in mind that this is a snapshot in time. The results of the CCOS study will most likely vary over time. The results of the study will also vary if you apply different allocation factors to the study. By applying different methods to the allocation process, you can change the outcome of the CCOS study.

Q: **What were the results of the CCOS study?**

A: The jurisdictional rate of return was calculated to be 5.0%. Individual classes' rates of return at current rates vary, and based on the current costs, are shown in the following table.

Residential	Small General Service	Medium General Service	Large General Service	Large Power Service	Other Lighting
3.7%	7.1%	6.3%	6.6%	4.2%	12.2%

Q: **If rates were changed so that KCP&L earned the same rate of return from each customer class, how much would each class's rates need to change?**

A: To achieve the jurisdictional revenue increase of 15.75%, the classes should be adjusted by the percentages in the table below.

Residential	Small General Service	Medium General Service	Large General Service	Large Power Service	Other Lighting
24.7%	3.8%	8.4%	6.7%	20.8%	-13.2%

Q: What general conclusion can be made from these results?

A: The results of the CCOS study show that each class of customers recovers the cost of service to that class and provides a return on investment.

Q: In addition to the class results, was the study used to provide any additional information?

A: Yes, another element of the study was to explore costs at the rate level and the season level. This data provides additional information to aid the Company in preparing its rate design.

Q: What were the results at the rate and season level?

A: Adding these multiple levels of detail increase the amount of data so it is best to present the results in the form of tables. Schedule TMR-8 is attached to provide that information. Review of the results show that the summer and winter rates for each class provides recovery of the cost of service and a return on the investment. The CCOS study demonstrates that rates charged during the winter in nearly every case, provide a higher contribution to the average return on investment than the summer rates.

Q: Are you proposing any changes to the class revenues based on the results of the study?

A: Utilizing the results from the study prepared based on the Average & Peak production allocation; the Company has identified four proposals:

- No class revenue shifts based on the rate of return results,

- Increase the residential customer charge to include customer costs and local distribution facility costs.
- Adjustment of the residential summer and winter rates.

Application of these proposals to the electric rates are discussed further in the rate design section of this testimony.

XIII. ELECTRIC RATE DESIGN

Q: Are you sponsoring the electric tariffs filed in this case?

A: Yes, I am.

Q: Please summarize the proposed rate design recommendation for the electric tariffs and any additional proposed changes to the tariffs?

A: The Company is requesting an increase in rates of $120.9 million (15.75%). The Company is proposing that the requested increase be applied to the classes on an equal percentage basis.

Within the classes the Company is proposing a number of changes. Those changes include:

Residential

- Better balance the fixed/variable relationship within the residential rates by moving certain costs currently recovered from the energy rates to the customer charges. The customer charges are designed to recover customer and local distribution costs.
- Additionally, the Company proposes to make some shift from the summer and winter, consistent with the CCOS study. The proposed rate design shifts pricing from the winter season to the summer season.

- Clean up references to unused programs (Residential Conservation and AC Load Control)
- Realign Residential – Other Use rate to be better positioned between residential and small general use rates.

Commercial and Industrial (C&I)

- Rate designs is applied on an equal percentage basis across all classes and bill elements.
- Made several corrections to misaligned rate elements. The Company identified a few rate elements associated with the All-Electric rates, priced higher than the same element within the General Use rate. The Company is proposing to correct the pricing of these elements by setting the rates equal to the General Use rates.

Special Rates (Such as Two Part-Time of Use, Special Interruptible, Real Time Pricing, Special Contracts – Customer Specific, and Standby or Breakdown Service)

- Propose freezing or eliminating special rates not used or no longer functional.
- Rate design is applied on an equal percentage basis across all bill elements.

Lighting

- Clean up obsolete rates
- In support of the proposed Energy Cost Adjustment, add kWh usage information to the tariffs.
- Rate designs is applied on an equal percentage basis across all bill elements.

Rules & Regulations

- Clean up obsolete sections

- Propose changes will better align the rules & regulations with current costs or planned business practices. Changes that will continue to align the operations of all parts of the Company.

The specific, proposed changes to rates may be found in Schedule TMR-9 and the proposed changes to the tariff sheets can be found in Schedule TMR-10.

Q: How did the company go about formulating this rate design proposal?

A: To begin, we reviewed a set of established critical considerations that would guide the rate design effort. These considerations are

- Provide Revenue Stability and Risk Mitigation
- Attempt to Implement Cost-Based Rates
- Minimize Customer Dissatisfaction and Continue Practice of Gradualism
- Simplify Rate Structures and Construct Consistent Rate Structures
- Consider Technology Advantages and Limitations
- Consider impact to Energy Efficiency and Demand Response Programs

These principals have been refined through multiple rate cases and have a fundamental relationship with the principles espoused by Dr. James C. Bonbright.[3]

Q: Please describe the current state of the Company's rate?

A: The existing rate structures are generally good, meeting many of the critical considerations noted previously. Particularly, the multi-part rate structure of the Commercial and Industrial rates provides good opportunity to price the electric product and gives these customers significant information about their usage and the impact on

[3] Bonbright, J.C. Principles of Public Utility Rates. New York, NY: Columbia University Press. 1961. Pages 290 through 294.

their monthly bill. Further, the review revealed that some of the special rates currently offered by KCP&L are not working as intended and have little customer adoption.

One concern identified was with the way our rates are aligned with costs. The current rates have a large amount of costs that are fixed and do not fluctuate with energy usage that is being recovered through the energy rates. Estimates note that about 80% of our costs could be considered fixed or unrelated to volumetric consumption. By contrast, our current residential rates are configured such that approximately 91% of our revenues are collected through "per kWh" or variable rates. The means of revenue recovery is nearly an exact opposite to the way the costs are incurred. Our propose residential rate design will result in shifting revenues from the energy rates to the customer charge, and will result in 78% of the revenues being collected from the variable charges.

Q: Please describe why it is appropriate to align costs with the cause of the cost?

A: At its core, cost causation alignment is used to keep rates equitable and avoid distortion within the rate. When cost elements are out of alignment, it is likely that costs will not be properly recovered through the rate. For example, if the rate collects significant proportions of revenue through the variable charge, reductions in usage will cause an immediate under-recovery for that rate for the utility. Over time within a customer class, when some customers reduce usage and others do not, the customer with the higher usage ends up covering the fixed costs for the customer that avoided them, despite the fact that both customers benefited from the infrastructure investment that fixed charge is designed to recover.

Price distortion is the other result of a misaligned rate. Distortion occurs when the price does not reflect the cost and results in an incorrect price signal being sent to the customer. In the example where a rate collects significant proportions of revenue through the variable charge, a customer might perceive that the "per kWh" value of energy is higher than it truly is. This is highlighted when you compare the energy rate paid by Residential customers versus Commercial or Industrial (C&I) customers. Comparison of the rates paid generally will show that the per kWh charge paid by a Residential customer is significantly higher than that paid by a C&I customer. A primary contributor to that differential is the fact that many fixed costs, normally recovered through customer, facility, or demand charges applied to the C&I customer are combined into the Residential energy price.

Q: How do rates get out of alignment?

A: Misalignment is largely the result of limited rate components combined with other policy considerations overriding alignment concerns. For Residential customers, there are only two rate components in the structure, the customer charge and the energy charge. All revenue recovery is accomplished through the two. By contrast, the Commercial & Industrial rates have up to four components, the customer charge, facility charge, demand charge, and energy charge. In this design, the customer, facility, and demand charges carry additional portions of the fixed charge. Under the limited components of the residential structure, the choice is between the customer charge or the energy charge. It is in this decision where policy consideration makes its impact. There has been a long tradition of relatively low customer charges, as a result, nearly all of the fixed costs have been included in the energy charge. This decision has been largely reinforced by the perception that low-income customers are low usage customers, and that maintaining an artificially low customer charge provides "protection" for those customers.

During periods of continued load growth and periods where all customers share very similar usage characteristics, the electric utility and regulators would be indifferent and could accept the distorted pricing. Customers would also accept the distortion as it appeals to simple reason and generally represents a small portion of the bill paid by the average customer. It is when the growth subsides or when the characteristics of class usage change when the misalignment issue reveals itself.

Q: Please explain what you mean.

A: From the Company perspective, reductions in usage, driven by reduced customer growth, energy efficiency, or even customer self-generation, result in under recovery of revenues. Growth would have compensated or completely covered this shortfall in the past. With the accelerating deployment of initiatives that directly impact customer growth, it is becoming increasingly difficult for the Company to accept this risk of immediate under recovery. On the customer side, the problem with alignment can occur for multiple reasons but is most clearly shown through the implementation of distributed generation. When a customer deploys distributed generation at their location, they are often able to avoid most, if not all of their annual energy bill. The revenues originally received from that customer are now avoided due to distributed generation. In future rate cases, those costs are spread to the remaining customer usage and borne by customers without distributed generation.

Q: Does the Company proposal totally achieve proper alignment of fixed/variable costs alignment in rates?

A: No. If the rates were designed under a straight fixed variable model, we expect the customer charge would be much higher. Fixed costs associated with distribution, transmission and generation would be moved from the energy charge, increasing the residential customer charge to the neighborhood of $75 to $100 per month with the resulting energy charge less than $0.02 per kWh for all usage. The Company proposal is designed to improve the alignment but not to achieve straight fixed variable pricing.

Q: Should alignment of costs be the primary driver for the rate design?

A: Not necessarily. The Company recognizes the risk and the negative impact of a fully fixed/variable aligned rate. The Company supports a balanced rate design that achieves a reasonable move towards recovering the fixed costs in the customer charge. The seasonal elements would allow energy rates to reflect the generally higher cost of energy during the summer peak periods. For electric energy pricing, focusing on peak pricing and overall system load factor are the most appropriate ways to reduce cost and improve efficiency.

Q: In light of these concerns, why does this proposal make sense?

A: At its core, the current pricing is wrong. The significant imbalance within the price distorts the price of electricity, distorts the benefits of EE and DG, and exposes the Company to loss in revenue. The current price structure masks costs, giving the impression that the volumetric charge is completely avoidable without risk or harm. Currently, if you could reduce your usage far enough, you could nearly eliminate your electric bill. Absent a complete disconnection from the grid, this situation is unsustainable. There are significant amounts of assets and resources put in to place to ensure a customer has access to electric energy at need. Even customers with the most successful EE efforts or the best performing DG systems, rely on those assets and resources, receiving significant benefit from them. Ignoring that fact in the pricing will provide customers the false belief that they can be energy self-sufficient, leading to poor choices regarding their long-term energy use. The Company's proposal attempts to find a balance between the customer and the utility.

Q: Turning specifically to the proposed changes for the Residential class, what are the details of the proposal?

A: A number of changes have been proposed for the Residential class. The changes are intended to address most of the critical considerations identified earlier. The Company is proposing the following:

- The Company proposes setting the customer charge to $25 per month, a level that basically recovers customer and local distribution costs for this class of customers. These costs are representative of the primary fixed costs attributable to the customer, unrelated to the customer's energy usage. Additionally, summer energy rates were increased while winter energy rates were either held constant or reduced. This shifting helped reduce the overall impact of the change. Further, the proposal will not only help address fixed/valuable cost alignment, but will also help reinforce seasonal price differentials.
- Remove tariff references to the Residential Conservation Program and the Air Conditioner Load control program. Both are obsolete programs. The Residential Conservation Program was established by the Missouri Department of Natural Resources in response to the National Energy Conservation Policy Act of 1978. The program has been superseded by the Income eligible Weatherization Program. The Air Conditioner Program was established in July of 1988 to provide the Company

with a mechanism to reduce peak loads. Over time, this technology was removed from service and other programs deployed to effect changes to peak reduction.

- Revise the energy pricing of the Residential Other Use rate to better align it with the Residential and Small General Service rates. The Residential Other rate is intended to serve customers with loads that are residentially related but are not associated with a primary premise or home. For example, water well pumps, barns, machine sheds, garages, and workshops not connected to the customer dwelling.
- Freeze availability of the Residential TOU rate. The Residential TOU rate only has 38 customers and does not perform as it should. The Smart Grid TOU rates are currently scheduled to expire at the end of this year. Those customers will revert back to their generally available rate at that time.

Q: What is the impact of the Residential class proposal?

A: As noted previously, under the Company proposal the Residential class will experience an increase equal to the overall requested increase. Within the class, the Company is proposing various changes that will result in different increases for the different rate groups. To help clarify the impacts the following table details the impacts:

Rate Group	Description	Typical Impact (Impact to Ave. Customer in Group)
RESA	General Use	13.59%
RESB	One Meter Heating	12.79%
RESC	Two Meter Heating	12.82%
RTOU	Time of Use	17.11%
RES-Other	Other Use	22.51%

Q: Most of these impacts are below the class average increase. How is that possible?

A: The above table details the impacts to typical customers, those customers at the average for the rate group. Since part of the revenues have been shifted from the energy charge (variable portion) of the structure to the customer charge (fixed portion), customers with low usage will see an increase higher than average.

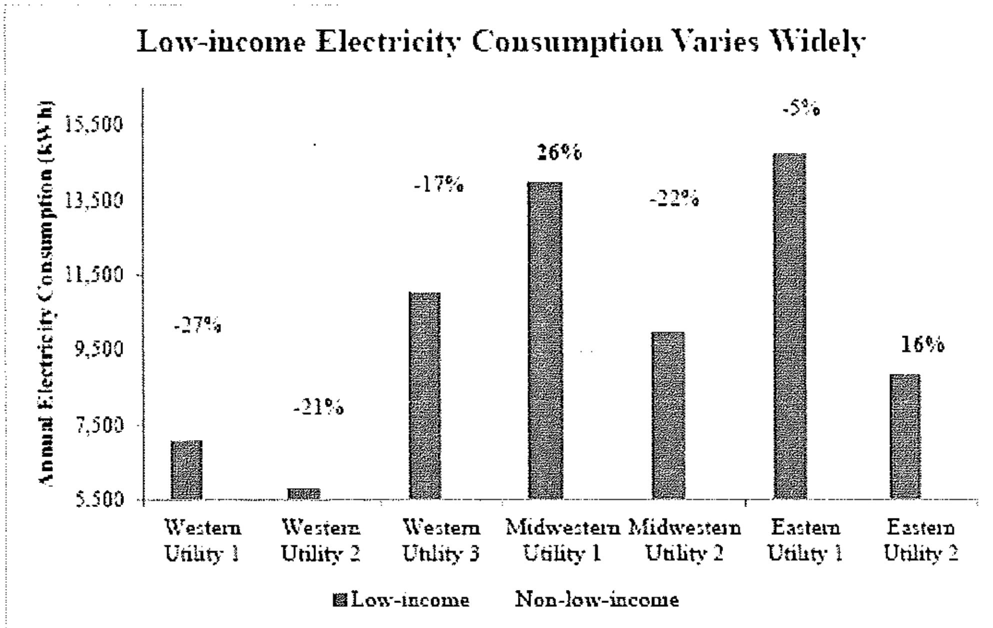
Q: What is the impact to those low use customers?

A: The extreme example would be a customer with no usage whatsoever. In that case, the customer would see their bill increase from $9.00 to $25.00. The increase would be $192 per year. Customers on the separately metered rates for space heating would see the charge for that extra meter increase from $2.05 to $5.00.

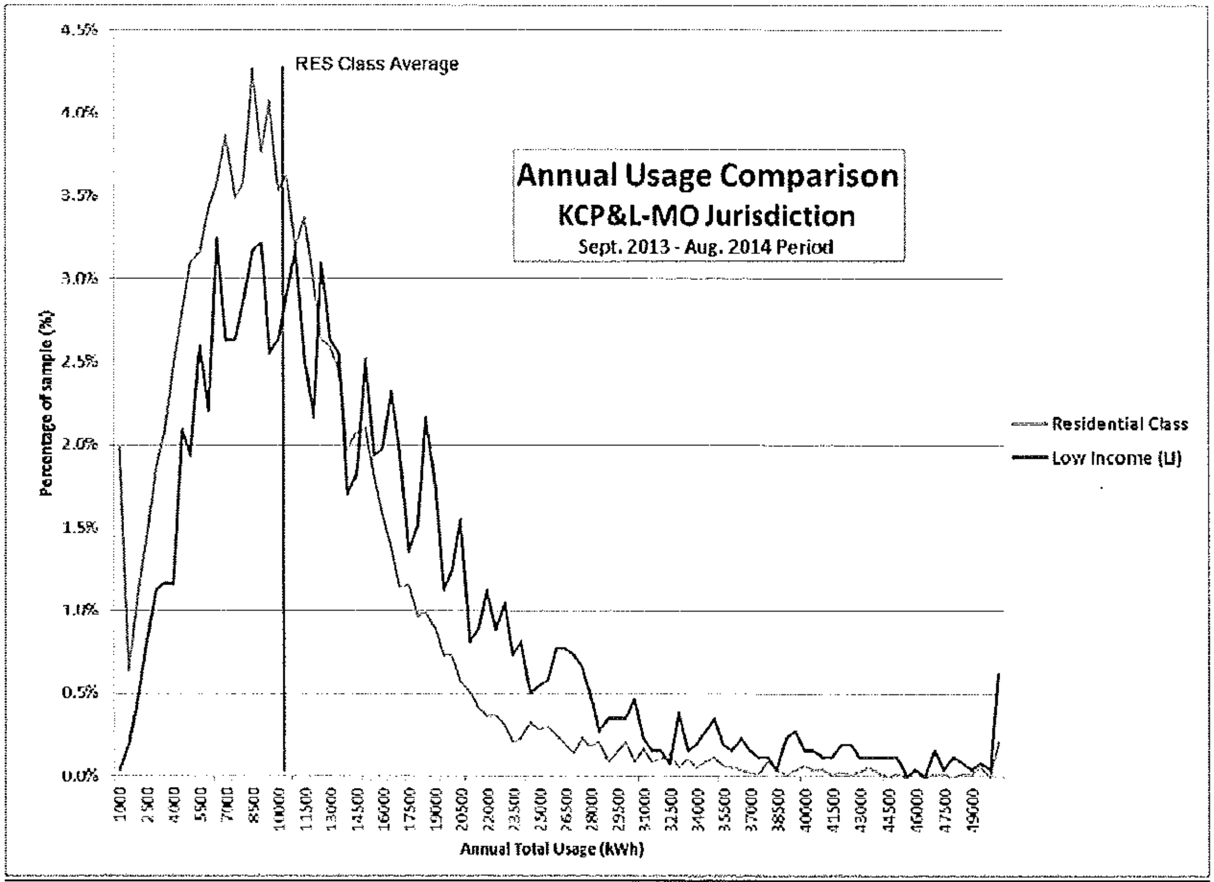
Q: Are low-usage customers the same as low-income customers?

A: No. According to our evaluation, low-income customers have usage levels similar to the residential class at large. One could easily think that there is a relationship between income and usage, expecting that low-income customers use lower amounts of energy. In exploring this question, we looked at industry sources and found little research on the topic. One source identified was a report prepared by Serj Berelson of Opower for the 2014 ACEEE Summer Study on Energy Efficiency in Buildings[4]. The following chart shows a varied relationship between low-income and non-low-income customers:

[4] Myths of Low-Income Energy Efficiency Programs: Implications for Outreach, Serj Berelson, Opower, 2014 ACEEE Summer Study on Energy Efficiency in Buildings



The Company then turned to its own data sources to explore the relationship we might find with our customers. Using data from the Company billing system, we compared annual usage from customers receiving Low Income Home Energy Assistance Program (LIHEAP) support, an established means to determine income levels, to a random sample of residential customers. The comparison yielded a similar pattern of consumption for both groups.



Although we believe this supports a position that low income does not automatically mean low usage, we acknowledge that there are low-income customers who will be impacted at a greater level than the typical customer.

Q: Has the Company included in this proposal anything to help address the impacts to low-income customers?

A: Yes. As noted previously in this testimony, the company is proposing to expand and modify the ERPP to address this potential increase in need. Additionally, we are proposing to redirect any unspent ERPP program funds to Dollar-Aide, another Company program designed to help customers pay their heating, cooling and water bills and avoid service loss. I believe these programs are perfectly suited to support low-income customers unable to benefit under the proposed rate design. If approved as proposed, the ERPP program alone will provide up to $780 per year.

Q: Now, concerning the Commercial and Industrial Rates, what are the details of the rate design proposal?

A: For the Small General Service, Medium General Service, Large General Service, and Large Power Service classes the Company is proposing these classes will receive an increase equal to the overall requested increase. Within the class, the Company is proposing to correct misaligned rate elements. During the case preparation, the Company identified a few rate elements associated with the All-Electric rates, priced higher than the same element within the General Use rate. The Company is proposing to correct the pricing of these elements by setting the rates equal to the General Use rates. These corrections will result in a slight deviation from the overall requested increase, but nothing considered material.

Q: Did the Company consider similar fixed/variable changes for the Commercial and Industrial (C&I) rates as were proposed for the Residential rates?

A: Yes. The misalignment described for the Residential class occurs in the C&I rates as well. However, there are greater risks to changing the C&I rates. By design, customers are free to move between the C&I rates as needed to find the best rate for their situation. Normally, customers would move through the rate classes as their energy needs grow. During a rate case, this flexibility can expose the Company to rate switching and lost revenues if the impact of a proposed rate design is not known. In this case, the Company considered changes to the fixed/variable pricing but was unable to confidently determine the rate switching impact. The Company decided to postpone changes of this type until the Company is better prepared to determine the impact.

Q: What is the Company proposing concerning its Lighting Rates?

A: The Company is proposing that the Lighting class receive an increase equal to the overall requested increase. Within the specific tariffs, the Company is proposing to eliminate parts of the lighting rates that are obsolete and no longer used. Additionally, in support of the proposed Energy Cost Adjustment, the Company is proposing to add monthly, kWh usage information to the lighting tariffs.

Q: What is the Company proposing concerning its Rules and Regulations?

A: The Company has reviewed its Rules and Regulations and identified a number of changes to propose in this case. In general, the Company is seeking to clean up the rules and regulations and propose changes to better align the rules & regulations with current costs or planned business practices. Specific details concerning the proposed changes are found in Schedule TMR-10.

Q: Are you proposing any additional tariff changes?

A: Yes as part of this filing the Company is proposing the following:

- Alternate Table of Contents – the Company would like to establish an alternate, topic based table of contents. It is our observation that the table of contents has grown, and in its current sheet number order, is difficult to find what is needed. The proposed alternate view will list the sheets topically, providing customers a second method to navigate the tariffs.

- Company Employee Merchandise & Equipment Purchase Program – the Company proposes to eliminate this program. The program is no longer offered and all of the associated loans have been repaid.
- Promotional Practice Variances – the single variance was associated with a customer that is no longer utilizing the end-use equipment associated with the variance. The Company proposes to eliminate this tariff as it is no longer needed.

Q: What revisions are being proposed at this time?

A: A number of changes are being proposed, most linked to format, presentation, and general clean-up. The following are the general changes proposed:

1. A new format is proposed for the KCP&L tariffs. The Company will propose a version similar to that used by KCP&L-Greater Missouri Operations Company.
2. Billing rate codes added to the respective rate tariff pages.
5. An additional, topic-based table of contents page added to supplement the existing sequential table of contents.
6. Incorrect items in the table of contents will be corrected.
7. Blank, reserved for future use "sub-pages" (48A, 48B, etc.) removed leaving only the primary blank pages (48).
8. Frozen or obsolete tariffs or tariff items (lighting sub-sections for example).
9. For an obsolete program defined through a tariff (such as sheet #3 Residential Conservation Service Program or sheet #4 Air Conditioner Load Control Rider) the Company will recommend the tariff be frozen.

Q: Does that conclude your testimony?

A: Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement A General Rate Increase for Electric Service	)))	Case No. ER-2014-0370

AFFIDAVIT OF TIM M. RUSH

STATE OF MISSOURI)
) ss
COUNTY OF JACKSON)

Tim M. Rush, being first duly sworn on his oath, states:

1. My name is Tim M. Rush. I work in Kansas City, Missouri, and I am employed by Kansas City Power & Light Company as Director, Regulatory Affairs.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Kansas City Power & Light Company consisting of Seventy-two (72) pages, having been prepared in written form for introduction into evidence in the above-captioned docket.

3. I have knowledge of the matters set forth therein. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded, including any attachments thereto, are true and accurate to the best of my knowledge, information and belief.

Tim M. Rush
Tim M. Rush

Subscribed and sworn before me this 30th day of October, 2014.

Nicole A. Wehry
Notary Public

My commission expires: Feb. 4 2015

NICOLE A. WEHRY
Notary Public - Notary Seal
State of Missouri
Commissioned for Jackson County
My Commission Expires: February 04, 2015
Commission Number: 11391200

SCHEDULE TMR-1

THIS DOCUMENT CONTAINS HIGHLY CONFIDENTIAL INFORMATION NOT AVAILABLE TO THE PUBLIC

Requirements to Establish a Fuel Adjustment Clause

4 CSR 240-3.161 (2):
When an electric utility files to establish a RAM as described in 4 CSR 240-20.090(2), the electric utility shall file the following supporting information as part of, or in addition to, its direct testimony:

(A) An example of the notice to be provided to customers as required by 4 CSR 240-20.090(2)(D):

See Schedule TMR-3, page 1.

(B) An example customer bill showing how the proposed RAM shall be separately identified on affected customers' bills in accordance with 4 CSR 240-20.090(8);

See Schedule TMR-3, pages 2-3.

(C) Proposed RAM rate schedules:

See Schedule TMR-4.

(D) A general description of the design and intended operation of the proposed RAM:

The design and intended operation of the Fuel Adjustment Clause (FAC) is consistent with the KCP&L-Greater Missouri Operations Company FAC approved in Rate Case No. ER-2012-0175. The change proposed in this filing is for the amounts contained in base rates as well as the addition of nuclear fuel costs and transmission costs/revenues in the clause. Some key features of the FAC include:

- The FAC factor is based upon historical differences between the cost of fuel, energy, and certain transmission costs and fees from SPP net of off-system sales revenue and transmission revenues built into base rates and the actual cost of these items as incurred during the two six-month accumulation periods.
- There is 100% recovery of the difference between these actual costs and the amounts built into base rates.
- Items considered in the FAC are variable non-labor generating plant fuel costs, purchased power energy and short-term capacity charges, emission allowance costs, transportation costs, hedging costs and transmission costs. These costs are offset by off system sales revenues, the revenues from the sale of renewable energy credits as well as transmission revenues. The Southwest Power Pool Integrated Marketplace (SPP) began in early 2014. As a result, generation is bid into the SPP market and retail load is purchased from the SPP market. This market transformation has led to the recommendation that 100% recovery of the FAC. Carrying costs are calculated monthly at the Company's short term debt rate.
- The under or over recovery will be accumulated for 6 months. The collection period for the accumulation is 12 months.

- The base amounts for the current tariff are $.01547 per kWh for KCP&L (MO).

(E) A complete explanation of how the proposed RAM is reasonably designed to provide the electric utility a sufficient opportunity to earn a fair return on equity:

The FAC is designed to recover all applicable costs on a going forward basis, so the Company's achieved ROE will not be changed, up or down, relative to its Commission-authorized ROE, due to decreases or increases in actual costs experienced by the Company when the FAC is in effect.

(F) A complete explanation of how the proposed FAC shall be trued-up to reflect over or under-collections, or the refundable portion of the proposed IEC shall be trued-up, on at least an annual basis:

Each month there is an accrual to reflect the over/under recovered current month FAC fuel costs in General Ledger Account 182380-Accrued Fuel Clause. The accrual calculation is Total FAC Actual Energy Costs less Base Energy Costs.

After the defined 6 month accumulation periods (October-March and April-September) a filing in accordance with 4 CSR 240-20.090(4) is made with the Missouri Public Service Commission requesting a new cost adjustment factor. The collection/return periods for these FAC factors are 12 month (July-June and January-December).

Activity in account 182380 is manually tracked by accumulation period and separately identifies the accrual recovery, interest and over/under recovery balance for each open accumulation period.

After the 12 month recovery period is complete, a true-up filing is made and any remaining over/under recovery identified is included as part of the next FAC filing.

(G) A complete description of how the proposed RAM is compatible with the requirement for prudence reviews:

4 CSR 240-20.090 sets forth the definitions, structure, operation, and procedures relevant to a Fuel Adjustment Clause. Section (7) is specific to prudence reviews, requiring a review no less frequently than at eighteen (18)-month intervals.

The Company agrees that prudence reviews should occur no less frequently than at 18 month intervals. This requirement is also in the FAC tariff.

It is anticipated that parties to any prudence review proceeding would apply the standard of determining whether decisions were prudent given the facts known at the time those decisions were made, as opposed to a "hindsight" review. If Staff or other parties believe that the evidence supports a prudence adjustment, they have the opportunity to bring that proposal to the Commission for an evidentiary hearing and decision.

(H) A complete explanation of all the costs that shall be considered for recovery under the proposed RAM and the specific account used for each cost item on the electric utility's books and records:

The Federal Energy Regulatory Commission (FERC) Code of Federal Regulations is the basis for the Company's accounting codes. Fuel used in the production of steam for the generation of electricity (Coal Plants) is included in FERC account 501. Allowances are included in FERC account 509. Fuel used in production of nuclear generation is included in FERC account 518. Fuel used in other power generation (Combustion Turbines) is included in FERC account 547. Purchased Power is in FERC account 555. Transmission of electricity by others is included in FERC account 565. Scheduling, system control and dispatch services are included in FERC account 561.4. Reliability planning and standards development services are included in FERC account 561.8. Market facilitation, monitoring and compliance services are included in FERC account 575.5. Regulatory commission expense for FERC is included in FERC account 928. Sales for resale are recorded in FERC account 447. Transmission Revenue from Others is recorded in FERC account 456.1. The following six digit Company accounts expanded with the usage of a resource code, representing native load (NL) and sales for resale (SFR), and are included in the FAC.

General Ledger Account/Resource	Expense
501000/6000	NL Bit Coal and Freight Costs (Variable)
501000/6005	NL PRB Coal and Freight Costs (Variable)
501000/6030	NL Tire Costs (Variable)
501000/6001	NL Bit Coal Inventory Adj.
501000/6006	NL PRB Coal Inventory Adj.
501000/6035	NL Biofuels
501020	NL Coal and Freight Costs (Variable)
501000/6002	NL Bit Coal Freeze & Dust Treatment
501000/6007	NL PRB Coal Freeze & Dust Treatment
501030	SFR Coal & Freight Costs
501000/6016	NL Oil Costs
501000/6018	NL Oil Inventory Adj.
501000/6020 - 6024	NL Gas
501000/6027	NL Gas Adjustments
501000/6017	NL Propane
501300	NL Additives
501400	NL Residuals Costs
501450	NL Residuals Costs
509000	Emission Allowances
509000	Renewable Energy Credits (Sale of RECs)
518000	NL Nuclear Fuel Expense
518100	NL Nuclear Pwr Fuel Expense Oil
518201	NL Nuclear Fuel Disposal Cost
547000/6016	NL Oil
547000/6020 - 6024	NL Gas Costs & Transportation (Variable)
547000/6027	NL Gas Adjustments

547000/6018	NL Oil Adjustments
547000/6026	Hedge Settlements
547020	NL Gas Costs & Transportation (Variable)
547030	SFR Gas Costs & Transportation (Variable)
555000, 555021	NL Purchased Power-Energy
555005	Purchased Power-Capacity (Short-term ONLY)
555030, 555031	SFR Purchased Power-Energy
561400	Trans OP LD Dispatch Control&Dispatch
561800	Trans OP LD Dispatch ReliabilityPlanningRTO
565000	Trans OP Trans of Elec by Others
565020	Trans OP Trans Res Load CHG
565027	Trans OP Trans by Other Demand
565030	SFR Transmission
575700	Trans OP MKT MON&COMP SER RTO
928000/Dept 415	Regulatory Commission Expense (FERC assessments)

General Ledger Account	Revenue
447002	Bulk Power Sales
447012	Wholesale Sales Capacity (Short-term ONLY)
447030	SFR Off-system Sales
456100	Revenue Trans Elect for Others

Accounts provided were known as of the time of this filing; however, they may be revised in the future as business needs arise.

(I) A complete explanation of all the revenues that shall be considered in the determination of the amount eligible for recovery under the proposed RAM and the specific account where each such revenue item is recorded on the electric utility's books and records:

FAC revenues are billed as a separate line item on a customer's bill and all FAC revenue is recorded in the following revenue accounts/resources to accurately track revenues and facilitate the review process. In addition, the CIS+ billing system tracks the FAC billed line item. FAC revenues are reported separately on CIS+ Revenue Reports.

General Ledger Account/Resource	Revenue
440001/5500	Residential Electric Revenue
442001, 442004, 442101/5500	Commercial Electric Revenue
442201-442202/5500	Industrial Firm Electric Revenue
444001-444002/5500	Sales Street Lighting

Billed FAC revenues are initially recorded as revenue (as shown above) when processed by CIS+. Accounting reverses the Billed FAC revenue exactly and offsets the Accrued Fuel Clause account (182380). The reclassification of the Billed FAC revenue is through a separate set of resource codes within the revenue accounts, as follows:

General Ledger Account/Resource	Revenue
440001/5525	Residential Electric Revenue FAC Rcvy
442001, 442101/5525	Commercial Electric Revenue FAC Rcvy
442202/5525	Industrial Firm Electric Revenue FAC Rcvy
444001-444002/5525	Sales Street Lighting FAC Rcvy

Current period over/under accrual FAC revenues are booked as defined above as Total FAC Actual Energy Costs less Base Energy Costs with the resulting accrual offset in General Ledger Account 182380, Accrued Fuel Clause. The over/under accrued FAC revenues is booked to a separate set of resource codes within the revenue accounts, as follows:

General Ledger Account/Resource	Revenue
440001/5520	Residential Electric Revenue FAC Unbilled
442001, 442101/5520	Commercial Electric Revenue FAC Unbilled
442202/5520	Industrial Firm Electric Rev FAC Unbilled
444001-444002/5520	Sales Street Lighting FAC Unbilled

This accounting process, and the information used to support the recording of these entries, creates a paper audit trail to enable the audit of the accounts.

(J) A complete explanation of any incentive features designed in the proposed RAM and the expected benefit and cost each feature is intended to produce for the electric utility's shareholders and customers:

The primary incentive for an effective FAC mechanism is the prudence review. Currently, the Commission has allowed utilities with an FAC to recover only 95% of the incremental costs above the fuel costs in base rates. This action is more of a disincentive and does not allow the utility an opportunity to recover its full costs associated with fuel and purchased power. Because the SPP Integrated Marketplace has been implemented, SPP members are now required to bid in generation resources and to buy retail load from the SPP market. The Company proposes to recover 100% of its FAC rather than 95%.

(K) A complete explanation of any rate volatility mitigation features in the proposed RAM:

The hedge program costs and benefits, as discussed in the Direct Testimony of Wm. Edward Blunk, can mitigate fuel price volatility. In addition, accumulating the FAC adjustment for a 6 month period with a corresponding 12 month revenue recovery period lessens rate volatility.

(L) A complete explanation of any feature designed into the proposed RAM or any existing electric utility policy, procedure, or practice that can be relied upon to ensure that only prudent costs shall be eligible for recovery under the proposed RAM:

The Company's FAC expenses are subject to periodic Prudence Reviews to ensure that only prudently-incurred fuel and purchased power costs are collected from customers through the FAC.

Rules and procedures for contracts are outlined in the Sarbanes Oxley documentation.

Rules and procedures for the hedging program are in the Risk Management Policy.

(M) A complete explanation of the specific customer class rate design used to design the proposed RAM base amount in permanent rates and any subsequent rate adjustments during the term of the proposed RAM:

The rate design for base rates reflects the fuel and purchased power costs, revenues and transmission costs recovered on a per kWh basis, consistent with the FAC. The rate design for the FAC is to bill all retail customers on a per kWh basis for the incremental costs above or below base rates.

As required, the FAC allocates cost by voltage level. A recent study is currently underway and will be completed prior to the implementation of the FAC.

(N) A complete explanation of any change in business risk to the electric utility resulting from implementation of the proposed RAM in setting the electric utility's allowed return in any rate proceeding, in addition to any other changes in business risk experienced by the electric utility:

See Direct Testimony of Bob Hevert.

(O) The supply-side and demand-side resources that the electric utility expects to use to meet its loads in the next four (4) true-up years, the expected dispatch of those resources, the reasons why these resources are appropriate for dispatch and the heat rates and fuel types for each supply-side resource; in submitting this information, it is recognized that supply- and demand-side resources and dispatch may change during the next four (4) true-up years based upon changing circumstances and parties will have the opportunity to comment on this information after it is filed by the electric utility:

See Direct Testimony of Burton L. Crawford.

(P) A proposed schedule and testing plan with written procedures for heat rate tests and/or efficiency tests for all of the electric utility's nuclear and non-nuclear generators, steam, gas, and oil turbines and heat recovery steam generators (HRSG) to determine the base level of efficiency for each of the units:

See Direct Testimony of Burton L. Crawford.

(Q) Information that shows that the electric utility has in place a long-term resource planning process, important objectives of which are to minimize overall delivered energy costs and provide reliable service::

KCP&L has a long-term resource planning process. The electric utility resource plan produced by the process is also known as an integrated resource plan or IRP. An objective of this planning process is to identify the least cost and preferred resource plans while maintaining adequate capacity reserves for reliability.

KCP&L prepared and filed its last Triennial IRP report on April 9, 2012. Annual updates were filed on June 20, 2013 and March 20, 2014. Under the current IRP rules, the next Triennial IRP filing is to be filed on April 1, 2015.

(R) If emissions allowance costs or sales margins are included in the RAM request and not in the electric utility's environmental cost recovery surcharge, a complete explanation of forecasted environmental investments and allowances purchases and sales; and

See Direct Testimony of Wm. Edward Blunk for the discussion of the allowance purchases and sales and the direct testimony of Burton L. Crawford for the explanation of forecasted environmental investments.

(S) Authorization for the commission staff to release the previous five (5) years of historical surveillance reports submitted to the commission staff by the electric utility to all parties to the case.

Yes. On behalf of KCP&L, I hereby provide Staff that authorization.

Important Notice

Kansas City Power & Light Company ("Company" or "KCP&L") has filed a rate increase request with the Missouri Public Service Commission ("PSC"). The increase would total approximately 15.8% in its Missouri service territory. For the average residential customer, the proposed increase would be approximately $14 per month.

One of the primary reasons for the proposed increase is the utility's need to recover costs for federal and state-mandated environmental upgrades at its La Cygne power plant. These investments will allow La Cygne, one of the company's largest and lowest cost coal-fired power plants, to continue operating after June 2015, when major environmental regulations go into effect.

KCP&L is also seeking to recover costs associated with the significant needed reliability investments it has made in recent years. The utility has replaced aging infrastructure and made system improvements, such as modernizing substations, which allow KCP&L to respond even quicker to power outages.

For more information about request visit www.kcpl.com/MissouriRates.

The Company has also asked the PSC to establish a Fuel Adjustment Clause ("FAC").
The FAC allows the Company to recover from customers the varying cost of fuel, power purchased and transmission costs. Any increase or decrease in fuel costs is reflected in the FAC. The FAC amount will appear as a new line item on the bill. The FAC amount is calculated by multiplying the FAC factor by the kWh's used during the month. The FAC factor changes every six months after fuel costs have been incurred. KCP&L will submit a filing for the Commission to review and approve the FAC twice annually.

A local public hearing (or evidentiary hearing) has been set before the PSC at ____o'clock, on (date) at _________, (address), City, Missouri. The hearing will be held in a facility that meets the accessibility requirements of the Americans with Disabilities Act. Any person who needs additional accommodations to participate in this hearing should call the Public Service Commission's hotline at 1-800-392-4211 (voice) or Relay Missouri at 711 before the hearing.

Consumers wishing to comment on the rate proposal may also: Mail a written comment to the Public Service Commission, P.O. Box 360, Jefferson City, Missouri 65102; Electronically submit a comment to the PSC through the Internet by accessing the PSC's Electronic Filing and Information System at https://www.efis.psc.mo.gov/mpsc (Case No. ER-2014-0370); or Contact the Office of the Public Counsel, P.O. Box 2230, Jefferson City, Missouri 65102, telephone 573-751-4857 or toll-free 866-922-2959, opcservice@ded.mo.gov. Comments are viewable by the public. Do not include any information in a public comment that you do not wish to be made public.

Fuel Adjustment Clause (FAC) Proposed Customer Notice to be inserted in bills upon approval of FAC (anticipated August 2015)
DRAFT - 10/20/2014

Fuel cost increases and decreases will now appear as a separate line item on your bill.

The Missouri Public Service Commission recently approved KCP&L to list fuel costs as a separate line item on monthly billing statements. The name of this line item is the Fuel Adjustment Clause (FAC).

The FAC was established by Missouri legislation in response to the highly volatile prices of fuels needed to generate electricity, and has been in place since 2006 for a large portion of our KCP&L service area in Missouri. In the portion of our Missouri service area you live in, fuel costs have been estimated and placed into the energy charge on your bill. These estimates can quickly become outdated.

The new FAC line item allows you to see fuel-related costs separately from the base energy charge. It reflects increases or decreases in fuel costs, allowing customers to benefit immediately from lower market prices, or cover higher than anticipated fuel costs. These fuel costs include natural gas, coal and associated freight costs, as well as purchased power and transmission costs.

By using actual costs, rather than estimates, customers only pay for the cost of fuel they use and benefit from decreases in cost sooner. Billing line items like the FAC ultimately lower our cost of service to you. They help KCP&L recover our costs faster, therefore improving reliability and lowering overall operating costs.

How will the FAC appear on the bill?

Beginning INSERT DATE, the FAC amount will appear as a new line item on the bill and a average residential customer using INSERT TYPICAL USEAGE IN kWh of electricity will see about INSERT AMOUNT increase per month for this adjustment. (NOTE THAT ALL NUMBERS IN THE EXAMPLE WILL NEED TO BE UPDATED)

Account Number:	**1234 5678 90**
Billing Date:	INSERT DATE
Amount Billed:	INSERT AMOUNT
Customer Charge	$ 9.00
Energy Charge - 600 kWh @ $0.10929	$ 65.57
Energy Charge - 267 kWh @ $0.06552	$ 17.49
DSIM Charge - 867 kWh @ $0.00398	$ 3.45
FAC - 867 kWh @ $INSERT FACTOR	INSERT AMOUNT
Franchise Fee	INSERT AMOUNT
State Sales Tax	INSERT AMOUNT
County Sales Tax	INSERT AMOUNT
City Sales Tax	INSERT AMOUNT

The FAC factor is recalculated every six months and is trued-up each year.

- The FAC amount is calculated by multiplying the FAC factor by the KWh used during the month.
- The FAC factor changes every six months after fuel costs have been incurred. Any over or under recovery is collected/returned over a 12-month period.
- The Missouri Public Service Commission approved the FAC factor of XXX for INSERT DATE to INSERT DATE.
- KCP&L will submit a filing for the Commission to review and approval twice annually. This ensures the correct amount is collected from customers.

DEFINITIONS

ACCUMULATION PERIODS, FILING DATES AND RECOVERY PERIODS: An accumulation period is the six calendar months during which the actual costs and revenues subject to this rider will be accumulated for the purposes of determining the Fuel Adjustment Rate (FAR). The two six-month accumulation periods each year through September 30, 2019, the two corresponding twelve-month recovery periods and the filing dates are as shown below. Each filing shall include detailed work papers in electronic format to support the filing.

Accumulation Periods	Filing Dates	Recovery Periods
October – March	By May 1	July – June
April – September	By November 1	January – December

A recovery period consists of the months during which the FAR is applied to retail customer billings on a per kilowatt-hour (kWh) basis.

COSTS AND REVENUES: Costs eligible for the Fuel and Purchased Power Adjustment (FPA) will be the Company's allocated jurisdictional costs for the fuel component of the Company's generating units, purchased power energy charges including applicable Southwest Power Pool charges (SPP), emission allowance costs, transmission of electricity by others costs, RTO, FERC and NERC fees, and the costs described below associated with the Company's hedging programs - all as incurred during the accumulation period. These costs will be offset by jurisdictional off-system sales revenues, applicable SPP revenues, and revenue from the sale of Renewable Energy Certificates or Credits (REC). Eligible costs do not include the purchased power demand costs associated with purchased power contracts in excess of one year. Likewise revenues do not include demand or capacity receipts associated with power contracts in excess of one year.

APPLICABILITY

The price per kWh of electricity sold to retail customers will be adjusted (up or down) periodically subject to application of the Rider FAC and approval by the Missouri Public Service Commission ("MPSC" or "Commission").

The FAR is the result of dividing the FPA by forecasted retail net system input (S_{RP}) for the recovery period, expanded for Voltage Adjustment Factors (VAF), rounded to the nearest $0.00001, and aggregating over two accumulation periods. The amount charged on a separate line on retail customers' bills is equal to the current annual FAR times kWh billed.

FUEL ADJUSTMENT CLAUSE – Schedule FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided October 1, 2015 and Thereafter)

FORMULAS AND DEFINITIONS OF COMPONENTS

FPA = 100% * ((ANEC – B) * J) + T + I + P

ANEC = Actual Net Energy Costs = (FC + E + PP + TC – OSSR - R)

FC = Fuel Costs Incurred to Support Sales:
The following costs reflected in Federal Energy Regulatory Commission (FERC) Account Number 501: coal commodity and transportation, accessorial charges, applicable taxes, natural gas costs, alternative fuels (i.e. tires, bio-fuel), fuel quality adjustments, fuel hedging costs, fuel adjustments included in commodity and transportation costs, broker commissions, fees and margins, oil costs, propane costs, combustion product disposal revenues and expenses, fuel additives such as side release or freeze conditioning agents and consumable costs related to Air Quality Control Systems (AQCS) operation, such as ammonia, lime, limestone, powder activated carbon, propane, sodium bicarbonate, sulfur, trona, urea, or other consumables which perform similar functions, and insurance recoveries, subrogation recoveries and settlement proceeds for increased fuel expenses in Account 501.

The following costs reflected in FERC Account Number 518: nuclear fuel commodity and waste disposal expense, oil, and nuclear fuel hedging costs.

The following costs reflected in FERC Account Number 547: natural gas, oil, and alternative fuel generation costs related to commodity, transportation, storage, fuel losses, hedging costs for natural gas, oil, and natural gas used to cross-hedge purchased power or sales, fuel additives, and settlement proceeds, insurance recoveries, subrogation recoveries for increased fuel expenses, and broker commissions fees and margins.

E = Net Emission Costs:
The following costs and revenues reflected in FERC Account Numbers 509: emission allowance costs offset by revenues from the sale of emission allowances including any associated hedging costs, and broker commissions, fees, commodity based services, and margins.

FUEL ADJUSTMENT CLAUSE – Schedule FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided October 1, 2015 and Thereafter)

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

PP = Purchased Power Costs:
The following costs or revenues reflected in FERC Account Number 555: purchased power costs, capacity charges for capacity purchases less than 12 months in duration, energy charges from capacity purchases of any duration, insurance recoveries, and subrogation recoveries for purchased power expenses, hedging costs including broker commissions, fees and margins, charges and credits related to the SPP Integrated Marketplace including, energy, make whole and out of merit payments and distributions, Over collected losses payments and distributions, TCR and ARR settlements, virtual energy costs, revenues and related fees where the virtual energy transaction is a hedge in support of physical operations related to a generating resource or load, load/export charges, ancillary services including non-performance and distribution payments and charges and other miscellaneous SPP Integrated Market charges including, but not limited to uplift charges or credits.

TC = Transmission Costs:
The following costs reflected in FERC Account Numbers 561.4, 561.8, 565, 575.7, and 928: all transmission service costs reflected in FERC Account 565 and all transmission service revenues reflected in FERC Account 456.1. Also, includes RTO, FERC, and NERC fees recorded in Accounts, 561.4, 561.8, 575.7, and 928.

The costs described above will be adjusted, where applicable, to comply with the Commission order regarding Transource Docket No. EA-2013-0098.

OSSR = Revenues from Off-System Sales:
The following revenues or costs reflected in FERC Account Number 447: all revenues from off-system sales. This includes charges and credits related to the SPP Integrated Marketplace including, energy, make whole and out of merit payments and distributions, Over collected losses payments and distributions, TCR and ARR settlements, virtual energy costs, revenues and related fees where the virtual energy transaction is a hedge in support of physical operations related to a generating resource or load, generation/export charges, ancillary services including non- performance and distribution payments and charges and other miscellaneous SPP Integrated Market charges including, but not limited to, uplift charges or credits.

R = Renewable Energy Credit Revenue:
Revenues reflected in FERC account 509 from the sale of Renewable Energy Credits that are not needed to meet the Renewable Energy Standard.

FUEL ADJUSTMENT CLAUSE – Schedule FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided October 1, 2015 and Thereafter)

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

Any cost identified above which is a Missouri-only cost shall be grossed up by the current kWh energy factor, included in the ANEC calculation and allocated as indicated in item J below. Any cost identified above which is a Kansas-only cost shall be excluded from the ANEC calculation.

Hedging costs are defined as realized losses and costs (including Commissions, fees, and margins) minus realized gains associated with mitigating volatility in the Company's cost of fuel, fuel additives, fuel transportation, emission allowances, transmission and power purchases or sales, including but not limited to, the Company's use of derivatives whether over-the counter or exchange traded including, without limitation, futures or forward contracts, puts, calls, caps, floors, collars, swaps, transmission congestions rights, virtual energy transactions, or similar instruments.

Should FERC require any item covered by factors FC, E, PP, TC, OSSR or R to be recorded in an account different than the FERC accounts listed in such factors, such items shall nevertheless be included in factor FC, E, PP, TC, OSSR or R. In the month that the Company begins to record items in a different account, the Company will file with the Commission the previous account number, the new account number and what costs or revenues that flow through this Rider FAC that are to be recorded in the account.

B = Net base energy costs ordered by the Commission in the last general rate case consistent with the costs and revenues included in the calculation of the FPA. Base Energy costs will be calculated as shown below:

S_{AP} x Base Factor (BF)

S_{AP} = Net system input (NSI) in kWh for the accumulation period

J = Missouri Retail Energy Ratio = Missouri Retail kWh Sales/Total Retail kWh Sales

T = True-up amount as defined below.

I = Interest applicable to (i) the difference between Missouri Retail ANEC and B for all kWh of energy supplied during an AP until those costs have been recovered; (ii) refunds due to prudence reviews ("P"), if any; and (iii) all under- or over-recovery balances created through operation of this FAC, as determined in the true-up filings ("T") provided for herein. Interest shall be calculated monthly at a rate equal to the weighted average interest paid on the Company's short-term debt, applied to the month-end balance of items (i) through (iii) in the preceding sentence.

P = Prudence disallowance amount, if any, as defined in this tariff.

FUEL ADJUSTMENT CLAUSE – Schedule FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided October 1, 2015 and Thereafter)

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

FAR = FPA/S_{RP}

Single Accumulation Period Secondary Voltage FAR_{Sec} = FAR * VAF_{Sec}
Single Accumulation Period Primary Voltage FAR_{Prim} = FAR * VAF_{Prim}

Annual Secondary Voltage FAR_{Sec} = Aggregation of the two Single Accumulation Period Secondary Voltage FARs still to be recovered

Annual Primary Voltage FAR_{Prim} = Aggregation of the two Single Accumulation Period Primary Voltage FARs still to be recovered

Where:

FPA = Fuel and Purchased Power Adjustment

S_{RP} = Forecasted recovery period Missouri retail NSI in kWh, at the generator

VAF = Expansion factor by voltage level
VAF_{Sec} = Expansion factor for lower than primary voltage customers
VAF_{Prim} = Expansion factor for primary and higher voltage customers

BASE FACTOR (BF)

Company base factor costs per kWh: $0.01547

TRUE-UPS

After completion of each RP, the Company shall make a true-up filing by the filing date of its FAR filing. Any true-up adjustments shall be reflected in "T" above. Interest on the true-up adjustment will be included in item I above.

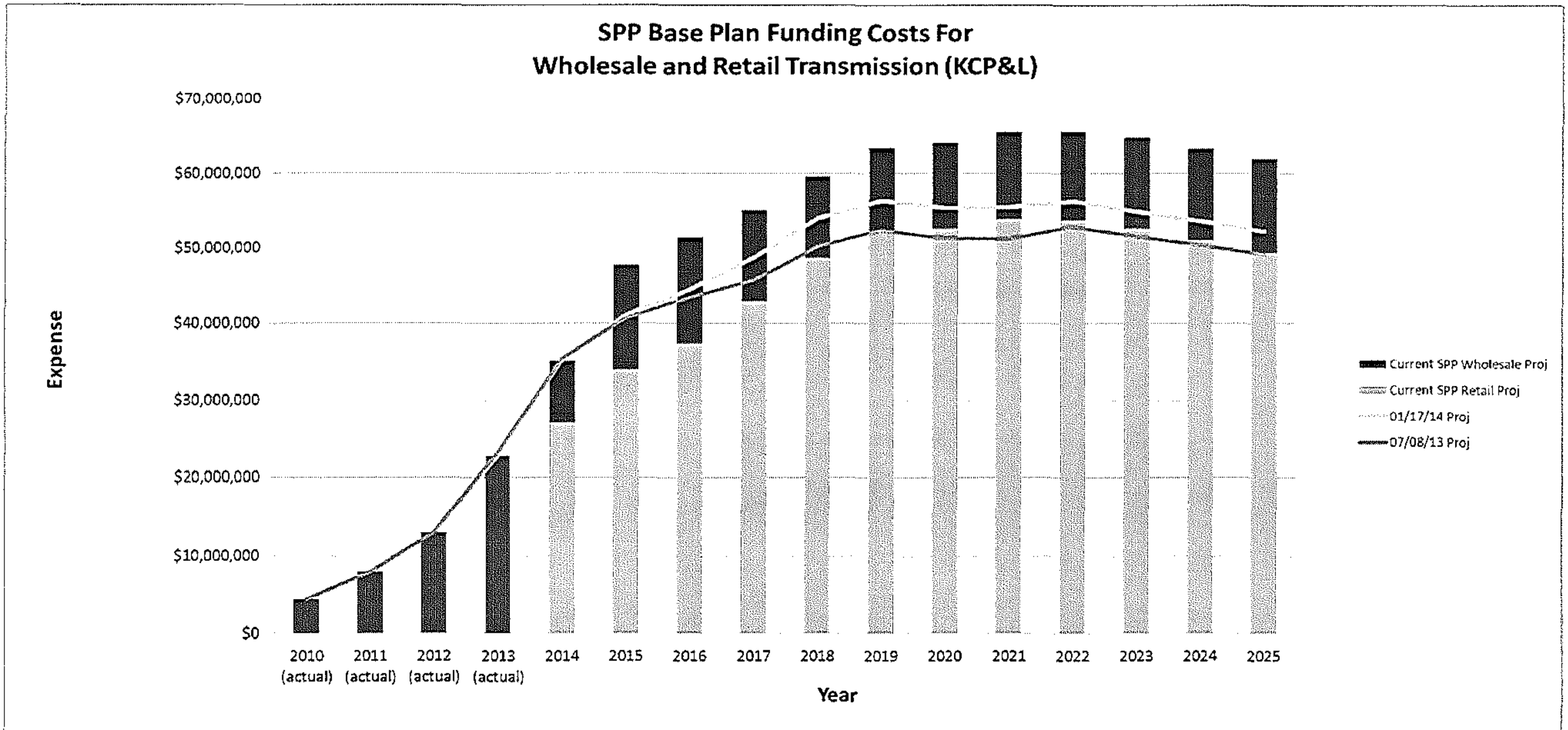
The true-up amount shall be the difference between the revenues billed and the revenues authorized for collection during the RP as well as any corrections identified to be included in the current FAR filing. Any corrections included will be discussed in the testimony accompanying the true-up filing.

PRUDENCE REVIEWS

Prudence reviews of the costs subject to this Rider FAC shall occur no less frequently than every eighteen months, and any such costs which are determined by the Commission to have been imprudently incurred or incurred in violation of the terms of this Rider FAC shall be returned to customers. Adjustments by Commission order, if any, pursuant to any prudence review shall be included in the FAR calculation in item "P" above unless a separate refund is ordered by the Commission. Interest on the prudence adjustment will be included in item "I" above.

FUEL ADJUSTMENT CLAUSE – Schedule FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided October 1, 2015 and Thereafter)

Accumulation Period Ending:			Month dd, yyyy
			KCPL-MO
1	Actual Net Energy Cost (ANEC) = (FC+E+PP+TC-OSSR-R)		$0
2	Net Base Energy Cost (B)	-	$0
	2.1 Base Factor (BF)		$0
	2.2 Accumulation Period NSI (S_{AP})		0
3	(ANEC-B)		$0
4	Jurisdictional Factor (J)	*	0%
5	(ANEC-B)*J		$0
6	Customer Responsibility	*	100%
7	100% *((ANEC-B)*J)		$0
8	True-Up Amount (T)	+	$0
9	Interest (I)	+	$0
10	Prudence Adjustment Amount (P)	+	$0
11	Fuel and Purchased Power Adjustment (FPA)	=	$0
12	Estimated Recovery Period Retail NSI (S_{RP})	÷	0
13	Current Period Fuel Adjustment Rate (FAR)	=	$0.00000
14	Current Period FAR_{Prim} = FAR x VAF_{Prim}		$0.00000
15	Prior Period FAR_{Prim}	+	$0.00000
16	Current Annual FAR_{Prim}		$0.00000
17	Current Period FAR_{Sec} = FAR x VAF_{Sec}		$0.00000
18	Prior Period FAR_{Sec}	+	$0.00000
19	Current Annual FAR_{Sec}		$0.00000
	VAF_{Prim} = 1.0452		
	VAF_{Sec} = 1.0707		



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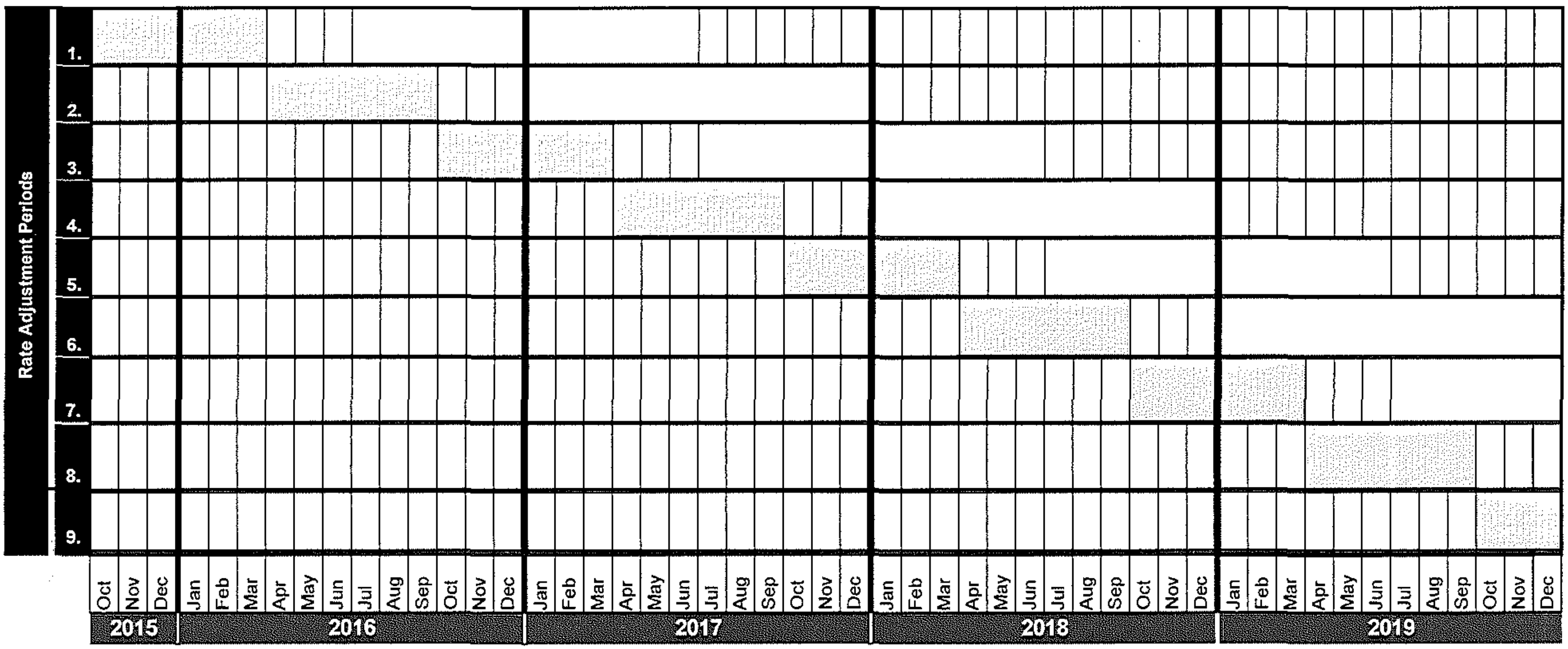
[1] Projections for Current SPP Retail Proj time series taken from : July 24 2014 Cost Allocation Forecast incl HPILS for RTWG posting on August 4 2014.xlsx, Maintained by SPP Engineering, Posted August 4, 2014, http://www.spp.org/publications/July%202014%2010%20Year%20Forecast%20of%20Allocated%20Costs%20for%20Posting%20to%20RTWG.zip.

[2] Projections for 01/17/14 Proj time series taken from : Jan 17 2014 ATRR Forecast All Upgrades w 2014 ITPNT w Forecast BP True Up for Posting on Jan 31 2014.xlsx, Maintained by SPP Engineering, Posted January 31, 2014. http://www.spp.org/publications/2014%20January%2010%20Year%20Cost%20Allocation%20Forecast.zip.

[3] Projections for 07/08/13 Proj time series taken from: July 8 2013 ATRR Forecast All upgrades for Posting, Maintained by SPP Engineering, Posted July 8, 2013. http://www.spp.org/publications/July%208,%202013%20ATRR%20Forecast%20All%20Upgrades.zip.

KCP&L Fuel Adjustment Clause (FAC) Timeline



FAC Accumulation Periods: October - March; April - September

FAC Recovery Periods: July - June; January - December

Kansas City Power & Light Company
2015 RATE CASE - Direct
COST OF SERVICE - Missouri Jurisdiction
TY 3/31/14; Update 10/31/14; K&M 4/30/15

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	MISSOURI RETAIL	RESIDENTIAL	SMALL GEN. SERVICE	MEDIUM GEN. SERVICE	LARGE GEN. SERVICE	LARGE PWR SERVICE	TOTAL LIGHTING	
		(a)	(b)	(c)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	0010	SCHEDULE 1 - SUMMARY OF OPERATING INC & RATE BASE								1	
1	0020		Reference								
1	0030	OPERATING REVENUE									
1	0040	RETAIL SALES REVENUE	TSFR 9 90	767,355,793	285,159,916	48,836,426	103,290,211	180,113,158	140,231,588	9,724,494	
1	0050	OTHER OPERATING REVENUE	TSFR 9 340	413,609,396	125,694,904	19,878,505	53,451,055	107,218,025	103,223,236	4,143,671	
1	0060	TOTAL OPERATING REVENUE		1,180,965,189	410,854,821	68,714,931	156,741,266	287,331,183	243,454,824	13,868,164	
1	0070										
1	0080	OPERATING EXPENSES									
1	0090	FUEL	TSFR 9 4090	222,511,027	67,464,123	10,671,489	28,771,035	57,686,279	55,713,765	2,204,337	
1	0100	PURCHASED POWER	TSFR 9 4100	304,735,754	92,266,295	14,608,136	39,377,911	79,157,649	76,274,910	3,050,853	
1	0110	OTHER OPERATION & MAINTENANCE EXPENSES	TSFR 9 4110	303,491,601	130,026,972	18,284,387	35,816,395	60,927,309	54,962,276	3,474,261	
1	0120	DEPRECIATION EXPENSES (AFTER CLEARINGS)	TSFR 5 1390	116,953,542	47,708,475	6,783,912	15,313,071	24,968,679	21,058,648	1,120,757	
1	0130	AMORTIZATION EXPENSES	TSFR 9 4590	15,665,901	6,229,066	889,814	2,038,733	3,438,636	2,920,334	149,319	
1	0140	TAXES OTHER THAN INCOME TAXES	TSFR 9 4710	58,619,563	23,770,517	3,385,716	7,505,629	12,627,663	10,755,021	575,017	
1	0150	CURRENT INCOME TAXES	TSFR 11 620	14,819,681	(964,231)	2,888,460	4,829,807	8,072,208	(889,421)	882,857	
1	0160	DEFERRED INCOME TAXES	TSFR 11 710	15,669,609	6,370,252	902,973	2,020,562	3,375,818	2,846,949	153,056	
1	0170	TOTAL ELECTRIC OPERATING EXPENSES		1,052,466,678	372,871,468	58,414,886	135,673,145	250,254,241	223,642,482	11,610,457	
1	0180										
1	0190	NET ELECTRIC OPERATING INCOME		128,498,510	37,983,352	10,300,046	21,068,121	37,076,943	19,812,342	2,257,707	
1	0200										
1	0210	RATE BASE									
1	0220	TOTAL ELECTRIC PLANT	TSFR 3 190	5,043,175,544	2,037,927,641	289,127,240	649,823,489	1,092,322,280	925,846,375	48,128,519	
1	0230	LESS: ACCUM. PROV. FOR DEPREC	TSFR 6 1700	2,040,172,942	825,807,274	118,483,601	258,914,132	438,279,127	373,460,443	25,228,365	
1	0240	NET PLANT		3,003,002,603	1,212,120,367	170,643,639	390,909,357	654,043,153	552,385,932	22,900,155	
1	0250	PLUS:									
1	0260	CASH WORKING CAPITAL	TSFR 2 30	(58,530,428)	(23,131,624)	(3,536,975)	(7,677,033)	(12,996,521)	(10,567,841)	(620,435)	
1	0270	MATERIALS & SUPPLIES	TSFR 2 100	57,386,822	21,630,951	3,118,421	7,437,598	13,157,591	11,598,429	443,832	
1	0280	PREPAYMENTS	TSFR 2 170	6,397,922	2,460,858	349,271	805,085	1,446,386	1,293,107	43,215	
1	0290	FUEL INVENTORY	TSFR 2 240	80,107,604	24,200,924	3,835,784	10,358,639	20,800,550	20,110,413	801,295	
1	0300	REGULATORY ASSETS	TSFR 2 360	111,292,579	43,575,623	7,503,232	13,548,672	24,415,751	21,199,957	1,049,344	
1	0310	LESS:									
1	0320	CUSTOMER ADVANCES FOR CONSTRUCTION	TSFR 2 410	167,781	91,553	12,598	22,671	24,733	12,753	3,474	
1	0330	CUSTOMER DEPOSITS	TSFR 2 420	3,567,416	1,780,441	1,424,044	301,429	56,982	4,521	0	
1	0340	DEFERRED INCOME TAXES	TSFR 2 430	599,672,820	242,325,456	34,379,479	77,269,070	129,885,620	110,090,339	5,722,856	
1	0350	DEFERRED GAIN ON SO2 EMISSIONS ALLOWANCE	TSFR 2 440	39,136,133	11,833,473	1,875,216	5,058,000	10,170,874	9,807,708	390,863	
1	0360	DEFERRED GAIN(LOSS) EMISSIONS ALLOWANCE	TSFR 2 450	23,191	7,012	1,111	2,997	6,027	5,812	232	
1	0370	TOTAL RATE BASE		2,557,089,761	1,024,819,164	144,220,924	332,728,152	560,722,675	476,098,864	18,499,982	
1	0380										
1	0390	RATE OF RETURN		5.025%	3.706%	7.142%	6.332%	6.612%	4.161%	12.204%	
1	0400	RELATIVE RATE OF RETURN		1.00	0.74	1.42	1.26	1.32	0.83	2.43	
1	0410										
1	0420										
1	0430										
1	0440										
1	0450										
1	0460										
1	0470										
1	0480										
1	0490										
1	0500										

Kansas City Power & Light Company
2015 RATE CASE - Direct
COST OF SERVICE - Missouri Jurisdiction
TY 3/31/14; Update 10/31/14; K&M 4/30/15

SCH NO.	LINE NO.	DESCRIPTION	ALLOCATION BASIS	MISSOURI RETAIL	RESIDENTIAL	SMALL GEN. SERVICE	MEDIUM GEN. SERVICE	LARGE GEN. SERVICE	LARGE PWR SERVICE	TOTAL LIGHTING	
		(a)	(b)	(c)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	0510	**SCHEDULE 1 - SUMMARY AT EQUALIZED CLAIMED RATE OF RETURN**									
1	0520		Reference								
1	0530	RATE BASE									
1	0540	TOTAL ELECTRIC PLANT	TSFR 3 190	5,043,175,544	2,037,927,641	289,127,240	649,823,489	1,092,322,280	925,846,375	48,128,519	
1	0550	LESS: ACCUM. PROV. FOR DEPREC	TSFR 6 1700	2,040,172,942	825,807,274	118,483,601	258,914,132	438,279,127	373,460,443	25,228,365	
1	0560	NET PLANT		3,003,002,603	1,212,120,367	170,643,639	390,909,357	654,043,153	552,385,932	22,900,155	
1	0570	PLUS:									
1	0580	CASH WORKING CAPITAL	TSFR 2 30	(58,530,428)	(23,131,624)	(3,536,975)	(7,677,033)	(12,996,521)	(10,567,841)	(620,435)	
1	0590	MATERIALS & SUPPLIES	TSFR 2 100	57,386,822	21,630,951	3,118,421	7,437,598	13,157,591	11,598,429	443,832	
1	0600	PREPAYMENTS	TSFR 2 170	6,397,922	2,460,858	349,271	805,085	1,446,386	1,293,107	43,215	
1	0610	FUEL INVENTORY	TSFR 2 240	80,107,604	24,200,924	3,835,784	10,358,639	20,800,550	20,110,413	801,295	
1	0620	REGULATORY ASSETS	TSFR 2 360	111,292,579	43,575,623	7,503,232	13,548,672	24,415,751	21,199,957	1,049,344	
1	0630	LESS:									
1	0640	CUSTOMER ADVANCES FOR CONSTRUCTION	TSFR 2 410	167,781	91,553	12,598	22,671	24,733	12,753	3,474	
1	0650	CUSTOMER DEPOSITS	TSFR 2 420	3,567,416	1,780,441	1,424,044	301,429	56,982	4,521	0	
1	0660	DEFERRED INCOME TAXES	TSFR 2 430	599,672,820	242,325,456	34,379,479	77,269,070	129,885,620	110,090,339	5,722,856	
1	0670	DEFERRED GAIN ON SO2 EMISSIONS ALLOWANCE	TSFR 2 440	39,136,133	11,833,473	1,875,216	5,058,000	10,170,874	9,807,708	390,863	
1	0680	DEFERRED GAIN(LOSS) EMISSIONS ALLOWANCE	TSFR 2 450	23,191	7,012	1,111	2,997	6,027	5,812	232	
1	0690	TOTAL RATE BASE		2,557,089,761	1,024,819,164	144,220,924	332,728,152	560,722,675	476,098,864	18,499,982	
1	0700	OPERATING INCOME @ 7.938% ROR		202,981,785	81,350,145	11,448,257	26,411,961	44,510,166	37,792,728	1,468,529	
1	0710										
1	0720	OPERATING EXPENSES									
1	0730	FUEL	TSFR 9 4090	222,511,027	67,464,123	10,671,489	28,771,035	57,686,279	55,713,765	2,204,337	
1	0740	PURCHASED POWER	TSFR 9 4100	304,735,754	92,266,295	14,608,136	39,377,911	79,157,649	76,274,910	3,050,853	
1	0750	OTHER OPERATION & MAINTENANCE EXPENSES	TSFR 9 4110	303,491,601	130,026,972	18,284,387	35,816,395	60,927,309	54,962,276	3,474,261	
1	0760	DEPRECIATION EXPENSES	TSFR 5 1390	116,953,542	47,708,475	6,783,912	15,313,071	24,968,679	21,058,648	1,120,757	
1	0770	AMORTIZATION EXPENSES	TSFR 9 4590	15,665,901	6,229,066	889,814	2,038,733	3,438,636	2,920,334	149,319	
1	0780	TAXES OTHER THAN INCOME TAXES	TSFR 9 4710	58,619,563	23,770,517	3,385,716	7,505,629	12,627,663	10,755,021	575,017	
1	0790	CURRENT INCOME TAXES	TSFR 11 620	14,819,681	(964,231)	2,888,460	4,829,807	8,072,208	(889,421)	882,857	
1	0800	DEFERRED INCOME TAXES	TSFR 11 710	15,669,609	6,370,252	902,973	2,020,562	3,375,818	2,846,949	153,056	
1	0810	PLUS: ADDITIONAL CURRENT TAX REQUIRED		46,411,273	27,022,282	715,462	3,329,800	4,631,716	11,203,758	(491,745)	
1	0820	TOTAL ELECTRIC OPERATING EXPENSES		1,098,877,952	399,893,750	59,130,348	139,002,945	254,885,957	234,846,240	11,118,712	
1	0830										
1	0840	COST OF SERVICE		1,301,859,737	481,243,896	70,578,605	165,414,905	299,396,123	272,638,968	12,587,241	
1	0850	LESS: PRESENT OTHER RETAIL SALES REVENUE	TSFR 9 60	760,901	282,761	48,426	102,421	178,598	139,052	9,643	
1	0860	LESS: PRESENT OTHER REVENUE	TSFR 9 340	413,609,396	125,694,904	19,878,505	53,451,055	107,218,025	103,223,236	4,143,671	
1	0870	RETAIL SALES REVENUE		887,489,440	355,266,230	50,651,674	111,861,429	191,999,499	169,276,680	8,433,927	
1	0880										
1	0890	TOTAL REVENUE ADJUSTMENT		120,894,548	70,389,075	1,863,674	8,673,640	12,064,939	29,184,144	(1,280,923)	
1	0900	PERCENT CHANGE		15.75%	24.68%	3.82%	8.40%	6.70%	20.81%	-13.17%	
1	0910										
1	0920										
1	0930										
1	0940										
1	0950										
1	0960										
1	0970										
1	0980										
1	0990										
1	1000										

Kansas City Power & Light Company
2015 RATE CASE - Direct
TY 3/31/14; Update 10/31/14; K&M 4/30/15

KCPL MO
COST OF SERVICE RESULTS – CLASS ROR AND INDEX

	Index of Return	-------- Rate of Return % --------		
Customer Class	Annual	Annual	Seasonal	
			Summer	Winter
RESIDENTIAL	0.74	3.706%	0.533%	9.003%
Regular	0.75	3.787%	0.390%	10.357%
Time of Day	0.73	3.691%	1.127%	8.153%
All Electric	0.72	3.637%	1.140%	6.640%
Separately Metered	0.57	2.861%	0.741%	4.585%
SMALL GS	1.42	7.142%	1.976%	14.654%
Primary & Secondary	1.42	7.126%	1.959%	14.738%
Other	1.73	8.687%	2.398%	17.801%
All Electric	1.37	6.907%	1.794%	13.026%
Separately Metered	1.39	6.961%	3.315%	10.499%
MEDIUM GS	1.26	6.332%	1.333%	13.616%
Primary	1.65	8.302%	2.667%	14.996%
Secondary	1.28	6.443%	1.347%	14.128%
All Electric	1.05	5.279%	1.106%	9.986%
Separately Metered	1.14	5.747%	1.222%	11.145%
LARGE GS	1.32	6.612%	1.665%	13.027%
Primary	1.51	7.564%	2.098%	15.060%
Secondary	1.39	6.982%	1.748%	14.523%
All Electric	1.14	5.704%	1.339%	10.483%
Separately Metered	1.52	7.628%	2.268%	14.059%
LARGE POWER SERVICE	0.83	4.161%	0.103%	9.447%
Primary	0.95	4.799%	0.513%	10.366%
Secondary	0.93	4.683%	0.372%	10.441%
Substation	0.25	1.241%	-1.348%	4.849%
Transmission	0.78	3.904%	-0.477%	8.918%
TOTAL LIGHTING	2.43	12.204%		
MISSOURI RETAIL	1.00	5.025%		

Kansas City Power & Light Company
2015 RATE CASE - Direct
TY 3/31/14; Update 10/31/14; K&M 4/30/15

KCPL MO
COST OF SERVICE RESULTS – UNBUNDLED CUSTOMER, DEMAND AND ENERGY

	UNIFORM RATE OF RETURN @ 7.94%						
	Monthly ($)	Annual			Demand Costs ($/kWh)		
	Customer	Energy	Seasonal Energy				
Customer Class	Charge (1)	Costs ($)	Costs ($)		Annual	Seasonal	
			Summer	Winter		Summer	Winter
RESIDENTIAL	$25.94	0.0173	0.0183	0.0167	0.0905	0.1543	0.0501
Regular	$24.90	0.0174	0.0183	0.0167	0.0947	0.1565	0.0502
Time of Day	$34.87	0.0173	0.0183	0.0166	0.0896	0.1471	0.0490
All Electric	$28.37	0.0171	0.0181	0.0166	0.0805	0.1457	0.0494
Separately Metered	$35.00	0.0169	0.0181	0.0165	0.0764	0.1492	0.0522
SMALL GS	$35.67	0.0170	0.0180	0.0165	0.0793	0.1399	0.0455
Primary & Secondary	$36.29	0.0170	0.0180	0.0165	0.0796	0.1400	0.0455
Other	$14.27	0.0172	0.0180	0.0168	0.0786	0.1394	0.0465
All Electric	$51.45	0.0168	0.0177	0.0164	0.0734	0.1369	0.0451
Separately Metered	$58.04	0.0167	0.0178	0.0163	0.0721	0.1391	0.0467
MEDIUM GS	$182.75	0.0170	0.0179	0.0164	0.0729	0.1229	0.0442
Primary	$37.69	0.0165	0.0175	0.0160	0.0679	0.1201	0.0440
Secondary	$177.68	0.0170	0.0179	0.0164	0.0735	0.1231	0.0441
All Electric	$252.45	0.0168	0.0178	0.0164	0.0690	0.1220	0.0448
Separately Metered	$234.31	0.0168	0.0179	0.0163	0.0702	0.1226	0.0449
LARGE GS	$351.85	0.0168	0.0178	0.0163	0.0667	0.1112	0.0431
Primary	$140.65	0.0166	0.0175	0.0160	0.0657	0.1091	0.0418
Secondary	$331.58	0.0170	0.0179	0.0164	0.0686	0.1120	0.0432
All Electric	$492.80	0.0167	0.0177	0.0163	0.0644	0.1107	0.0434
Separately Metered	$360.85	0.0168	0.0180	0.0163	0.0661	0.1125	0.0433
LARGE POWER SERVICE	$2,808.15	0.0166	0.0174	0.0161	0.0589	0.0937	0.0391
Primary	$2,419.56	0.0166	0.0174	0.0161	0.0606	0.0960	0.0404
Secondary	$3,434.25	0.0170	0.0178	0.0165	0.0625	0.0983	0.0414
Substation	$2,268.68	0.0165	0.0174	0.0160	0.0549	0.0873	0.0356
Transmission	$2,268.46	0.0160	0.0168	0.0155	0.0510	0.0844	0.0346
TOTAL LIGHTING		0.0170			0.0446		

Notes

1. Includes local facilities

	A	B	C	D
1	**KCP&L-MO RESIDENTIAL**			
2	**SUMMARY OF PROPOSED SCENARIOS**			
3	**ER-2014-0370 Direct Filing**			
4				
5	*INPUT FOR MODEL*			
6	**Cust Chg**	**Current Rates**	**Rates With Increase**	**Proposed Rates**
7				
8	**JURISDICITIONAL INCREASE (%)**		15.8%	
9				
10	**CUSTOMER CHARGE**			
11	One Meter	9.00	25.00	25.00
12	Two Meters - Standard	9.00	25.00	25.00
13	Two Meters - Additional	2.05	5.00	5.00
14		11.05	30.00	30.00
15	**ENERGY CHARGE**			
16	**Summer Rate**			
17	0-600	0.12157	0.12157	0.12712
18	600-1000	0.12157	0.12157	0.12712
19	1000+	0.12157	0.12157	0.12712
20	**Winter Rates**			
21	Winter Gen - RESA/RESC			
22	0-600	0.10929	0.09737	0.09737
23	600-1000	0.06552	0.07548	0.07548
24	1000+	0.05475	0.05423	0.05423
25	Winter Gen&S/H - RESB			
26	0-600	0.08544	0.08544	0.08544
27	600-1000	0.08544	0.07548	0.07548
28	1000+	0.05370	0.05370	0.05370
29	Sep Space Heat Mtr			
30	Winter	0.05494	0.05370	0.05370
31	Summer	0.12157	0.12157	0.12712
32	**Other Use**			
33	Winter	0.12268	0.11168	0.12929
34	Summer	0.15789	0.13420	0.15536
35	**T-O-U (RTOD)**			
36	Customer Charge	14.04	25.00	25.00
37	Summer On-Peak	0.18643	0.21583	0.21583
38	Summer Off-Peak	0.10386	0.12024	0.12024
39	Winter	0.07677	0.07677	0.07677
40				
41	**SmartGrid TOU**			
42	Summer On-Peak	0.3784	0.43807	0.12712
43	Summer Off-Peak	0.0631	0.07305	0.12712
44	Winter TOU-General Use			
45	0-600	0.09914	0.11477	0.09737
46	600-1000	0.05945	0.06883	0.07548
47	1000+	0.04968	0.05751	0.05423
48	Winter TOU-General Use and Space Heat			
49	0-1000	0.07382	0.08546	0.08544
50	1000+	0.04872	0.05640	0.05370
51				
52	Factor RESA	100.00%	114.05%	101.79%
53	Factor RESA - Winter	100.00%	116.85%	100.00%
54	Factor RESB	100.00%	113.10%	101.63%
55	Factor RESB - Winter	100.00%	115.92%	100.00%
56	Factor RESC	100.00%	113.27%	101.32%
57	Factor RESC - Winter	100.00%	112.67%	100.00%
58	Factor T-O-U	100.00%	116.19%	100.00%
59	Overall Change (*)	100.00%	13.83%	15.77%
60	Winter Price Below Summer (SUM-WIN)/SUM	30.1%	33.9%	36.8%

	A	B	C	D	E
1	KCP&L-MO SMALL GENERAL SERVICE				
2	SUMMARY OF PROPOSED SCENARIOS				
3	ER-2014-0370 Direct Filing				
4					
5		*INPUT FOR MODEL*			
6		Cust Chg	Current Rates	Rates With Increase	PROPOSED RATES
7					
8		JURISDICITIONAL INCREASE (%)		15.8%	
9					
10					
11	A: CUSTOMER CHARGE				
12		Metered Service:			
13		0-24 KW	16.45	16.45	19.06
14		25-199 KW	45.60	45.60	52.83
15		200-999 KW	92.64	92.64	107.32
16		1001+ KW	790.99	790.99	916.32
17		Unmetered Service	6.90	6.90	7.99
18		Separately Metered Space Heat	2.12	2.12	2.46
19				-	-
20	B: FACILITIES CHARGE			-	-
21		SECONDARY:		-	-
22		0-25 KW	-	-	-
23		26+ KW	2.650	2.650	3.070
24		PRIMARY:		-	-
25		0-26 KW	-	-	-
26		27+ KW	2.588	2.588	2.998
27				-	-
28	C: ENERGY CHARGE			-	-
29		SECONDARY-SUMMER:		-	-
30		0-180 hrs use per month	0.14682	0.14682	0.17012
31		181-360 hrs use per month	0.06966	0.06966	0.08070
32		361+ hrs use per month	0.06207	0.06207	0.07190
33		SECONDARY-WINTER:		-	-
34		0-180 hrs use per month	0.11408	0.11408	0.13216
35		181-360 hrs use per month	0.05570	0.05570	0.06453
36		361+ hrs use per month	0.05027	0.05027	0.05824
37				-	-
38		PRIMARY-SUMMER:		-	-
39		0-180 hrs use per month	0.14346	0.14346	0.16623
40		181-360 hrs use per month	0.06807	0.06807	0.07886
41		361+ hrs use per month	0.06063	0.06063	0.07024
42		PRIMARY-WINTER:		-	-
43		0-180 hrs use per month	0.11148	0.11148	0.12914
44		181-360 hrs use per month	0.05442	0.05442	0.06304
45		361+ hrs use per month	0.04910	0.04910	0.05688
46				-	-
47		SECONDARY-WINTER - ALL ELECTRIC		-	-
48		0-180 hrs use per month	0.09951	0.09951	0.11528
49		181-360 hrs use per month	0.05737	0.05570	0.06453
50		361+ hrs use per month	0.05465	0.05027	0.05824
51		PRIMARY-WINTER - ALL ELECTRIC		-	-
52		0-180 hrs use per month	0.09724	0.09724	0.11265
53		181-360 hrs use per month	0.05606	0.05442	0.06304
54		361+ hrs use per month	0.05339	0.04910	0.05688
55				-	-
56	D: SEPARATELY METERED S/H-WINTER			-	-
57		SECONDARY	0.06109	0.05027	0.05824
58		PRIMARY	-	-	-
59	SGS Secondary		100.00%	100.11%	115.73%
60	SGS Primary		100.00%	100.89%	114.83%
61	SGS Overall Change (*)		0.00%	0.12%	15.86%
62	SGA Secondary		100.00%	99.40%	115.81%
63	SGA Primary		100.00%	#DIV/0!	#DIV/0!
64	SGA Winter Energy Overall Change			-1.16%	14.51%
65	SGA Overall Change (*)		0.00%	-0.60%	15.11%
66	SGS Secondary Space Heat		100.00%	95.77%	115.86%
67	SGS Secondary Unmetered		0.00%	100.00%	115.84%
68	Winter Price Below Summer (SUM-WIN)/SUM		15.8%	15.9%	16.0%
69	Overall Change			0.04%	15.77%

	A	B	C	D	E
1	**KCP&L-MO MEDIUM GENERAL SERVICE**				
2	**SUMMARY OF PROPOSED SCENARIOS**				
3	**ER-2014-0370 Direct Filing**				
4					
5		*INPUT FOR MODEL*			
6		**Cust Chg**	**Current Rates**	**Rates With Increase**	**PROPOSED RATES**
7					
8		**JURISDICITIONAL INCREASE (%)**		16.1%	
9					
10					
11	A: CUSTOMER CHARGE				
12		0-24 KW	47.67	47.67	55.35
13		25-199 KW	47.67	47.67	55.35
14		200-999 KW	96.82	96.82	112.43
15		1001+ KW	826.71	826.71	959.97
16		Separately Metered Space Heat	2.22	2.22	2.58
17				-	-
18	B: FACILITIES CHARGE			-	-
19		SECONDARY:	2.770	2.770	3.216
20		PRIMARY:	2.296	2.296	2.666
21				-	-
22	C: DEMAND CHARGE			-	-
23		SECONDARY-SUMMER:	3.624	3.624	4.208
24		SECONDARY-WINTER	1.844	1.844	2.141
25		PRIMARY-SUMMER	3.540	3.540	4.111
26		PRIMARY-WINTER	1.800	1.800	2.090
27		SECONDARY-WINTER - ELEC ONLY	2.611	1.844	2.141
28		PRIMARY-WINTER - ELEC ONLY	2.554	1.800	2.090
29				-	-
30	D: ENERGY CHARGE			-	-
31		SECONDARY-SUMMER:		-	-
32		0-180 hrs use per month	0.09473	0.09473	0.11000
33		181-360 hrs use per month	0.06479	0.06479	0.07523
34		361+ hrs use per month	0.05464	0.05464	0.06345
35		SECONDARY-WINTER:		-	-
36		0-180 hrs use per month	0.08185	0.08185	0.09504
37		181-360 hrs use per month	0.04899	0.04899	0.05689
38		361+ hrs use per month	0.04109	0.04109	0.04771
39		PRIMARY-SUMMER:		-	-
40		0-180 hrs use per month	0.09246	0.09246	0.10736
41		181-360 hrs use per month	0.06333	0.06333	0.07354
42		361+ hrs use per month	0.05340	0.05340	0.06201
43		PRIMARY-WINTER:		-	-
44		0-180 hrs use per month	0.07993	0.07993	0.09281
45		181-360 hrs use per month	0.04786	0.04786	0.05557
46		361+ hrs use per month	0.04030	0.04030	0.04680
47		SECONDARY-WINTER - ALL ELECTRIC		-	-
48		0-180 hrs use per month	0.06840	0.06840	0.07943
49		181-360 hrs use per month	0.04109	0.04109	0.04771
50		361+ hrs use per month	0.03568	0.03568	0.04143
51		PRIMARY-WINTER - ALL ELECTRIC		-	-
52		0-180 hrs use per month	0.06686	0.06686	0.07764
53		181-360 hrs use per month	0.04007	0.04007	0.04653
54		361+ hrs use per month	0.03500	0.03500	0.04064
55				-	-
56	E: SEPARATELY METERED S/H-WINTER			-	-
57		SECONDARY	0.05352	0.03568	0.04143
58		PRIMARY		-	-
59					-
60	F: REACTIVE DEMAND ADJUSTMENT		0.694	0.694	0.812
61	MGS Secondary		100.00%	0.26%	16.12%
62	MGS Primary		100.00%	0.14%	16.12%
63	MGS Overall Change (*)		0.00%	0.26%	16.12%
64	MGA Secondary		100.00%	-1.42%	13.95%
65	MGA Primary		100.00%	-2.43%	13.30%
66	MGA Winter Energy Overall Change			0.00%	13.88%
67	MGA Overall Change (*)		0.00%	-1.43%	13.95%
68	MGS Secondary-Space Heat		100.00%	-6.23%	7.95%
69	Winter Price Below Summer (SUM-WIN)/SUM		16.7%	17.3%	17.3%
70	Overall Change			-0.01%	15.77%

	A	B	C	D	E
1	KCP&L-MO LARGE GENERAL SERVICE				
2	SUMMARY OF PROPOSED SCENARIOS				
3	ER-2014-0370 Direct Filing				
4					
5		*INPUT FOR MODEL*			
6		Cust Chg	Current Rates	Rates With Increase	Proposed Rate
7					
8		JURISDICTIONAL INCREASE (%)		15.9%	
9					
10					
11	A: CUSTOMER CHARGE				
12		0-24 KW	101.15	101.15	117.26
13		25-199 KW	101.15	101.15	117.26
14		200-999 KW	101.15	101.15	117.26
15		1001+ KW	863.59	863.59	1,001.15
16		Separately Metered Space Heat	2.32	2.32	2.69
17				-	-
18	B: FACILITIES CHARGE			-	-
19		SECONDARY:	2.894	2.894	3.355
20		PRIMARY:	2.399	2.399	2.781
21				-	-
22	C: DEMAND CHARGE			-	-
23		SECONDARY-SUMMER:	5.778	5.778	6.698
24		SECONDARY-WINTER	3.109	3.109	3.604
25		PRIMARY-SUMMER	5.647	5.647	6.547
26		PRIMARY-WINTER	3.039	3.039	3.523
27		SECONDARY-WINTER - ELEC ONLY	2.879	2.879	3.338
28		PRIMARY-WINTER - ELEC ONLY	2.811	2.811	3.259
29				-	-
30	D: ENERGY CHARGE			-	-
31		SECONDARY-SUMMER:		-	-
32		0-180 hrs use per month	0.08486	0.08486	0.09838
33		181-360 hrs use per month	0.06075	0.06075	0.07043
34		361+ hrs use per month	0.04260	0.04260	0.04939
35		SECONDARY-WINTER:		-	-
36		0-180 hrs use per month	0.07798	0.07798	0.09040
37		181-360 hrs use per month	0.04670	0.04670	0.05414
38		361+ hrs use per month	0.03580	0.03580	0.04150
39				-	-
40		PRIMARY-SUMMER:		-	-
41		0-180 hrs use per month	0.08296	0.08296	0.09617
42		181-360 hrs use per month	0.05930	0.05930	0.06875
43		361+ hrs use per month	0.04160	0.04160	0.04823
44		PRIMARY-WINTER:		-	-
45		0-180 hrs use per month	0.07620	0.07620	0.08834
46		181-360 hrs use per month	0.04558	0.04558	0.05284
47		361+ hrs use per month	0.03510	0.03510	0.04069
48				-	-
49		SECONDARY-WINTER - ALL ELECTRIC		-	-
50		0-180 hrs use per month	0.07141	0.07141	0.08278
51		181-360 hrs use per month	0.04023	0.04023	0.04664
52		361+ hrs use per month	0.03140	0.03140	0.03640
53		PRIMARY-WINTER - ALL ELECTRIC		-	-
54		0-180 hrs use per month	0.06991	0.06991	0.08105
55		181-360 hrs use per month	0.03934	0.03934	0.04561
56		361+ hrs use per month	0.03080	0.03080	0.03571
57				-	-
58	E: SEPARATELY METERED S/H-WINTER			-	-
59		SECONDARY	0.05246	0.03140	0.03640
60		PRIMARY	0.00000	-	-
61				-	-
62	F: REACTIVE DEMAND ADJUSTMENT		0.726	0.726	0.843
64	LGS Secondary		100.00%	0.48%	15.93%
65	LGS Primary		100.00%	0.53%	15.93%
66	LGS Overall Change (*)		0.00%	0.49%	15.93%
67	LGA Secondary		100.00%	0.97%	15.93%
68	LGA Primary		100.00%	0.00%	15.93%
69	LGA Winter Energy Overall Change			0.00%	13.74%
70	LGA Overall Change (*)		0.00%	0.78%	15.93%
71	Winter Price Below Summer (SUM-WIN)/SUM		28.0%	16.4%	16.4%
72	Overall Change			0.409%	15.73%

	A / B	C	D	E
1	**KCP&L-MO LARGE POWER SERVICE**			
2	**SUMMARY OF PROPOSED SCENARIOS**			
3	**ER-2014-0370 Direct Filing**			
4				
5	*INPUT FOR MODEL*			
6	**Cust Chg**	**Current Rates**	**Rates With Increase**	**PROPOSED RATES**
7				
8	**JURISDICITIONAL INCREASE (%)**		**15.5%**	
9				
10				
11	A: CUSTOMER CHARGE			
12		961.50	961.50	1,110.63
13		-	-	-
14		-	-	-
15			-	-
16	B: FACILITIES CHARGE		-	-
17	SECONDARY:	3.220	3.220	3.719
18	PRIMARY:	2.669	2.669	3.083
19	SUBSTATION VOLTAGE	0.806	0.806	0.931
20	TRANSM VOLTAGE	-	-	-
21			-	-
22	C: DEMAND CHARGE		-	-
23	SECONDARY-SUMMER:		-	-
24	First 2443 kw	12.493	12.493	14.431
25	Next 2443 kw	9.993	9.993	11.543
26	Next 2443 kw	8.371	8.371	9.669
27	All kw over 7329 kw	6.111	6.111	7.059
28	SECONDARY-WINTER		-	-
29	First 2443 kw	8.492	8.492	9.809
30	Next 2443 kw	6.626	6.626	7.654
31	Next 2443 kw	5.846	5.846	6.753
32	All kw over 7329 kw	4.500	4.500	5.198
33			-	-
34	PRIMARY-SUMMER		-	-
35	First 2500 kw	12.206	12.206	14.099
36	Next 2500 kw	9.765	9.765	11.280
37	Next 2500 kw	8.179	8.179	9.448
38	All kw over 7500 kw	5.972	5.972	6.898
39	PRIMARY-WINTER		-	-
40	First 2500 kw	8.296	8.296	9.583
41	Next 2500 kw	6.476	6.476	7.480
42	Next 2500 kw	5.712	5.712	6.598
43	All kw over 7500 kw	4.399	4.399	5.081
44			-	-
45	SUBSTATION-SUMMER		-	-
46	First 2530 kw	12.060	12.060	13.931
47	Next 2530 kw	9.648	9.648	11.144
48	Next 2530 kw	8.082	8.082	9.336
49	All kw over 7590 kw	5.901	5.901	6.816
50	SUBSTATION-WINTER		-	-
51	First 2530 kw	8.199	8.199	9.471
52	Next 2530 kw	6.399	6.399	7.392
53	Next 2530 kw	5.646	5.646	6.522
54	All kw over 7590 kw	4.346	4.346	5.020
55			-	-

	A	B	C	D	E
56		TRANSMISSION-SUMMER		-	-
57		First 2553 kw	11.956	11.956	13.810
58		Next 2553 kw	9.562	9.562	11.045
59		Next 2553 kw	8.008	8.008	9.250
60		All kw over 7659 kw	5.848	5.848	6.755
61		TRANSMISSION-WINTER		-	-
62		First 2553 kw	8.125	8.125	9.385
63		Next 2553 kw	6.342	6.342	7.326
64		Next 2553 kw	5.595	5.595	6.463
65		All kw over 7659 kw	4.307	4.307	4.975
66				-	-
67	D: ENERGY CHARGE			-	-
68		SECONDARY-SUMMER:		-	-
69		0-180 hrs use per month	0.07822	0.07822	0.09035
70		181-360 hrs use per month	0.04911	0.04911	0.05673
71		361+ hrs use per month	0.02566	0.02566	0.02964
72		SECONDARY-WINTER:		-	-
73		0-180 hrs use per month	0.06631	0.06631	0.07659
74		181-360 hrs use per month	0.04468	0.04468	0.05161
75		361+ hrs use per month	0.02541	0.02541	0.02935
76				-	-
77		PRIMARY-SUMMER:		-	-
78		0-180 hrs use per month	0.07643	0.07643	0.08828
79		181-360 hrs use per month	0.04800	0.04800	0.05544
80		361+ hrs use per month	0.02507	0.02507	0.02896
81		PRIMARY-WINTER:		-	-
82		0-180 hrs use per month	0.06480	0.06480	0.07485
83		181-360 hrs use per month	0.04365	0.04365	0.05042
84		361+ hrs use per month	0.02484	0.02484	0.02869
85				-	-
86		SUBSTATION-SUMMER		-	-
87		0-180 hrs use per month	0.07554	0.07554	0.08726
88		181-360 hrs use per month	0.04744	0.04744	0.05480
89		361+ hrs use per month	0.02477	0.02477	0.02861
90		SUBSTATION-WINTER		-	-
91		0-180 hrs use per month	0.06405	0.06405	0.07398
92		181-360 hrs use per month	0.04314	0.04314	0.04983
93		361+ hrs use per month	0.02454	0.02454	0.02835
94				-	-
95		TRANSMISSION-SUMMER		-	-
96		0-180 hrs use per month	0.07487	0.07487	0.08648
97		181-360 hrs use per month	0.04701	0.04701	0.05430
98		361+ hrs use per month	0.02456	0.02456	0.02837
99		TRANSMISSION-WINTER		-	-
100		0-180 hrs use per month	0.06346	0.06346	0.07330
101		181-360 hrs use per month	0.04275	0.04275	0.04938
102		361+ hrs use per month	0.02431	0.02431	0.02808
103				-	-
104	E: REACTIVE DEMAND ADJUSTMENT		0.808	0.808	0.935
105				-	-
106	LGS Secondary		100.00%		15.51%
107	LGS Primary		100.00%		15.51%
108	LGS Substation Voltage		100.00%		15.51%
109	LGS Transmission Voltage		100.00%		15.51%
110	LGS Overall Change (*)		0.00%		15.51%
111	Winter Price Below Summer (SUM-WIN)/SUM		12.8%		12.8%
112	Overall Change				15.51%

	A	B	C
1	**Proposed Tariff and Rule Revisions for 2015 KCP&L-MO Rate Case**		
2	**Rates**	**Proposed Change**	**Support/Additional Detail**
3	Table of Contents TOC-1	Update to reflect tariff eliminations and additions.	
4	Table of Contents TOC-2	NEW TARIFF - Include topic view, similar to Kansas TOC.	Proposing alternate, topic-based presentation of the Table of contents to aid users in finding tariff sheets. No customer or revenue impacts.
5	Residential Conservation Service Program 3	Reserve tariff page for future use	The federal law mandating utilities to provide energy audits expired. Audits replaced by MEEIA alternatives. No customer or revenue impacts.
6	Air Conditioner Load Control 4 & 4A	Reserve tariff page for future use	The program is inactive, there are not customers being billed for the device, and based on available information, the devices have been eliminated in the field. No customer or revenue impacts.
7	Residential Service 5A, 5B & 5C	>Proposed rate design changes. >Add rate codes to tariff. >Remove reference to Res Conservation Service Program from Minimum section. >Add FAC section to tariff.	>Add the rate codes used in billing to the tariff sheets. >With Sheet #3 proposed for elimination, we propose to eliminate references to that program within the residential tariffs. >Adding the FAC Section to make the proposed charge applicable to this rate.
8	Residential Other Use 6	>Proposed rate design changes. >Add rate codes to tariff. >Realign other use rates to position the with respect to RES and SGS rates. >Remove reference to Res Conservation Service Program from Minimum section. >Add FAC section to tariff.	>Add the rate codes used in billing to the tariff sheets. >The RES Other rate is intended to provide a residential rate for residential-related needs that are beyond the normal premise. The Company proposes that the rate be positioned between the RES and the Small General Service Rates. >With Sheet #3 proposed for elimination, we propose to eliminate references to that program within the residential tariffs. >Adding the FAC Section to make the proposed charge applicable to this rate.
9	Residential Time of Day Service RTOD 8 & 8A	>Proposed rate design changes. >Add rate codes to tariff. >Propose availability be frozen. >Remove reference to Res Conservation Service Program from Minimum section. >Add FAC section to tariff.	>Add the rate codes used in billing to the tariff sheets. >Current TOD rates are not properly designed, resulting in little customer participation and questionable benefit to the Company. Rate redesign is planned. >With Sheet #3 proposed for elimination, we propose to eliminate references to that program within the residential tariffs. >Adding the FAC Section to make the proposed charge applicable to this rate.
10	Small General Service SGS 9A, 9B, 9D, & 9E	>Proposed rate design changes. >Add rate codes to tariff. >Remove excess language from Facilities Demand section. >Add FAC section to tariff.	>Add the rate codes used in billing to the tariff sheets. > Remove "or any day celebrated as such." from the end of the Facilities Demand section. Proposed in an effort to start standardizing the definition of off-peak periods with in the Company. Current language introduces undefined days into the billing process. >Add FAC Section to tariff. Make FAC applicable to the rate.
11	Medium General Service MGS 10A, 10B, 10C, 10D, & 10E	>Proposed rate design changes. >Add rate codes to tariff. >Remove excess language from Facilities Demand section. >Add FAC section to tariff.	>Add the rate codes used in billing to the tariff sheets. > Remove "or any day celebrated as such." from the end of the Facilities Demand section. Proposed in an effort to start standardizing the definition of off-peak periods with in the Company. Current language introduces undefined days into the billing process. >Add FAC Section to tariff. Make FAC applicable to the rate.

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1	**Proposed Tariff and Rule Revisions for 2015 KCP&L-MO Rate Case**		
2	**Rates**	**Proposed Change**	**Support/Additional Detail**
12	Large General Service LGS 11A, 11B, 11C, 11D, & 11E	>Proposed rate design changes. >Add rate codes to tariff. >Remove excess language from Facilities Demand section. >Add FAC section to tariff.	>Add the rate codes used in billing to the tariff sheets. > Remove "or any day celebrated as such." from the end of the Facilities Demand section. Proposed in an effort to start standardizing the definition of off-peak periods with in the Company. Current language introduces undefined days into the billing process. >Add FAC Section to tariff. Make FAC applicable to the rate.
13	Large Power Service LPS 14A, 14B, 14C, &14E	>Proposed rate design changes. >Add rate codes to tariff. >Add FAC section to tariff.	>Add the rate codes used in billing to the tariff sheets. >Add FAC Section to tariff. Make FAC applicable to the rate.
14	Large Power Service Off Peak Rider 15	>Remove excess language from Facilities Demand section.	> Remove "or any day celebrated as such." from the end of the Facilities Demand section. Proposed in an effort to start standardizing the definition of off-peak periods with in the Company. Current language introduces undefined days into the billing process.
15	Small General Service - All Electric SGA 17A, 17C, & 17D	>Proposed rate design changes. >Add rate codes to tariff. >Remove excess language from Facilities Demand section. >Add FAC section to tariff.	>Add the rate codes used in billing to the tariff sheets. > Remove "or any day celebrated as such." from the end of the Facilities Demand section. Proposed in an effort to start standardizing the definition of off-peak periods with in the Company. Current language introduces undefined days into the billing process. >Add FAC Section to tariff. Make FAC applicable to the rate.
16	Medium General Service - All Electric MGA 18A, 18B, 18C, 18D, & 18E	>Proposed rate design changes. >Add rate codes to tariff. >Remove special facilities demand language. >Remove excess language from Facilities Demand section. >Add FAC section to tariff.	>Add the rate codes used in billing to the tariff sheets. >Code STHE is frozen and no longer used in this tariff. Proposing removal. > Remove "or any day celebrated as such." from the end of the Facilities Demand section. Proposed in an effort to start standardizing the definition of off-peak periods with in the Company. Current language introduces undefined days into the billing process. >Add FAC Section to tariff. Make FAC applicable to the rate.
17	Large General Service - All Electric LGA 19A, 19B, 19C, & 19D	>Proposed rate design changes. >Add rate codes to tariff. >Remove special facilities demand language. >Remove excess language from Facilities Demand section. >Add FAC section to tariff.	>Add the rate codes used in billing to the tariff sheets. >Code STHE is frozen and no longer used in this tariff. Proposing removal. > Remove "or any day celebrated as such." from the end of the Facilities Demand section. Proposed in an effort to start standardizing the definition of off-peak periods with in the Company. Current language introduces undefined days into the billing process. >Add FAC Section to tariff. Make FAC applicable to the rate.

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1	**Proposed Tariff and Rule Revisions for 2015 KCP&L-MO Rate Case**		
2	**Rates**	**Proposed Change**	**Support/Additional Detail**
18	Two Part - Time Of Use TPP 20, 20A, 20B, 20C, & 20D	>Propose availability be frozen. >Add FAC section to tariff.	>Current Time of Use rates are not properly designed, resulting in little customer participation and questionable benefit to the Company. Rate redesign is planned. > Remove "or any day celebrated as such." from the end of the Facilities Demand section. Proposed in an effort to start standardizing the definition of off-peak periods with in the Company. Current language introduces undefined days into the billing process.
19	Special Interruptible Contracts SIC 23	Reserve tariff page for future use	>Tariff specific to two contracts. Contracts are expired. No customer or revenue impacts.
20	Reserved Sheets 24A, 24B	Propose elimination of the tariff.	Unused sub-pages. Proposing removal to clean up tariff book.
21	Real-Time Pricing RTP 25, 25A, 25B, 25C, & 25D	>Propose availability be frozen. >Add FAC section to tariff.	>Current Real Time Pricing rates are not properly designed, resulting in little customer participation and questionable benefit to the Company. Rate redesign is planned. >Add FAC Section to tariff. Make FAC applicable to the rate.
22	Real-Time Pricing - Plus RTP-Plus 26, 26A, 26B, 26C, & 26D	>Propose availability be frozen. >Add FAC section to tariff.	>Current Real Time Pricing rates are not properly designed, resulting in little customer participation and questionable benefit to the Company. Rate redesign is planned. >Add FAC Section to tariff. Make FAC applicable to the rate.
23	Standby or Breakdown Service (Frozen) 1-SA 30 & 30A	Propose elimination of the tariff.	Tariff availability currently frozen. No customers on the rate. Rate no longer needed. No customer or revenue impacts.
24	Private Unmetered Protective Lighting Service AL 33 & 33B	>Proposed rate design changes. >Add FAC section to tariff. >Add kWh information to each light.	>Add FAC Section to tariff. Make FAC applicable to the rate. >Add annual monthly average kWh data to each light on the tariff. Associated with proposed FAC. Allow customers to calculate usage for the lights.
25	Municipal Street Lighting Service ML 35, 35A, 35B, 35C, and 35D	>Proposed rate design changes. >Add FAC section to tariff. >Add kWh information to each light. >Eliminate Reserved Sheet 35D. >Propose elimination of unused options.	>Add FAC Section to tariff. Make FAC applicable to the rate. >Add annual monthly average kWh data to each light on the tariff. Associated with proposed FAC. Allow customers to calculate usage for the lights. >Unused sub-pages. Proposing removal to clean up tariff book. >Remove Code TTCX as it is frozen, is not installed, and is not needed.
26	Municipal Street Lighting Service ML 36, 36A, & 36B,	>Proposed rate design changes. >Add FAC section to tariff. >Add kWh information to each light. >Propose elimination of unused options.	>Add FAC Section to tariff. Make FAC applicable to the rate. >Add annual monthly average kWh data to each light on the tariff. Associated with proposed FAC. Allow customers to calculate usage for the lights. >Sections 4.2 and 4.3 are obsolete and not longer used by the Company. No customer of revenue impact.

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1	**Proposed Tariff and Rule Revisions for 2015 KCP&L-MO Rate Case**		
2	**Rates**	**Proposed Change**	**Support/Additional Detail**
27	Municipal Traffic Control Signal Service TR 37, 37A, 37B, 37C, 37D, 37E, 37F& 37G	>Proposed rate design changes. >Add FAC section to tariff. >Add kWh information to each light. >Propose elimination of unused options.	>Add FAC Section to tariff. Make FAC applicable to the rate. >Add annual monthly average kWh data to each light on the tariff. Associated with proposed FAC. Allow customers to calculate usage for the lights. >Remove Basic Installations (2) and (5). Remove Supplemental Equipment (1), (2), (3), (10), (16), and (17). Sections are obsolete and not longer used by the Company. No customer of revenue impact.
28	Special Contracts - Customer Specific 39, 39A, 39B, 39C, 39D, 39E, 39F, 39G, 39H, 39I, 39J, 39K, 39L, 39M, 39N, & 39O	>Reserve tariff page for future use >Propose elimination of unused tariff sub-pages.	>Tariff specific to two contracts associated with the Comprehensive Energy Plan. Contracts are expired. No customer or revenue impacts.
29	Reserved Sheets 40A, 40B, 40C, 40D, 40E, 40F, 40G, & 40H	Propose elimination of the tariff.	Unused sub-pages. Proposing removal to clean up tariff book.
30	Company Employee Merchandise & Equipment Purchase Program 43C	Propose elimination of the tariff.	The program is inactive and all loans associated with the program have been repaid. No customer or revenue impacts.
31	Reserved Sheets 43A, 43B, 43D, 43E, 43E.1, 43F, 43G, 43H, 43I, 43I.1, 43I.2, 43J, 43K, 43L, 43M, 43N, 43O, 43P, 43Q, 43R, 43S, 43T, 43U, 43V, 43W, 43X, & 43Y	Propose elimination of the tariff.	Unused sub-pages. Proposing removal to clean up tariff book.
32	Economic Relief Pilot Program 43Z, 43Z.2	>Propose expansion of the program. >Propose changing the recipient of program unsent funds.	Increase participant limit from 1,000 to 1,500. Increase credit from up to $50 per month to up to $65 per month. >Directing unspent funds to the Dollar-Aide program is more consistent with the ERPP purpose than directing toward DSM accounts.
33	Reserved Sheets 43AI & 43AJ	Propose elimination of the tariff.	Unused sub-pages. Proposing removal to clean up tariff book.
34	Promotional Practices VARIANCES 44	Reserve tariff page for future use	Variance related to specific customer. Customer has changed and is not longer qualified for the variance. No customer or revenue impact.
35	Off-Peak Lighting Service 45	>Proposed rate design changes. >Add FAC section to tariff.	>Add FAC Section to tariff. Make FAC applicable to the rate.
36	LED Pilot Program 48A & 48B	>Proposed rate design changes. >Add FAC section to tariff. >Add kWh information to each light.	>Add FAC Section to tariff. Make FAC applicable to the rate. >Add annual monthly average kWh data to each light on the tariff. Associated with proposed FAC. Allow customers to calculate usage for the lights
37	Fuel Adjustment Clause 50	NEW TARIFF	See testimony for more complete justification.
38			

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1	**Proposed Tariff and Rule Revisions for 2015 KCP&L-MO Rate Case**		
2	**Rates**	**Proposed Change**	**Support/Additional Detail**
39	**Rules & Regulations**	**Proposed Change**	**Status**
40	Table of Contents 1.01, 1.02, 1.03, 1.04, 1.04A, & 1.04B	Update to reflect tariff eliminations and additions.	
41	1. DEFINITIONS		
42	.05 Rural Customer 1.05	Propose removing "Rural Service" language.	Rural Service is not longer uniquely applied in our rates or processes.
43			
44	2. SERVICE AGREEMENTS		
45	.01 Application for Service 1.07A	Correct spelling in title	
46	.07 Credit Regulations 1.09	Propose changing number of delinquent bills from three to two for deposit requirement. 2.07A(2)	Change is being proposed to bring KCP&L-MO tariffs in line with current GMO tariffs. Changing threshold for deposits will better protect the Company from default and will make internal processes more efficient. Additionally, the proposed change would allow delinquency to include payment methods other than checks.
47			
48	6. METERING		
49	.09 Billing Adjustments 1.24 & 1.24a, & 1.24b	>Propose language to allow back billing for slow meters for up to 12 billing periods. Currently, no back bill allowed. (Will match GMO)(6.09b) >Propose adding provision to allow back billing up to 60 months for non-residential customers (6.09c)(6.09d)(6.09e) >Propose removing reference to "Rural Residence" (6.09f)	>Changes are being proposed to bring KCP&L-MO tariffs in line with current GMO tariffs. Consistent adjustment terms will provide customers consistent treatment and will make internal processes more efficient. >Rural Service is not longer uniquely applied in our rates or processes.
50			
51	8. BILLING AND PAYMENT		
52	.07 Return Check Charge 1.28	Propose language to make consistent between jurisdictions and address charges associated with other non-check, forms of payment.	>Changes are being proposed to bring KCP&L-MO tariffs in line with current GMO tariffs. Consistent adjustment terms will provide customers consistent treatment and will make internal processes more efficient.
53	.08 Collection Charge 1.28	Propose increasing the collection charge to $25 (currently $20)	>Changes are being proposed to bring KCP&L-MO tariffs in line with current GMO tariffs. Consistent adjustment terms will provide customers consistent treatment and will make internal processes more efficient. Expected revenue impact is $22,575. Revenues are part of Misc. Revenue (Account 451) and will be adjusted accordingly.
54	.09 Pre-MEEIA Charge 1.28	Propose updated Pre-MEEIA charge.	According to prior agreements, the pre-MEEIA charge is updated to reflect DSM costs embedded in the proposed rate.
55			
56	9. EXTENSION POLICY		
57	.01 Overhead Single-Phase Residential and Rural Residential Extensions 1.31	Propose removing reference to "Rural Residence"	Rural Service is not longer uniquely applied in our rates or processes.
58	.02 Other Extensions 1.32	Propose removing reference to "Rural Residence"	Rural Service is not longer uniquely applied in our rates or processes.
59			
60	12. AGREEMENTS		
61	.01 Service Agreement	Propose removal of legacy form.	Legacy, hard copy forms are no longer used. Revise tariff to allow flexibility for agreements.
62	.02 Indemnity Bond	Propose removal of legacy form.	Legacy, hard copy forms are no longer used. Revise tariff to allow flexibility for agreements.
63			

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1	**Proposed Tariff and Rule Revisions for 2015 KCP&L-MO Rate Case**		
2	**Rates**	**Proposed Change**	**Support/Additional Detail**
64	19. AVERAGE PAYMENT PLAN	Propose adding language from GMO concerning adjustment.	Changes are being proposed to bring KCP&L-MO tariffs in line with current GMO tariffs. Consistent adjustment terms will provide customers consistent treatment and will make internal processes more efficient.
65			
66	20. PROMOTIONAL PRACTICE WAIVERS		
67	.01 Farmland Industries Thermal Storage Project 1.70	Reserve tariff page for future use	Related to Promotional Practice Variance, Sheet 44. Associated with specific customer. Customer has changed and is not longer qualified for the waiver. No customer or revenue impact.
68			