Exhibit No.:	
Issue:	Fuel Adjustment Clause; Transmission Costs; Property Taxes; Critical Infrastructure Protection; Renewable Energy Standard Costs; Pre-MEEIA Opt Out Cost Recovery; Electric Vehicle Charging Station Tariff, Other Tariff Changes
Witness:	Tim M. Rush
Type of Exhibit:	Direct Testimony
Sponsoring Party:	Kansas City Power & Light Company
Case No.:	ER-2016-0285
Date Testimony Prepared:	July 1, 2016

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO.: ER-2016-0285

DIRECT TESTIMONY

OF

TIM M. RUSH

ON BEHALF OF

KANSAS CITY POWER & LIGHT COMPANY

Kansas City, Missouri
July 2016

Certain Schedules Attached To This Testimony Designated "(HC)" Contain Highly Confidential Information. All Such Information Should Be Treated Confidentially Pursuant To 4 CSR 240-2.135.

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DIRECT TESTIMONY

OF

TIM M. RUSH

Case No. ER-2016-0285

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: On whose behalf are you testifying?

A: I am testifying on behalf of KCP&L.

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 the challenges and risks facing the Company;

II. Address the Company's request to continue the Fuel Adjustment Clause ("FAC") and changes to the FAC tariff, including recovery of SPP transmission costs and, to the extent transmission costs are not included in the FAC, the combined use of forecasted transmission costs and a one-way tracker for such costs;

III. Explain and support the Company's request to set property tax expense using forecasted information and, in conjunction with that, the use of a one-way tracker;

IV. Explain and support the Company's use of forecasted expenses combined with a one-way tracker mechanism to recover operations and maintenance ("O&M") expenses to comply with Federal Energy Regulatory Commission ("FERC") critical infrastructure protection ("CIP") and cybersecurity costs;

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

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

VII. Recommended rates for Electric Vehicle Charging Stations.

I. 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 certain billing determinants that drive revenues (i.e., per customer 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. However, recently, the Commission established a plan in the KCP&L Greater Missouri Operations Company (GMO) rate case to complete the rate case in 10 months. It would be KCP&L's hope that the Commission would follow that plan in this case. KCP&L's costs have been increasing rapidly since the conclusion of its last rate case and are expected to continue rising, particularly with increases in property taxes, transmission costs and CIP/Cybersecurity expenses. These expenses are essentially out of the control of the Company. The Company implemented a Fuel Adjustment Clause (FAC) in its last rate case that has substantially helped with the regulatory lag associated with fuel costs. However, due to continued increases in costs outside of the Company's control and the shrinking of rate revenues, KCP&L has experienced lower earnings than authorized.

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

A: Yes. The implementation of the FAC in the last rate case was very important to help relieve part of the lag that has existed. While the Company initially requested inclusion of transmission costs and revenues in the FAC, the Commission denied this in its Report and Order. Continuation of the FAC is critical to helping relieve lag, but changes to the FAC are necessary for KCP&L to have a reasonable opportunity to achieve its authorized return on equity.

In this case, the Company is 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. Specifically, the Company is asking for continuation of the FAC with inclusion of both forecasted transmission expenses and revenues. It is asking for forecasted property taxes and CIP/Cybersecurity costs. If the projected expense level included in rates turns out to be less than actuals, the Company would absorb the difference. If the projected expense levels included in rates turned out to be higher than actuals, the Company would credit to customers the difference in the next rate case. Each of these adjustments will be addressed later in my testimony.

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

A: Fuel, purchased power, transmission costs, transmission revenues, off-system sales and property taxes are costs and even the CIP/Cybersecurity costs are largely beyond the Company's control and are areas where we are facing significant expense increases over the next several years. Without an adequate mechanism to timely recover these increases, KCP&L will not have a reasonable opportunity to earn its authorized return on equity now or in the foreseeable future.

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.

II. FUEL ADJUSTMENT CLAUSE

Q: Does the Company currently have an approved FAC?

A: Yes. The FAC was initially approved in Case No. ER-2014-0370 on September 2, 2015, and rates went into effect on September 29th. The Company recently completed its first partial accumulation period of September 29, 2015 through December 31, 2015. The Commission has approved the tariff change. The recovery of the first accumulation period began in April 2016 and will run through March 2017.

Q: What are the rules for continuing an FAC?

A: The requirements for continuing an FAC are found in Section 386.266 RSMo and Commission Rules 4 CSR 240-20.090 and 4 CSR 240-3.161(3)(A) through (T). The supporting information is summarized in the attached Schedules TMR-1 through TMR-4.

Q: Has the Company met all the filing requirements to continue the FAC in 4 CSR 240-20.090?

A: Yes.

Q: Is the Company requesting to continue the FAC?

A: Yes. The Company is requesting to continue the FAC which applies to fuel and purchased power expenses, including a credit for off-system sales revenues. The Company is also proposing to include 100% of both transmission expense and revenues associated with Southwest Power Pool (SPP) and fuel handling expense.

Q: Why is the Company requesting a continuation of the FAC?

A; The Company is requesting to continue the FAC to address continuing uncertainty and volatility in fuel, purchased power and transmission costs offset by revenues as well as increases in costs that are expected to continue. 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: Does the FAC help both customers and Company?

A: Yes. The FAC is a balanced recovery mechanism which provides the Company with recovery of the majority of its fuel, purchased power and transportation costs with off system sales and transmission revenues above a base amount that is included in base rates. The FAC provides customers assurance that KCP&L is not over-recovering net-fuel and purchased power costs, and to ensure the Company has an opportunity to earn a fair return in order to generally preserve the financial health of the Company.

Q: Is the Company proposing to change the base amounts included in the tariff?

A: Yes, the Company is proposing to re-base the FAC to reflect current fuel and fuel handling (other than internal labor), purchased power and off-system sales and also to include the transmission costs and revenues by and for others along with the fees associated with belonging to SPP. The transmission of electricity by and for others as well as the associated SPP fees reflected in this filing are for forecasted expenses out over 2017 and 2018. I am also proposing to include three levels of FAC rates based on the Company's current loss study. This would reflect customers on secondary, primary and transmission/substation level service. Currently, we reflect only secondary and primary losses in the FAC rate.

Q: What are non-internal labor fuel handling expenses?

A: These are expenses for goods or services excluding internal labor used by the Company to purchase or acquire fuel or fuel transportation, including forecasts, market analyses or information, strategy development and contract or issue negotiation, to manage fuel purchases, including contract administration, monitoring and analyzing fuel quality, to manage fuel inventories, including measuring and establishing volume levels, to handle or move fuel from shipping facility to first bunker, hopper, bucket, tank, or holder of boiler house structure, or to handle, pump, or move fuel during or after receiving, including scheduling transportation, moving fuel in storage and transferring from one station to another.

Q: Why are you including fuel handling expenses?

A: There are two reasons why these costs are included. First, the purpose of the forecasts, market analyses or information, strategy development and contract or issue negotiation expenses is to guide us in our pursuit of better contract terms or lower cost of fuel and fuel transportation. The benefits or cost savings from purchasing those goods or services are reflected in the cost of fuel included in the FAC. Likewise, the benefits of managing fuel purchases are reflected in the effective cost of fuel included in the FAC. Second, non-labor fuel handling costs are related to the volume of fuel we purchase. That is, the less fuel we buy, the lower our non-labor fuel handling expenses.

Q: What is the re-base amount reflected in this rate case?

A: The re-base amount is $0.01987 per kWh.

III. TRANSMISSION COSTS

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

A: The Company requests that all 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 to KCP&L. Transmission costs incurred for the operation of KCP&L transmission systems will not be included in the FAC, but will be recovered through base rates. The adjustment in this case reflects inclusion of the projected transmission costs for the average of 2017 and 2018. To the extent the Commission rejects inclusion of any portion of SPP transmission costs in the FAC, then in the alternative, the Company requests inclusion of the projected transmission costs and revenues for the average of 2017 and 2018, be included in base rates. If the actual costs are less than forecasted expense levels included in rates, then the difference will be credited to customers in the next rate case. If the actuals are greater than the amount in rates, then the Company would absorb the excess costs.

A. History of Transmission Costs

ER-2014-0370 – In the Company's last rate case, the Company requested inclusion of the transmission costs and revenues in the proposed FAC. It further requested in the alternative, to reflect forecasted transmission costs in an asymmetrical tracker that would allow recovery of the forecasted transmission expenses and revenues at a set amount. If the actual costs were less than those included in rates, the difference would be credited to customers in the next rate case. If the actuals were greater than those reflected in rates, then the Company would absorb the excess costs. Both positions were rejected in that case and the inclusion of transmission expenses and revenues is currently on appeal.

ER-2012-0174 - In the case prior to its last rate case, 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.

EU-2014-0077 - As a result of the Order in that case, 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. 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.

As can be seen, recovery of KCP&L transmission costs either through a tracker or reflected in the FAC has had quite a history before this Commission.

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

A: As I testified in the last rate case, transmission costs are directly linked to the Company's fuel and purchased power requirements, particularly because of the SPP Integrated Marketplace ("SPP IM"), also called the Day Ahead market. Transmission costs have been increasing and can vary significantly from year-to-year, and such costs are a material cost of service component. These significant transmission cost increases and fluctuations are incurred both in serving native customers in the service territory and in off-system sales. The primary drivers of the increases are the costs associated with SPP's regional transmission upgrade projects that are part of its transmission expansion plans, which have increased KCP&L's costs significantly and will continue to increase costs when rates set in this case will be in effect.

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 include the need to reduce congestion on key transmission paths in order to facilitate more efficient power markets and investments to improve transmission reliability. The SPP-allocated transmission costs are billed to the Company pursuant to a FERC-approved tariff; as such the Company has no ability to avoid paying these SPP-allocated transmission costs.

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. Company witness John Carlson addresses the SPP market and the historical costs and the anticipated increases in transmission costs in the future.

Q: What transmission costs, specifically, is KCP&L proposing 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 R-82 (Transmission of Electricity for Others), CS-45 (Transmission of Electricity by Others), CS-85 (Regulatory Assessments- Schedule 12 Fees) and CS-86 (Schedule 1-A Fees).

IV. 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.

V. PROPERTY TAXES

Q: What is the Company proposing with regard to property taxes?

A: KCP&L is requesting recovery of projected property taxes in this case. The Company has included projected property taxes reflective of the average of 2017 and 2018.

Q: Is the proposal a tracker?

A: Somewhat. We are proposing to set the baseline expense amount in rates by use of projected expenses for 2017 and 2018 and then use an asymmetrical or one-way tracker to protect customers in the event future property taxes are lower than the projected amount included in rates. It is asymmetrical in that the Company will return to customers in the next rate case if the amount included in rates is greater than the actual property tax expenses. However, if actual property taxes exceed the allowance in rates, the Company will absorb those excess expenses.

Q: Why is the Company's proposal appropriate for KCP&L's property tax expenses?

A: Property tax is one of the primary drivers in this rate case and is expected to increase steadily when rates set in this case will be in effect. The Company is requesting projected property tax expense to help address these expected increases.

Property tax expenses have been escalating over the 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 paying for property tax in excess ofamounts 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 the property tax mechanism be implemented?

A: The Company proposes to establish the level of property taxes in this case based on the average of projected 2017 and 2018 costs. 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 recovery treated as a regulatory liability (Account 254). When the Company files its next rate case, any amount recorded in account 254 is an over-collection of the Missouri portion of property taxes, and the Company will make an adjustment to return that amount back to customers. We propose that the regulatory liability be amortized to cost of service in the Company's next rate proceeding over the same length of time that the over-collections were accumulated. On the other-hand, if the Company has under-recovered the Missouri portion of property taxes, then the Company will absorb those excess costs.

Q: Is the 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 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.

VI. CRITICAL INFRASTRUCTURE PROTECTION/CYBERSECURITY("CIP")

Q: What is the Company requesting in this case as it pertains to CIP?

A: The Company is requesting recovery of projected CIP costs based on the average of expected 2017 and 2018 O&M expenses.

Q: Is this a tracker?

A: Similar to the proposed property tax recovery mechanism, KCP&L is requesting recovery of projected CIP costs based on an average of projected 2017 and 2018 costs. It is a tracker in that this will become the base-line in which we will measure actual CIP costs. The Company would then track its actual CIP expenses against this amount, with the Missouri jurisdictional portion of any excess recovery treated as a regulatory liability (Account 254). When the Company files its next rate case, any amount recorded in account 254 is an over-collection of the Missouri portion of CIP expense, and the Company will make an adjustment to return that amount back to customers. We propose that the regulatory liability be amortized to cost of service in the Company's next rate proceeding over the same length of time as costs were accumulated. On the other-hand, if the Company has under-recovered the Missouri portion of CIP expenses, then the Company will absorb those excess costs.

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-88. Also, Company witness Joshua Roper addresses in detail the CIP program and both actual and projected program costs.

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

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

VII. 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 up to 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.

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 is requesting recovery of 1% of the revenue level established in its last rate case, Case No. ER-2014-0370. Based on the ordered revenues, we have included $8,520,276 in this case. The projected balance in this RES account at December of 2016 is $28,526,998. As described in the testimony of Ronald A. Klote, the Company had previously included the RES cost amortization authorized respectively in the 2012 Case (Vintage 1) and the 2014 Case (Vintage 2). Vintage 1 amortization ended January 2016.

Per the Partial Non-Unanimous Stipulation and Agreement to Certain Issues in Rate Case ER-2014-0370, KCP&L has applied prospective tracking to this amortization by moving the amortization to impact the balance in Vintage 2. The remaining balance of Vintage 2 plus all of the RES compliance costs incurred since then (Vintage 3) are in a deferred account. The unrecovered amount is not included in rate base.

Q: Is the 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-116 (Renewable Energy Standards).

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

A: In case ET-2014-0071 the Commission approved a Non-Unanimous Stipulation and Agreement whereby KCP&L agreed that it 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[1] 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.

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

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.

As a result of Section C, KCP&L has only requested 1% of the revenues as recovery of its RES costs.

VIII. 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. In that case, the Commission authorized KCP&L to implement a DSIM rider for recovery of costs going forward. KCP&L has been offering Demand-Side Management ("DSM") programs prior to MEEIA since 2005 (Pre-MEEIA). Pre-MEEIA DSM costs have been deferred with recovery afforded by inclusion of an amortization amount in the revenue requirement calculations of KCP&L's rate cases. Each rate case established a new vintage of costs to be recovered. Vintages 1 through 4 are being amortized over ten years. Vintages 5 and 6 are being amortized over six years. The Company is proposing that vintage 7, which will be established in this current case, also be amortized over six years. Vintage 7 reflects the period June 1, 2015 through December 31, 2016.

Q: What pre-MEEIA expenditures are being included for recovery in this case?

A: Since the May 2015 true-up in KCP&L's last rate case, Case No. ER-2014-0370, KCP&L has incurred $1,468,282 in additional pre-MEEIA expenditures including carrying costs from June 2015 projected to December 2016.

Q: Is the 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-100 (DSM Programs).

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.

Q: Has the pre-MEEIA opt-out rate been updated for this filing.

A: Yes, the Company has recalculated the pre-MEEIA opt-out rate resulting in a rate of $0.00158/kWh. The calculation of the rate is included in my supporting workpapers filed in this case.

Q: Please explain how the adjustment is applied.

A: First, in accordance with the opt-out procedures specified in Commission Rule 4 CSR 240-20.094(6) a customer may express their desire to not be charged for demand-side recovery. Once the opt-out request period ends and the customers are confirmed, the Company determines the pre-MEEIA lost recovery associated with the opt-out customers. It is a simple calculation where the amount of pre-MEEIA costs included in the Company's revenue requirement is divided by the non-lighting kWh to define a per kWh rate. This per kWh rate is applied to the test year energy associated with the opt-out customers. The resulting revenue amount is divided between the non-residential, non-lighting classes and added to the revenue requirement for the class. For this filing, the pre-MEEIA rate was determined to be $0.00158 per kWh based on the pre-MEEIA amortization and return amount of $13,065,727 and a total kWh of 8,280,335,384. With 828,350,433 kWh of energy associated with opt-out customers, the lost recovery amount to be collected from other customers is $51,483.

IX. ELECTRIC VEHICLE TARIFF

Q: Are you proposing a new tariff to address the Electric Vehicle charging stations that the Company has installed throughout its Missouri service territory.

A: Yes. I will (a) explain the Company's proposed new tariff for electric vehicle ("EV") charging stations resulting from KCP&L's Clean Charge Network ("CCN") program; (b) discuss the Company's request regarding cost recovery for this program; and (c) address the regulatory policy issues related to KCP&L's CCN.

Q: Before you explain the proposed tariff, what is the CCN program?

A: KCP&L and KCP&L Greater Missouri Operations Company ("GMO") have launched an initiative to install and operate more than 1,000 EV charging stations throughout the Greater Kansas City region within the KCP&L (both Missouri and Kansas) and GMO service territories.

A. Proposed Tariff

Q: Please describe the purpose of the tariff?

A: Schedule TMR-5 presents the proposed new tariff titled Public Electric Vehicle Charging Station Service, also referred to as Schedule CCN. The tariff is designed to address the new mobile customer electric needs within our service territory. It is specific to KCP&L-owned charging stations available to the public throughout its Missouri service territory. The proposed tariff does not address charging of EVs at customer single-family residences or at privately owned and operated charging stations like some businesses have provided at their sites specifically for their employees and guests. The CCN is designed to address the Company's service territories and to service KCP&L's mobile customers when they are in KCP&L's certificated territory.

Q: How is the CCN system designed to accommodate multiple users of the charging stations?

A: The charging stations are designed with internal meters to allow measurement of usage for each EV charging session. The user must set up an account with ChargePoint, the Company's third party vendor, and ChargePoint will provide them with a unique access card to use at any of the KCP&L charging stations.

Q: Does a customer need to sign up with KCP&L to qualify for the charging station tariff?

A: Customers must sign up for an account through KCP&L's third party vendor, ChargePoint, to be able to access the charging stations.

Q: How is the tariff designed?

A: The Schedule CCN rate for a Level 2 Charging Station is a kWh charge based on the average price per kWh for residential class, including energy and customer charges. The rate for a Level 3 Charging Station (otherwise known as a DC Fast Charger) is a kWh charge based on the average price per kWh for the small general service class, including energy, demand and customer charges. In addition to the energy charge, the Fuel Adjustment Charge (FAC), and Demand Side Investment Mechanism (DSIM) – will also be added onto the charge along with applicable taxes. The applicable $/kWh factors for each of these riders will be added to the applicable energy charge from Schedule CCN and will be shown as a single all-in $/kWh rate on the charging station screen. Taxes and fees are applied separately at the completion of the session.

In addition to the Energy Charge rates, the tariff also includes guidelines for application of Session Charges, at the discretion of the host, to incent charging station users to move their vehicles promptly after charging to improve utilization of the stations.

Q: Does the tariff recover costs related to the charging stations solely from the users of the charging stations?

A: Yes, The tariff recovers from the users an amount above the incremental fuel costs and provides a contribution to recovering the fixed and variable costs of supplying energy to the charging stations.

Q: What is the expected cost for a customer to charge their vehicle?

A: That depends on several things: (a) which payment option the host chooses for the charging stations at its site; (b) which type of charging station the customer uses; and (c) the city/county location of the charging station. I will discuss each of these in turn.

First, the host may choose one of two payment options for charging stations located on their site. The first option provides for the host to pay the electricity costs associated with customer usage, the Energy Charges plus riders and taxes, while the customer pays any Session Charges. KCP&L has had a number of hosts indicate that they plan to continue to pay for the station usage even after their two-year commitment expires. The second option provides for the customer to pay the Energy Charges, plus riders, surcharges and taxes, and any Session Charges. So, the payment option chosen by the host will affect what the customer will pay to use the charging stations at each site.

Second, as noted earlier, there are two levels of chargers being installed – Level 2 and Level 3. The Level 3 charging stations allow for quicker charging than the Level 2 charging stations. The cost per kWh will depend on the type of charging station the customer uses to charge their vehicle as discussed in more detail below. Generally speaking, the cost per kWh is greater for the Level 3 charging station.

Finally, as taxes and fees, including franchise fees, sales tax, etc. apply to the charges for using a charging station, the location of the charging station will determine which fees and taxes apply.

Q: How did KCP&L determine the kWh rates set forth in Schedule CCN?

A: As stated above, the kWh rates set forth in Schedule CCN are based on KCP&L's average price for the residential class for a Level 2 charging stating and the Small General Service average price for a Level 3 charging station.

Q: Why did KCP&L propose a different rate for Level 2 and Level 3 Charging Stations?

A: The differing charging abilities of Level 2 and Level 3 charging stations present different challenges to the KCP&L system. Specifically, the more energy a charging station is able to provide in a given period, the more demand that the charging station puts on the local distribution infrastructure.

Based on charging capabilities, the Level 2 charging stations have approximately the same effect on the local infrastructure as a residential customer. Therefore, the Company based the Level 2 charging station rate on its average price for the residential class. The Level 3 charging stations have a larger draw on the local infrastructure and could be compared to a small general service customer. Therefore, the Company based the Level 3 charging station rate on its average price for the small general service class.

Q: How do these prices compare to the cost of filling up a gasoline-powered car with gas at a gas station?

A: The Electric Power Research Institute ("EPRI") undertook a study entitled *Preliminary Scoping Analysis of the Effects of Transportation Electrification in the KCP&L Service Territory,* ("EPRI Study")[2]. The EPRI Study addresses the comparison between EV charging and gasoline-powered vehicles. Assuming an EV travels 3.3 miles per kWh of

[2] *Preliminary Scoping Analysis of the Effects of Transportation Electrification in the KCP&L Service Territory,* Electric Power Research Institute (EPRI), June 24, 2016.

energy consumed, the cost to charge an EV at a KCP&L charging station using the proposed rates, not including taxes and fees, would equate to filling up a traditional gasoline-powered vehicle rated at 33 MPG with gas priced from $1.42 to $1.53 per gallon.

For example, a Ford Focus Electric contains 23 kWh of battery storage and has a range of 76 miles. Based on the charges contained in the proposed Schedule CCN, the approximate costs to charge would be $2.99 without taxes and fees applied. The Ford Focus S, a similar vehicle but with a combustion engine, has a gas mileage of 30 miles per gallon. The cost to travel the same 76 miles, utilizing EPRI's 10-year gas price average of $3.00 per gallon, would be $7.60.

Q: Does the host receive compensation for locating a charging station(s) on its premise?

A: No. The host does not receive any monetary compensation for hosting a charging station(s). Generally, the host uses the EV charging facility as a draw to get customers to visit its place of business, or cater to existing customers, and does not expect additional revenues related directly to the operation of the charging station. Some hosts may choose to continue to pay the costs associated with customer usage of the charging station as a customer convenience and/or to increase the incentive for customers to visit their business or property.

Q: Does the Session Charge under Schedule CCN applicable at the discretion of the host provide revenue to the host?

A: No. Any Session Charges collected are recovered by the Company to be used to offset costs associated with the EV Charging Station infrastructure and to offset undepreciated rate base. .

Q: Why would a host impose Session Charges on users of the charging stations at its site?

A: The host has the discretion under Schedule CCN to impose a Session Charge to incent customers to move their vehicles once the charging process is completed so that other customers can have access to the facilities. This charge is at the discretion of the host, within parameters set by KCP&L and the tariff. The Session Charges may be tiered to apply differently to the first part of a charging session and increased at a later point in the charging session. For example, a host may choose to apply no Session Charge for the first two hours of a charging session but apply a $2.00 per hour Session Charge for each hour of the session that exceeds two hours. A host may also choose to apply no Session Charges at all or to apply Session Charges for the entire charging session.

Q: How does KCP&L intend to control the level of Session Charges a host may apply?

A: Schedule CCN sets a cap of $6.00 per hour for Session Charges to ensure they are not set so high that they discourage customers from using the stations. A host may not exceed this rate. Additionally, a host may not apply more than two tiers of Session Charges to a charging station.

Q: How did KCP&L determine the range of Session Charges set forth in Schedule CCN?

A: KCP&L set the maximum of the range of Session Charges, $6.00 per hour, based on the maximum rate of charge provided by the Level 3 charging station – the fastest charger. A Level 3 charging station can charge at a rate of up to 40 kW per hour. At an estimated rate of $0.15/kWh, a full hour of charging on a Level 3 station would cost $6.00.

Q: When does KCP&L propose the tariff, Schedule CCN, become effective?

A: The tariff is designed to take effect with the implementation of rates in this case. The hosts for each charging station agreed to pay for the electricity usage for charging stations at the host's site for the first two years of the agreement. The implementation of this rate will closely correspond to the completion of the two year commitment. KCP&L anticipates that all host sites would move to the tariff once it becomes effective, regardless of when the agreement was executed to allow for a full and consistent transfer to the Schedule CCN rates.

Q: Does KCP&L propose any reporting related to the Schedule CCN tariff?

A: Yes. The Company intends to work with Staff of the Commission to establish reporting on the charging stations. KCP&L proposes that such report would include information on charging station usage and revenue.

B. Cost and Cost Recovery

Q: What is the expected cost for the CCN deployment planned by KCP&L?

A: The total budgeted capital cost for the project is $16.6 million of which, based upon the service territory deployment plan, approximately $6 million would represent the budgeted investment in the Company's Missouri jurisdiction as the result of situs based allocators. In addition to these costs, KCP&L anticipates total Company annual operations and maintenance ("O&M") expense of roughly $250,000 which will be allocated to the Company's Missouri jurisdiction.

Q: Will Commission approval of the CCN program and related tariff provide KCP&L the opportunity to continue to add charging stations beyond those currently envisioned?

A: No. The CCN project involves just over 1,000 charging stations throughout KCP&L's service territories. The actual number of charging stations located in Missouri will be determined, in part, by host interest. KCP&L included a cap in Schedule CCN of 400 charging stations with Commission approval required for additional stations under the tariff.

Q: Are these costs currently included in KCP&L's rates?

A: No. The costs for the charging stations and associated O&M were not included in KCP&L's most recent rate case.

Q: Is KCP&L requesting these costs be included in base rates as part of this case?

A: Yes. KCP&L is asking for Commission approval to include the Missouri jurisdictional share of the costs, both capital and O&M, of its CCN program in base rates as part of this case. Any off-setting tax credit would be a reduction to revenue requirement.

Q: Do you believe that the cost recovery mechanisms and resulting rates proposed by KCP&L in this application are fair, just and reasonable for KCP&L's Missouri customers?

A: Yes, I do.

Q: What about customers who do not own an EV and will never use the charging stations?

A: All of KCP&L's customers, both EV users and non-EV users alike, will benefit from the Company's EV CCN project. Benefits include increased off-peak electricity usage, environmental benefits from reduced CO_2 emissions and lower ozone-reducing pollutants, economic impacts resulting in job creation, improved customer programs, and lower costs and efficiency by having the utility install, own and operate the EV charging stations. The increase in home-based usage to charge EVs will also provide a broader base over which to spread system costs.

Q: Why is it fair to include the cost of this project in revenue requirement and rates to be paid by KCP&L's customers?

A: First, aside from the electricity used at the EV charging stations (paid for by either the host sites, in the case of Level 2 charging stations, or Nissan, in the case of Level 3 charging stations), it needs to be remembered that KCP&L shareholders have borne 100% of the costs of the CCN program to date as no costs associated with CCN have been included in rates paid by the Company's Missouri customers. We are asking for the ability to recover all of the costs of the project from customers, but that does not shift 100% of the risk of this program onto customers. KCP&L must construct and operate the facilities prudently or risk disallowances, just like other investments by the Company in generation and distribution facilities. It is the obligation of KCP&L to market and promote the facilities to help achieve their acceptance and growth. KCP&L has risk, and we have the incentive to make this program successful.

There is no basis for treating this investment different from other investments incurred to allow the Company to provide efficient service to our customers. These facilities are part of the KCP&L system; they are infrastructure, not an end-use product. The investment is necessary to provide electric energy to our mobile customers and should be recovered as other prudent investments are recovered.

X. RATEMAKING QUESTIONS

Q: What is the impact of the charging stations on KCP&L's retail customers?

A: After consideration of the alternative refueling property tax credit and deferred taxes, a simple look at the capital, depreciation and O&M costs, without consideration of the other CCN benefits mentioned above, would result in an annual revenue requirement of approximately $16,434.

Q: What is the impact of the EV charging stations on the Company's distribution system?

A: The EPRI Study that I cited earlier in my testimony also addresses this question as it contains an analysis of the impacts of the CCN project on KCP&L's distribution system. Generally speaking, EPRI found that the Company's system is robust enough to handle the increased usage anticipated from the CCN project. Additionally, the CCN being designed and installed by KCP&L where the stations can be efficiently and cost-effectively integrated into the Company's infrastructure.

XI. REGULATORY POLICY QUESTIONS

Q: How does KCP&L's EV CCN program fit into the regulatory framework of a regulated public utility in Missouri?

A: KCP&L's EV CCN project is a function of providing electric service under KCP&L's Certificate of Convenience and Necessity. KCP&L is able to integrate the charging stations into its distribution system grid. The CCN allows KCP&L to provide electric service to its mobile customers.

Furthermore, the CCN program is consistent with the 2016 Missouri Comprehensive State Energy Plan's directive of identifying "…opportunities associated with further development of energy resources and infrastructure for a sustainable and prosperous energy future."[3] In addition, the CCN "will also decrease risks in energy supply, delivery and security while, most importantly, promoting affordable prices."[4] The combination of locally sourced fuel, in the form of electricity, combined with my previous description of EVs being a lower cost alternative to fossil fuel transportation leads the CCN to fall in line with the Missouri Comprehensive State Energy Plan.

Q: Do utility-provided EV charging stations serve the public interest?

A: Yes. First, the benefits identified in the EPRI Study show that the program is in the public interest. Additionally, as noted in our Application, KCP&L's Clean Charge Network is in the public interest in Missouri because it places Missouri in the forefront of accommodating and promoting development of an industry that is expected to advance quickly in the near future, it proposes a plan that brings the network to Missouri in an efficient and effective manner, and it provides benefits to KCP&L's Missouri customers and

[3] https://energy.mo.gov/energy/docs/MCSEP.pdf, at p. 5.
[4] Id.

to Missouri citizens overall. Approval of KCP&L's Application and tariff allows KCP&L to evolve in its service offerings to meet the demands of mobile customers in its certificated territory, ensuring continued provisioning of sufficient and efficient electric service at just and reasonable rates. Finally, the CCN provides benefits to all KCP&L customers including increased off-peak electricity usage, environmental benefits from reduced CO_2 emissions and lower ozone-reducing pollutants, economic impacts resulting in job creation, improved customer programs, and lower costs and efficiency by having the utility install, own and operate the EV charging stations. The increase in home-based usage to charge EVs will also provide a broader base over which to spread system costs.

XII. TIME OF USE, REAL TIME PRICING AND STANDBY STUDIES

Q: In the last rate case, the Commission Ordered two specific studies to be conducted by the Company over the next two years. What is the status of those studies?

A: In Case No. ER-2014-0370,, the Commission Order KCP&L to perform a study on time of use and real time pricing rates (pages 90- 92)., The Commission ordered the Company to complete studies regarding both time of use pricing and real time pricing within two years of the effective date of this order. The Commission also ordered the Company to complete a study regarding standby rates within two years of the effective date of this order. The Company is working on these studies and willprovide the results of the studies in a timely manner.

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-2016-0285

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 thirty-two (32) 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 1st day of July, 2016.

Nicole A. Wehry
Notary Public

My commission expires: Feb. 4 2019

NICOLE A. WEHRY
Notary Public - Notary Seal
State of Missouri
Commissioned for Jackson County
My Commission Expires: February 04, 2019
Commission Number: 14391200

Requirements to Continue or Modify the Fuel Adjustment Clause

4 CSR 240-3.161 (3) When an electric utility files a general rate proceeding following the general rate proceeding that established its RAM as described by 4 CSR 240-20.090(2) in which it requests that its RAM be continued or modified, the electric utility shall file with the commission and serve parties, as provided in sections (9) through (11) in this rule 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-2.

(B) If the electric utility proposes to change the identification of the RAM on the customer's bill, an example customer bill showing how the proposed RAM shall be separately identified on affected customers' bills, including the proposed language, in accordance with 4 CSR 240-20.090(8):

No change is proposed.

(C) Proposed RAM rate schedules:

See Schedule TMR-3.

(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 the same as approved in Case No. ER-2014-0370. The change proposed in this filing is for the amounts contained in base rates as well as the addition of transmission of electricity by others expense and RTO assessments and fees offset by revenues from the transmission of electricity for others. Some key features of the FAC include:

- The FAC factor is based upon historical differences between the cost of fuel, energy, 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 95% 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 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. 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 amount for the current tariff is $.01186 per kWh.
- The proposed amount is $0.01987 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:

See Direct Testimony of Tim M. Rush.

(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 times 95%.

After defined 6 month accumulation periods (January-June and July-December) a filing in accordance with 4 CSR 240-20.090(4) is made with the Missouri Public Service Commission requesting a new Fuel Adjustment Rate ("FAR"). The collection periods for these FARs are 12 month periods (October-September and April-March).

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. Fuel used in the production of nuclear power generation is recorded 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, SPP Schedule 1-A fees are included in Accounts 561 and 575, and FERC Schedule 12 fees are in Account 928. Emission Allowance costs are in FERC account 509.

FERC Account Number 501

Subaccount 501000: coal commodity and transportation, side release and freeze conditioning agents, dust mitigation agents, accessorial charges as delineated in railroad accessorial tariffs [additional crew, closing hopper railcar doors, completion of loading of a unit train and its release for movement, completion of unloading of a unit train and its release for movement, delay for removal of frozen coal, destination detention, diversion of empty unit train (including administration fee, holding charges, and out-of-route charges which may include fuel surcharge), diversion of loaded coal trains, diversion of loaded unit train fees (including administration fee, additional mileage fee or out-of-route charges which may include fuel surcharge), fuel surcharge, held in transit, hold charge, locomotive release, miscellaneous handling of coal cars, origin detention, origin re-designation, out-of-route charges (including fuel surcharge), out-of-route movement, pick-up of locomotive power, placement and pick-up of loaded or empty private coal cars on railroad supplied tracks, placement and pick-up of loaded or empty private coal cars on shipper supplied tracks, railcar storage, release of locomotive power, removal, rotation and/or addition of cars, storage charges, switching, trainset positioning, trainset storage, and weighing], unit train maintenance, leases, taxes and depreciation, applicable taxes, natural gas costs, fuel quality adjustments, fuel hedging costs, fuel adjustments included in commodity and transportation costs, broker commissions and fees (fees charged by an agent, or agent's company to facilitate transactions between buyers and sellers) and margins (cash or collateral used to secure or maintain the Company's hedge position with a brokerage or exchange), oil commodity transportation, storage, taxes, fees, and fuel losses, inventory adjustments, and insurance recoveries, subrogation recoveries and settlement proceeds for increased fuel expenses in the 501 Accounts.

Subaccount 501020: the allocation of the allowed costs in the 501000, 501300, and 501400 accounts attributed to native load;

Subaccount 501030: the allocation of the allowed costs in the 501000, 501300, and 501400 accounts attributed to off system sales;

Subaccount 501300: fuel additives and consumable costs for Air Quality Control Systems ("AQCS") operations, such as ammonia, hydrated lime, lime, limestone,

powder activated carbon, sodium bicarbonate, trona, sulfur, and RESPond, or other consumables which perform similar functions;
Subaccount 501400, 501420: residual costs and revenues associated with combustion product, slag and ash disposal costs and revenues including contractors, materials and other miscellaneous expenses.
Subaccount 501500, 501502, 501503, 501504, 501505, 501506, 501507, 501508, and 501509: non-internal-labor costs associated with fuel handling.

FERC Account Number 518
Subaccount 518000: nuclear fuel commodity and hedging costs;
Subaccount 518201: nuclear fuel waste disposal expense;
Subaccount 518100: nuclear fuel oil.

FERC Account Number 547
Subaccount 547000: natural gas and oil costs for commodity, transportation, storage, taxes, fees and fuel losses, hedging costs for natural gas, oil, and natural gas used to cross-hedge power purchases or sales, and settlement proceeds, insurance recoveries, subrogation recoveries for increased fuel expenses, and broker commissions and fees (fees charged by an agent, or agent's company to facilitate transactions between buyers and sellers), and margins (cash or collateral used to secure or maintain the Company's hedge position with a brokerage or exchange).
Subaccount 547020: the allocation of the allowed costs in the 547000 and 547300 accounts attributed to native load;
Subaccount 547030: the allocation of the allowed costs in the 547000 and 547300 accounts attributed to off system sales;
Subaccount 547100, 547102: fuel handling costs other than internal labor [goods or services to purchase or acquire fuel or fuel transportation, including forecasts, market analyses or information, strategy development and contract or issue negotiation, to manage fuel purchases, including contract administration, to manage fuel inventories, to handle, pump or move fuel during or after receiving, including scheduling transportation, moving fuel in storage and transferring from one station to another]
Subaccount 547300: fuel additives and consumable costs for AQCS operations, such as ammonia or other consumables which perform similar functions

FERC Account Number 555
The following costs or revenues reflected in FERC Account Number 555:
Subaccount 555000: purchased power costs, energy charges from capacity purchases of any duration, insurance recoveries, and subrogation recoveries for purchased power expenses, hedging costs including broker commissions and fees (fees charged by an agent, or agent's company to facilitate transactions between buyers and sellers) and margins (cash or collateral used to secure or maintain the Company's hedge position with a brokerage or exchange), charges and credits related to the SPP Integrated Marketplace ("IM") or other IMs
including, energy, revenue neutrality, make whole and out of merit payments and distributions, over collected losses payments and distributions, Transmission

Congestion Rights ("TCR") and Auction Revenue Rights ("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 uplift charges or credits;
Subaccount 555005: capacity charges for capacity purchases one year or less in duration;
Subaccount 555030: the allocation of the allowed costs in the 555000 account attributed to purchases for off system sales

FERC Account Number 561
Subaccount 561400: all RTO scheduling, system control, dispatching services, and North American Electric Reliability Corporation ("NERC") fees;
Subaccount 561800: all RTO reliability, planning and standard development services costs

FERC Account Number 565
Subaccount 565000: all transmission costs used to serve native load and off-system sales;
Subaccount 565020: the allocation of the allowed costs in the 565000 account attributed to native load;
Subaccount 565027: the allocation of the allowed costs in the 565000 account attributed to transmission demand charges;
Subaccount 565030: the allocation of the allowed costs in account 565000 attributed to off system sales.

FERC Account Number 575
Subaccount 575700: all RTO market facilitation, monitoring and compliance services costs;

FERC Account Number 928
Subaccount 928000: all FERC assessment costs;

FERC Account Number 509
Subaccount 509000: NOx and SO_2 emission allowance costs including any associated hedging costs, and broker commissions and fees (fees charged by an agent, or agent's company to facilitate transactions between buyers and sellers) and margins (cash or collateral used to secure or maintain the Company's hedge position with a brokerage or exchange).

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:

The Federal Energy Regulatory Commission (FERC) Code of Federal Regulations is the basis for the Company's accounting codes. Sales for resale are recorded in FERC account 447. Revenues from the transmission of electricity for others are recorded in FERC account 456.1, and the revenues from the sale of emission allowances and renewable energy credits are recorded in FERC account 509 as an offset to expense. The following six digit Company accounts expand from the FERC accounts, and are included in the FAC.

<u>FERC Account Number 447</u>
Subaccount 447020: all revenues from off-system sales. This includes charges and credits related to the SPP IM including, energy, ancillary services, revenue sufficiency (such as make whole payments and out of merit payments and distributions), revenue neutrality payments and distributions, over collected losses payments and distributions, TCR and ARR settlements, demand reductions, virtual energy costs and 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 SPP uplift revenues or credits. Off-system sales revenues from full and partial requirements sales to municipalities that are served through bilateral contracts in excess of one year shall be excluded from OSSR component;
Subaccount 447012: capacity charges for capacity sales one year or less in duration;
Subaccount 447014: miscellaneous fixed costs
Subaccount 447030: the allocation of the includable sales in account 447002 not attributed to retail sales.

<u>FERC Account Number 456.1</u>
Subaccount 456100: all revenue from transmission of electricity for others.

<u>FERC Account Number 509</u>
Subaccount 509000: NOx and SO_2 emission allowance revenue amortizations as well as revenues from the sale of NOx and SO_2 emission allowances; revenues from the sale of Renewable Energy Credits that are not needed to meet the Renewable Energy Standards.

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:

In the Report and Order for Case No. ER-2014-0370 issued September 2, 2015, the Commission explains the reasoning for allowing only 95% of FAC eligible costs to be collected from customers,

"The Commission finds that allowing KCPL to have 100% recovery of its costs in an FAC would act as a disincentive for KCPL to control those costs. A 95%/5% sharing mechanism, where customers would be responsible for, or receive the benefit of, 95% of any deviation in fuel and purchased power costs would provide KCPL a sufficient opportunity to earn a fair return on equity while protecting KCPL's customers by providing the company an incentive to control costs. KCPL's FAC shall include an incentive clause providing that 95% deviation in fuel and purchased power costs from the base level shall be passed to customers and 5% shall be retained by KCPL."

(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.

The Company's books and records are audited annually by an independent public accounting firm.

The Company's internal audit staff performs periodic audits on the controls in place associated with the FAC.

(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 using commission approved allocation methods.

(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 Robert B. Hevert.

(O) A description of how responses to subsections (B) through (N) differ from responses to subsections (B) through (N) for the currently approved RAM:

The proposed tariffs have been changed as indicated in the body of my direct testimony to include transmission expenses and revenues and the associated fees and assessments. The definitions of the costs and revenues included in the FAC have been updated and expanded for more clarity. A new voltage level has been added to the recovery calculation. The losses in the J component were updated to current levels. Non-labor fuel handling was added to the recoverable costs. The base rate was updated. Sections (H) and (I) were expanded for more clarity. Section (J) was changed to the explanation from the Report and Order from Rate Case No. ER-2014-0370. In section (L) information was added relating to policies, procedures and practices that help to ensure prudency.

(P) 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.

(Q) The results of heat rate tests and/or efficiency tests on all the electric utility's nuclear and non-nuclear steam generators, HRSG, steam turbines and combustion turbines conducted within the previous twenty four (24) months:

See Direct Testimony of Burton L. Crawford.

(R) 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 alternatives and select a preferred resource plan that maintains adequate capacity reserves for reliability. KCP&L prepared and filed its latest triennial IRP report in April 2015. An update to that IRP report was filed March 15, 2016. Under the current IRP rule, the next IRP is to be filed March, 2017.

(S) 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.

(T) Any additional information that may have been ordered by the commission to be provided in the previous general rate proceeding:

No additional information was ordered by the commission to be provided in Rate Case No. ER-2014-0370.

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 _____ percent in the territory served as KCP&L Missouri.

For the average residential customer the proposed increase would be approximately $_____ per month.

The Company has also asked the PSC to continue the Fuel Adjustment Clause ("FAC"). The FAC allows the Company to adjust customers' bills two times per year based on the varying cost of fuel and power purchased in the current volatile market. Any increase or decrease in fuel costs is reflected in the FAC. This means the customer bill is based on more current fuel costs.

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 (please reference case number ___________); 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 – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided September 29, 2015 Through Effective Date of Rate Tariffs ER-2016-0285)

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 with formulas intact to support the filing.

Accumulation Periods	**Filing Dates**	**Recovery Periods**
January – June	By August 1	October – September
July – December	By February 1	April – March

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 ("SPP") charges, emission allowance costs and amortizations, cost of transmission of electricity by others associated with purchased power and off-system sales, 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 Missouri 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 multiplied by kWh billed.

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided September 29, 2015 Through Effective Date of Rate Tariffs ER-2016-0285)

FORMULAS AND DEFINITIONS OF COMPONENTS

FPA = 95% * ((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:
Subaccount 501000: coal commodity and transportation, side release and freeze conditioning agents, dust mitigation agents, accessorial charges as delineated in railroad accessorial tariffs [additional crew, closing hopper railcar doors, completion of loading of a unit train and its release for movement, completion of unloading of a unit train and its release for movement, delay for removal of frozen coal, destination detention, diversion of empty unit train (including administration fee, holding charges, and out-of-route charges which may include fuel surcharge), diversion of loaded coal trains, diversion of loaded unit train fees (including administration fee, additional mileage fee or out-of-route charges which may include fuel surcharge), fuel surcharge, held in transit, hold charge, locomotive release, miscellaneous handling of coal cars, origin detention, origin re-designation, out-of-route charges (including fuel surcharge), out-of-route movement, pick-up of locomotive power, placement and pick-up of loaded or empty private coal cars on railroad supplied tracks, placement and pick-up of loaded or empty private coal cars on shipper supplied tracks, railcar storage, release of locomotive power, removal, rotation and/or addition of cars, storage charges, switching, trainset positioning, trainset storage, and weighing], unit train maintenance and leases, applicable taxes, natural gas costs, fuel quality adjustments, fuel hedging costs, fuel adjustments included in commodity and transportation costs, broker commissions and fees (fees charged by an agent, or agent's company to facilitate transactions between buyers and sellers) and margins (cash or collateral used to secure or maintain the Company's hedge position with a brokerage or exchange), oil costs for commodity, transportation, storage, taxes, fees, and fuel losses, coal and oil inventory adjustments, and insurance recoveries, subrogation recoveries and settlement proceeds for increased fuel expenses in the 501 Accounts.
Subaccount 501020: the allocation of the allowed costs in the 501000, 501300, and 501400 accounts attributed to native load;
Subaccount 501030: the allocation of the allowed costs in the 501000, 501300, and 501400 accounts attributed to off system sales;
Subaccount 501300: fuel additives and consumable costs for Air Quality Control Systems ("AQCS") operations, such as ammonia, hydrated lime, lime, limestone, powder activated carbon, sulfur, and RESPond, or other consumables which perform similar functions;
Subaccount 501400: residual costs and revenues associated with combustion product, slag and ash disposal costs and revenues including contractors, materials and other miscellaneous expenses.

The following costs reflected in FERC Account Number 518:
Subaccount 518000: nuclear fuel commodity and hedging costs;
Subaccount 518201: nuclear fuel waste disposal expense;
Subaccount 518100: nuclear fuel oil.

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

The following costs reflected in FERC Account Number 547:
Subaccount 547000: natural gas, and oil costs for commodity, transportation, storage, taxes, fees and fuel losses, hedging costs for natural gas, oil, and natural gas used to cross-hedge purchased power or sales, and settlement proceeds, insurance recoveries, subrogation recoveries for increased fuel expenses, and broker commissions and fees (fees charged by an agent, or agent's company to facilitate transactions between buyers and sellers), and margins (cash or collateral used to secure or maintain the Company's hedge position with a brokerage or exchange).
Subaccount 547020: the allocation of the allowed costs in the 547000 and 547300 accounts attributed to native load;
Subaccount 547030: the allocation of the allowed costs in the 547000 and 547300 accounts attributed to off system sales;
Subaccount 547300: fuel additives.

E = Net Emission Costs:
The following costs and revenues reflected in FERC Account Number 509:
Subaccount 509000: NOx and SO_2 emission allowance costs and revenue amortizations offset by revenues from the sale of NOx and SO_2 emission allowances including any associated hedging costs, and broker commissions and fees (fees charged by an agent, or agent's company to facilitate transactions between buyers and sellers) and margins (cash or collateral used to secure or maintain the Company's hedge position with a brokerage or exchange).

PP = Purchased Power Costs:
The following costs or revenues reflected in FERC Account Number 555:
Subaccount 555005: capacity charges for capacity purchases one year or less in duration;
Subaccount 555000: purchased power costs, energy charges from capacity purchases of any duration, insurance recoveries, and subrogation recoveries for purchased power expenses, hedging costs including broker commissions and fees (fees charged by an agent, or agent's company to facilitate transactions between buyers and sellers) and margins (cash or collateral used to secure or maintain the Company's hedge position with a brokerage or exchange), charges and credits related to the SPP Integrated Marketplace ("IM") including, energy, revenue neutrality, make whole and out of merit payments and distributions, over collected losses payments and distributions, Transmission Congestion Rights ("TCR") and Auction Revenue Rights ("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 uplift charges or credits;
Subaccount 555021: the allocation of the allowed costs in the 555000 account attributed to intercompany purchases for native load;
Subaccount 555030: the allocation of the allowed costs in the 555000 account attributed to purchases for off system sales;
Subaccount 555031: the allocation of the allowed costs in the 555000 account attributed to intercompany purchases for off system sales.

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided September 29, 2015 Through Effective Date of Rate Tariffs ER-2016-0285)

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

TC = Transmission Costs:
The following costs reflected in FERC Account Number 565:
Subaccount 565000: non-SPP transmission used to serve off system sales or to make purchases for load and 7.3% of the SPP transmission service costs which includes the schedules listed below as well as any adjustments to the charges in the schedules below:

- Schedule 7 – Long Term Firm and Short Term Point to Point Transmission Service
- Schedule 8 – Non Firm Point to Point Transmission Service
- Schedule 9 – Network Integration Transmission Service
- Schedule 10 – Wholesale Distribution Service
- Schedule 11 – Base Plan Zonal Charge and Region Wide Charge

Subaccount 565020: the allocation of the allowed costs in the 565000 account attributed to native load;
Subaccount 565027: the allocation of the allowed costs in the 565000 account attributed to transmission demand charges;
Subaccount 565030: the allocation of the allowed costs in account 565000 attributed to off system sales.

OSSR = Revenues from Off-System Sales:
The following revenues or costs reflected in FERC Account Number 447:
Subaccount 447002: all revenues from off-system sales. This includes charges and credits related to the SPP IM including, energy, ancillary services, revenue sufficiency (such as make whole payments and out of merit payments and distributions), revenue neutrality payments and distributions, over collected losses payments and distributions, TCR and ARR settlements, demand reductions, virtual energy costs and 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 SPP uplift revenues or credits. Off-system sales revenues from full and partial requirements sales to municipalities that are served through bilateral contracts in excess of one year shall be excluded from OSSR component;
Subaccount 447012: capacity charges for capacity sales one year or less in duration;
Subaccount 447030: the allocation of the includable sales in account 447002 not attributed to retail sales.

R = Renewable Energy Credit Revenue:
Revenues reflected in FERC account 509000 from the sale of Renewable Energy Credits that are not needed to meet the Renewable Energy Standard.

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 component J below. Any cost identified above which is a Kansas-only cost shall be excluded from the ANEC calculation.

FUEL ADJUSTMENT CLAUSE – Rider FAC
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FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

Hedging costs are defined as realized losses and costs (including broker 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, TCRs, virtual energy transactions, or similar instruments.

Costs and revenues not specifically detailed in Factors FC, PP, E, TC, OSSR, or R shall not be included in the Company's FAR filings; provided however, in the case of Factors PP, TC or OSSR, the market settlement charge types under which SPP or another centrally administered market (e.g., PJM or MISO) bills/credits a cost or revenue need not be detailed in Factors PP or OSSR for the costs or revenues to be considered specifically detailed in Factors PP or OSSR; and provided further, should the SPP or another centrally administered market (e.g. PJM or MISO) implement a new market settlement charge type not listed below or a new schedule not listed in TC:

A. The Company may include the new schedule, charge type cost or revenue in its FAR filings if the Company believes the new schedule, charge type cost or revenue possesses the characteristics of, and is of the nature of, the costs or revenues listed below or in the schedules listed in TC, as the case may be, subject to the requirement that the Company make a filing with the Commission as outlined in B below and also subject to another party's right to challenge the inclusion as outlined in E. below;

B. The Company will make a filing with the Commission giving the Commission notice of the new schedule or charge type no later than 60 days prior to the Company including the new schedule, charge type cost or revenue in a FAR filing. Such filing shall identify the proposed accounts affected by such change, provide a description of the new charge type demonstrating that it possesses the characteristics of, and is of the nature of, the costs or revenues listed in factors PP, TC or OSSR as the case may be, and identify the preexisting schedule, or market settlement charge type(s) which the new schedule or charge type replaces or supplements;

C. The Company will also provide notice in its monthly reports required by the Commission's fuel adjustment clause rules that identifies the new schedule, charge type costs or revenues by amount, description and location within the monthly reports;

D. The Company shall account for the new schedule, charge type costs or revenues in a manner which allows for the transparent determination of current period and cumulative costs or revenues;

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FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

A. If the Company makes the filing provided for in B above and a party challenges the inclusion, such challenge will not delay approval of the FAR filing. To challenge the inclusion of a new schedule or charge type, a party shall make a filing with the Commission based upon that party's contention that the new schedule, charge type costs or revenues at issue should not have been included, because they do not possess the characteristics of the schedules, costs or revenues listed in Factors PP, TC or OSSR, as the case may be. A party wishing to challenge the inclusion of a schedule or charge type shall include in its filing the reasons why it believes the Company did not show that the new schedule or charge type possesses the characteristics of the costs or revenues listed in Factors TC, PP or OSSR, as the case may be, and its filing shall be made within 30 days of the Company's filing under B above. In the event of a timely challenge, the Company shall bear the burden of proof to support its decision to include a new schedule or charge type in a FAR filing. Should such challenge be upheld by the Commission, any such costs will be refunded (or revenues retained) through a future FAR filing in a manner consistent with that utilized for Factor P; and

F. A party other than the Company may seek the inclusion of a new schedule or charge type in a FAR filing by making a filing with the Commission no less than 60 days before the Company's next FAR filing date of August 1 or February 1. Such a filing shall give the Commission notice that such party believes the new schedule or charge type should be included because it possesses the characteristics of, and is of the nature of, the costs or revenues listed in factors PP, TC or OSSR, as the case may be. The party's filing shall identify the proposed accounts affected by such change, provide a description of the new schedule or charge type demonstrating that it possesses the characteristics of, and is of the nature of, the schedules, costs or revenues listed in factors PP, TC or OSSR as the case may be, and identify the preexisting schedule or market settlement charge type(s) which the new schedule or charge type replaces or supplements. If a party makes the filing provided for by this paragraph F and a party (including the Company) challenges the inclusion, such challenge will not delay inclusion of the new schedule or charge type in the FAR filing or delay approval of the FAR filing. To challenge the inclusion of a new schedule or charge type, the challenging party shall make a filing with the Commission based upon that party's contention that the new schedule or charge type costs or revenues at issue should not have been included, because they do not possess the characteristics of the schedules, costs or revenues listed in Factors PP, TC, or OSSR, as the case may be. The challenging party shall make its filing challenging the inclusion and stating the reasons why it believes the new schedule or charge type does not possess the characteristic of the costs or revenues listed in Factors PP, TC or OSSR, as the case may be, within 30 days of the filing that seeks inclusion of the new schedule or charge type. In the event of a timely challenge, the party seeking the inclusion of the new schedule or charge type shall bear the burden of proof to support its contention that the new schedule or charge type should be included in the Company's FAR filings. Should such challenge be upheld by the Commission, any such costs will be refunded (or revenues retained) through a future FAR filing in a manner consistent with that utilized for Factor P.

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
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FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

SPP IM charge/revenue types that are included in the FAC are listed below:

Day Ahead Regulation Down Service Amount
Day Ahead Regulation Down Service Distribution Amount
Day Ahead Regulation Up Service Amount
Day Ahead Regulation Up Service Distribution Amount
Day Ahead Spinning Reserve Amount
Day Ahead Spinning Reserve Distribution Amount
Day Ahead Supplemental Reserve Amount
Day Ahead Supplemental Reserve Distribution Amount
Real Time Contingency Reserve Deployment Failure Amount
Real Time Contingency Reserve Deployment Failure Distribution Amount
Real Time Regulation Service Deployment Adjustment Amount
Real Time Regulation Down Service Amount
Real Time Regulation Down Service Distribution Amount
Real Time Regulation Non-Performance
Real Time Regulation Non-Performance Distribution
Real Time Regulation Up Service Amount
Real Time Regulation Up Service Distribution Amount
Real Time Spinning Reserve Amount
Real Time Spinning Reserve Distribution Amount
Real Time Supplemental Reserve Amount
Real Time Supplemental Reserve Distribution Amount
Day Ahead Asset Energy
Day Ahead Non-Asset Energy
Day Ahead Virtual Energy Amount
Real Time Asset Energy Amount
Real Time Non-Asset Energy Amount
Real Time Virtual Energy Amount
Transmission Congestion Rights Funding Amount
Transmission Congestion Rights Daily Uplift Amount
Transmission Congestion rights Monthly Payback Amount
Transmission Congestion Rights Annual Payback Amount
Transmission Congestion Rights Annual Closeout Amount
Transmission Congestion Rights Auction Transaction Amount
Auction Revenue Rights Funding Amount
Auction Revenue Rights Uplift Amount
Auction Revenue Rights Monthly Payback Amount
Auction Revenue Annual Payback Amount
Auction Revenue Rights Annual Closeout Amount
Day Ahead Virtual Energy Transaction Fee Amount
Day Ahead Demand Reduction Amount
Day Ahead Grandfathered Agreement Carve Out Daily Amount
Grandfathered Agreement Carve Out Distribution Daily Amount

FUEL ADJUSTMENT CLAUSE – Rider FAC
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FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

SPP IM charge/revenue types that are included in the FAC (continued)

- Day Ahead Grandfathered Agreement Carve Out Monthly Amount
- Grandfathered Agreement Carve Out Distribution Monthly Amount
- Day Ahead Grandfathered Agreement Carve Out Yearly Amount
- Grandfathered Agreement Carve Out Distribution Yearly Amount
- Day Ahead Make Whole Payment Amount
- Day Ahead Make Whole Payment Distribution Amount
- Day Ahead Over Collected Losses Distribution Amount
- Miscellaneous Amount
- Reliability Unit Commitment Make Whole Payment Amount
- Real Time Out of Merit Amount
- Reliability Unit Commitment Make Whole Payment Distribution Amount
- Over Collected Losses Distribution Amount
- Real Time Joint Operating Agreement Amount
- Real Time Reserve Sharing Group Amount
- Real Time Reserve Sharing Group Distribution Amount
- Real Time Demand Reduction Amount
- Real Time Demand Reduction Distribution Amount
- Real Time Pseudo Tie Congestion Amount
- Real Time Pseudo Tie Losses Amount
- Unused Regulation Up Mileage Make Whole Payment Amount
- Unused Regulation Down Mileage Make Whole Payment Amount
- Revenue Neutrality Uplift Distribution Amount

Should FERC require any item covered by components FC, E, PP, TC, OSSR or R to be recorded in an account different than the FERC accounts listed in such components, such items shall nevertheless be included in component 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 the Rider FAC 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. N e t 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

BF = Company base factor costs per kWh: $0.01186

FUEL ADJUSTMENT CLAUSE – Rider FAC
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FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

J = Missouri Retail Energy Ratio = (MO Retail kWh sales + MO Losses) / (MO Retail kWh Sales + MO Losses + KS Retail kWh Sales + KS Losses + Sales for Resale, Municipals kWh Sales [includes border customers] + Sales for Resale, Municipals Losses)

MO Losses = 6.121%; KS Losses = 6.298%; Sales for Resale, Municipals Losses = 21.50%

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.

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

FUEL ADJUSTMENT CLAUSE – Rider FAC
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TRUE-UPS

After completion of each RP, the Company shall make a true-up filing by the filing date of its next FAR filing. Any true-up adjustments shall be reflected in component "T" above. Interest on the true-up adjustment will be included in component "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 component "P" above unless a separate refund is ordered by the Commission. Interest on the prudence adjustment will be included in component "I" above.

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided Effective Date of Rate Tariffs for ER-2016-0285 and Thereafter)

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 May 31, 2021, 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 with formulas intact to support the filing.

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

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 ("SPP") charges, emission allowance costs and amortizations, cost of transmission of electricity by others as well as associated Regional Transmission Organization ("RTO") fees, Federal Energy Regulatory Commission ("FERC") assessments, 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") as well as other revenues received for transmission of electricity for others. 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 Missouri 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 multiplied by kWh billed.

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided Effective Date of Rate Tariffs for ER-2016-0285 and Thereafter)

FORMULAS AND DEFINITIONS OF COMPONENTS

FPA = 95% * ((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 FERC Account Number 501:
Subaccount 501000: coal commodity and transportation, side release and freeze conditioning agents, dust mitigation agents, accessorial charges as delineated in railroad accessorial tariffs [additional crew, closing hopper railcar doors, completion of loading of a unit train and its release for movement, completion of unloading of a unit train and its release for movement, delay for removal of frozen coal, destination detention, diversion of empty unit train (including administration fee, holding charges, and out-of-route charges which may include fuel surcharge), diversion of loaded coal trains, diversion of loaded unit train fees (including administration fee, additional mileage fee or out-of-route charges which may include fuel surcharge), fuel surcharge, held in transit, hold charge, locomotive release, miscellaneous handling of coal cars, origin detention, origin re-designation, out-of-route charges (including fuel surcharge), out-of-route movement, pick-up of locomotive power, placement and pick-up of loaded or empty private coal cars on railroad supplied tracks, placement and pick-up of loaded or empty private coal cars on shipper supplied tracks, railcar storage, release of locomotive power, removal, rotation and/or addition of cars, storage charges, switching, trainset positioning, trainset storage, and weighing], unit train maintenance, leases, taxes and depreciation, applicable taxes, natural gas costs, fuel quality adjustments, fuel hedging costs, fuel adjustments included in commodity and transportation costs, broker commissions and fees (fees charged by an agent, or agent's company to facilitate transactions between buyers and sellers) and margins (cash or collateral used to secure or maintain the Company's hedge position with a brokerage or exchange), oil commodity transportation, storage, taxes, fees, and fuel losses, inventory adjustments, and insurance recoveries, subrogation recoveries and settlement proceeds for increased fuel expenses in the 501 Accounts.
Subaccount 501020: the allocation of the allowed costs in the 501000, 501300, and 501400 accounts attributed to native load;
Subaccount 501030: the allocation of the allowed costs in the 501000, 501300, and 501400 accounts attributed to off system sales;
Subaccount 501300: fuel additives and consumable costs for Air Quality Control Systems ("AQCS") operations, such as ammonia, hydrated lime, lime, limestone, powder activated carbon, sodium bicarbonate, trona, sulfur, and RESPond, or other consumables which perform similar functions;
Subaccount 501400, 501420: residual costs and revenues associated with combustion product, slag and ash disposal costs and revenues including contractors, materials and other miscellaneous expenses.

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Subaccount 501500 - 501509: fuel handling costs other than internal labor [goods or services to purchase or acquire fuel or fuel transportation, including forecasts, market analyses or information, strategy development and contract or issue negotiation, to manage fuel purchases, including contract administration, monitoring and analyzing fuel quality, to manage fuel inventories, including measuring and establishing volume levels, to handle or move fuel from shipping facility to first bunker, hopper, bucket, tank, or holder of boiler house structure, including scheduling transportation, moving fuel in storage and transferring from one station to another].

The following costs reflected in FERC Account Number 518:
Subaccount 518000: nuclear fuel commodity and hedging costs;
Subaccount 518201: nuclear fuel waste disposal expense;
Subaccount 518100: nuclear fuel oil.

The following costs reflected in FERC Account Number 547:
Subaccount 547000: natural gas and oil costs for commodity, transportation, storage, taxes, fees and fuel losses, hedging costs for natural gas, oil, and natural gas used to cross-hedge power purchases or sales, and settlement proceeds, insurance recoveries, subrogation recoveries for increased fuel expenses, and broker commissions and fees (fees charged by an agent, or agent's company to facilitate transactions between buyers and sellers), and margins (cash or collateral used to secure or maintain the Company's hedge position with a brokerage or exchange).
Subaccount 547020: the allocation of the allowed costs in the 547000 and 547300 accounts attributed to native load;
Subaccount 547030: the allocation of the allowed costs in the 547000 and 547300 accounts attributed to off system sales;
Subaccount 547100, 547102: fuel handling costs other than internal labor [goods or services to purchase or acquire fuel or fuel transportation, including forecasts, market analyses or information, strategy development and contract or issue negotiation, to manage fuel purchases, including contract administration, to manage fuel inventories, to handle, pump or move fuel during or after receiving, including scheduling transportation, moving fuel in storage and transferring from one station to another]
Subaccount 547300: fuel additives and consumable costs for AQCS operations, such as ammonia or other consumables which perform similar functions;

E = Net Emission Costs:
The following costs and revenues reflected in FERC Account Number 509:
Subaccount 509000: NOx and SO_2 emission allowance costs and revenue amortizations as well as revenues from the sale of NOx and SO_2 emission allowances including any associated hedging costs, and broker commissions and fees (fees charged by an agent, or agent's company to facilitate transactions between buyers and sellers) and margins (cash or collateral used to secure or maintain the Company's hedge position with a brokerage or exchange).

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PP = Purchased Power Costs:
The following costs or revenues reflected in FERC Account Number 555:
Subaccount 555000: purchased power costs, energy charges from capacity purchases of any duration, insurance recoveries, and subrogation recoveries for purchased power expenses, hedging costs including broker commissions and fees (fees charged by an agent, or agent's company to facilitate transactions between buyers and sellers) and margins (cash or collateral used to secure or maintain the Company's hedge position with a brokerage or exchange), charges and credits related to the SPP Integrated Marketplace ("IM") or other IMs
including, energy, revenue neutrality, make whole and out of merit payments and distributions, over collected losses payments and distributions, Transmission Congestion Rights ("TCR") and Auction Revenue Rights ("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 uplift charges or credits;
Subaccount 555005: capacity charges for capacity purchases one year or less in duration;
Subaccount 555030: the allocation of the allowed costs in the 555000 account attributed to purchases for off system sales;

TC = Transmission Costs:
The following costs reflected in FERC Account Number 561:
Subaccount 561400: all RTO scheduling, system control, dispatching services, and North American Electric Reliability Corporation ("NERC") fees;
Subaccount 561800: all RTO reliability, planning and standard development services costs;
The following costs reflected in FERC Account Number 565:
Subaccount 565000: all transmission costs used to serve native load and off-system sales;
Subaccount 565020: the allocation of the allowed costs in the 565000 account attributed to native load;
Subaccount 565027: the allocation of the allowed costs in the 565000 account attributed to transmission demand charges;
Subaccount 565030: the allocation of the allowed costs in account 565000 attributed to off system sales.
The following costs reflected in FERC Account Number 575:
Subaccount 575700: all RTO market facilitation, monitoring and compliance services costs;
The following costs reflected in FERC Account Number 928000:
Subaccount 928000: all FERC assessment costs;
The following revenues reflected in FERC Account Number 456:
Subaccount 456100: all revenue from transmission of electricity for others.

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

OSSR = Revenues from Off-System Sales:
The following revenues or costs reflected in FERC Account Number 447:
Subaccount 447020: all revenues from off-system sales. This includes charges and credits related to the SPP IM including, energy, ancillary services, revenue sufficiency (such as make whole payments and out of merit payments and distributions), revenue neutrality payments and distributions, over collected losses payments and distributions, TCR and ARR settlements, demand reductions, virtual energy costs and 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 SPP uplift revenues or credits. Off-system sales revenues from full and partial requirements sales to municipalities that are served through bilateral contracts in excess of one year shall be excluded from OSSR component;
Subaccount 447012: capacity charges for capacity sales one year or less in duration;
Subaccount 447014: miscellaneous fixed costs
Subaccount 447030: the allocation of the includable sales in account 447002 not attributed to retail sales.

R = Renewable Energy Credit Revenue:
Revenues reflected in FERC account 509000 from the sale of Renewable Energy Credits that are not needed to meet the Renewable Energy Standards.

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 component 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 broker 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, TCRs, virtual energy transactions, or similar instruments.

Costs and revenues not specifically detailed in Factors FC, PP, E, TC, OSSR, or R shall not be included in the Company's FAR filings; provided however, in the case of Factors PP, TC or OSSR, the market settlement charge types under which SPP or another centrally administered market (e.g., PJM or MISO) bills/credits a cost or revenue need not be detailed in Factors PP, TC or OSSR for the costs or revenues to be considered specifically detailed in Factors PP, TC or OSSR; and provided further, should the SPP or another centrally administered market (e.g. PJM or MISO) implement a new market settlement charge type not listed below or a new schedule not listed in TC:

A. The Company may include the new schedule, charge type cost or revenue in its FAR filings if the Company believes the new schedule, charge type cost or revenue possesses the characteristics of, and is of the nature of, the costs or revenues listed below or in the schedules listed in TC, as the case may be, subject to the requirement that the Company make a filing with the Commission as outlined in B below and also subject to another party’s right to challenge the inclusion as outlined in E. below;

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B. The Company will make a filing with the Commission giving the Commission notice of the new schedule or charge type no later than 60 days prior to the Company including the new schedule, charge type cost or revenue in a FAR filing. Such filing shall identify the proposed accounts affected by such change, provide a description of the new charge type demonstrating that it possesses the characteristics of, and is of the nature of, the costs or revenues listed in factors PP, TC or OSSR as the case may be, and identify the preexisting schedule, or market settlement charge type(s) which the new schedule or charge type replaces or supplements;

C. The Company will also provide notice in its monthly reports required by the Commission's fuel adjustment clause rules that identifies the new schedule, charge type costs or revenues by amount, description and location within the monthly reports;

D. The Company shall account for the new schedule, charge type costs or revenues in a manner which allows for the transparent determination of current period and cumulative costs or revenues;

E. If the Company makes the filing provided for in B above and a party challenges the inclusion, such challenge will not delay approval of the FAR filing. To challenge the inclusion of a new schedule or charge type, a party shall make a filing with the Commission based upon that party's contention that the new schedule, charge type costs or revenues at issue should not have been included, because they do not possess the characteristics of the schedules, costs or revenues listed in Factors PP, TC or OSSR, as the case may be. A party wishing to challenge the inclusion of a schedule or charge type shall include in its filing the reasons why it believes the Company did not show that the new schedule or charge type possesses the characteristics of the costs or revenues listed in Factors TC, PP or OSSR, as the case may be, and its filing shall be made within 30 days of the Company's filing under B above. In the event of a timely challenge, the Company shall bear the burden of proof to support its decision to include a new schedule or charge type in a FAR filing. Should such challenge be upheld by the Commission, any such costs will be refunded (or revenues retained) through a future FAR filing in a manner consistent with that utilized for Factor P; and

F. A party other than the Company may seek the inclusion of a new schedule or charge type in a FAR filing by making a filing with the Commission no less than 60 days before the Company's next FAR filing date of August 1 or February 1. Such a filing shall give the Commission notice that such party believes the new schedule or charge type should be included because it possesses the characteristics of, and is of the nature of, the costs or revenues listed in factors PP, TC or OSSR, as the case may be. The party's filing shall identify the proposed accounts affected by such change, provide a description of the new schedule or charge type demonstrating that it possesses the characteristics of, and is of the nature of, the schedules, costs or revenues listed in factors PP, TC or OSSR as the case may be, and identify the preexisting schedule or market settlement charge type(s) which the new schedule or charge type replaces or supplements. If a party makes the filing provided for by this paragraph F and a party (including the Company) challenges the inclusion, such challenge will not delay inclusion of the new schedule or charge type in the FAR filing or delay approval of the FAR filing. To challenge the inclusion of a new schedule or charge type, the challenging party shall make a filing with the Commission based upon that party's contention that the new schedule or charge type costs or revenues at issue should not

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have been included, because they do not possess the characteristics of the schedules, costs or revenues listed in Factors PP, TC, or OSSR, as the case may be. The challenging party shall make its filing challenging the inclusion and stating the reasons why it believes the new schedule or charge type does not possess the characteristic of the costs or revenues listed in Factors PP, TC or OSSR, as the case may be, within 30 days of the filing that seeks inclusion of the new schedule or charge type. In the event of a timely challenge, the party seeking the inclusion of the new schedule or charge type shall bear the burden of proof to support its contention that the new schedule or charge type should be included in the Company's FAR filings. Should such challenge be upheld by the Commission, any such costs will be refunded (or revenues retained) through a future FAR filing in a manner consistent with that utilized for Factor P.

SPP IM charge/revenue types that are included in the FAC are listed below:

Day Ahead Regulation Down Service Amount
Day Ahead Regulation Down Service Distribution Amount
Day Ahead Regulation Up Service Amount
Day Ahead Regulation Up Service Distribution Amount
Day Ahead Spinning Reserve Amount
Day Ahead Spinning Reserve Distribution Amount
Day Ahead Supplemental Reserve Amount
Day Ahead Supplemental Reserve Distribution Amount
Real Time Contingency Reserve Deployment Failure Amount
Real Time Contingency Reserve Deployment Failure Distribution Amount
Real Time Regulation Service Deployment Adjustment Amount
Real Time Regulation Down Service Amount
Real Time Regulation Down Service Distribution Amount
Real Time Regulation Non-Performance
Real Time Regulation Non-Performance Distribution
Real Time Regulation Up Service Amount
Real Time Regulation Up Service Distribution Amount
Real Time Spinning Reserve Amount
Real Time Spinning Reserve Distribution Amount
Real Time Supplemental Reserve Amount
Real Time Supplemental Reserve Distribution Amount
Day Ahead Asset Energy
Day Ahead Non-Asset Energy
Day Ahead Virtual Energy Amount
Real Time Asset Energy Amount
Real Time Non-Asset Energy Amount
Real Time Virtual Energy Amount
Transmission Congestion Rights Funding Amount
Transmission Congestion Rights Daily Uplift Amount
Transmission Congestion rights Monthly Payback Amount
Transmission Congestion Rights Annual Payback Amount
Transmission Congestion Rights Annual Closeout Amount
Transmission Congestion Rights Auction Transaction Amount

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

SPP IM charge/revenue types that are included in the FAC (continued)

- Auction Revenue Rights Funding Amount
- Auction Revenue Rights Uplift Amount
- Auction Revenue Rights Monthly Payback Amount
- Auction Revenue Annual Payback Amount
- Auction Revenue Rights Annual Closeout Amount
- Day Ahead Virtual Energy Transaction Fee Amount
- Day Ahead Demand Reduction Amount
- Day Ahead Demand Reduction Distribution Amount
- Day Ahead Grandfathered Agreement Carve Out Daily Amount
- Grandfathered Agreement Carve Out Distribution Daily Amount
- Day Ahead Grandfathered Agreement Carve Out Monthly Amount
- Grandfathered Agreement Carve Out Distribution Monthly Amount
- Day Ahead Grandfathered Agreement Carve Out Yearly Amount
- Grandfathered Agreement Carve Out Distribution Yearly Amount
- Day Ahead Make Whole Payment Amount
- Day Ahead Make Whole Payment Distribution Amount
- Miscellaneous Amount
- Reliability Unit Commitment Make Whole Payment Amount
- Real Time Out of Merit Amount
- Reliability Unit Commitment Make Whole Payment Distribution Amount
- Over Collected Losses Distribution Amount
- Real Time Joint Operating Agreement Amount
- Real Time Reserve Sharing Group Amount
- Real Time Reserve Sharing Group Distribution Amount
- Real Time Demand Reduction Amount
- Real Time Demand Reduction Distribution Amount
- Real Time Pseudo Tie Congestion Amount
- Real Time Pseudo Tie Losses Amount
- Unused Regulation Up Mileage Make Whole Payment Amount
- Unused Regulation Down Mileage Make Whole Payment Amount
- Revenue Neutrality Uplift Distribution Amount

Should FERC require any item covered by components FC, E, PP, TC, OSSR or R to be recorded in an account different than the FERC accounts listed in such components, such items shall nevertheless be included in component 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 the Rider FAC 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. N e t Base Energy costs will be calculated as shown below:

S_{AP} x Base Factor (“BF”)

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

BF = Company base factor costs per kWh: $0.01987

J = Missouri Retail Energy Ratio = (MO Retail kWh sales + MO Losses) / (MO Retail kWh Sales + MO Losses + KS Retail kWh Sales + KS Losses + Sales for Resale, Municipals kWh Sales [includes border customers] + Sales for Resale, Municipals Losses)
MO Losses = 6.32%; KS Losses = 7.52%; Sales for Resale, Municipals Losses = 6.84%

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.

FAR = FPA/S_{RP}

Single Accumulation Period Transmission/Substation Voltage $FAR_{Trans/Sub}$ = FAR * $VAF_{Trans/Sub}$
Single Accumulation Period Primary Voltage FAR_{Prim} = FAR * VAF_{Prim}
Single Accumulation Period Secondary Voltage FAR_{Sec} = FAR * VAF_{Sec}

Annual Primary Voltage $FAR_{Trans/Sub}$ = Aggregation of the two Single Accumulation Period Transmission/Substation 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
Annual Secondary Voltage FAR_{Sec} = Aggregation of the two Single Accumulation Period Secondary 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
$VAF_{Trans/Sub}$ = Expansion factor for transmission/substation and higher voltage level customers
VAF_{Prim} = Expansion factor for between primary and trans/sub voltage level customers
VAF_{Sec} = Expansion factor for lower than primary voltage customers

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TRUE-UPS

After completion of each RP, the Company shall make a true-up filing by the filing date of its next FAR filing. Any true-up adjustments shall be reflected in component "T" above. Interest on the true-up adjustment will be included in component "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 component "P" above unless a separate refund is ordered by the Commission. Interest on the prudence adjustment will be included in component "I" above.

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Accumulation Period Ending:			
			KCPL-MO
1	Actual Net Energy Cost (ANEC) = (FC+E+PP+TC-OSSR-R)		$0
2	Net Base Energy Cost (B)	-	$311,624,361
	2.1 Base Factor (BF)		$0.01987
	2.2 Accumulation Period NSI (S_{AP})		15,684,797,000
3	(ANEC-B)		$0
4	Jurisdictional Factor (J)	*	0%
5	(ANEC-B)*J		$0
6	Customer Responsibility	*	95%
7	95% *((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 $FAR_{Trans/Sub}$ = FAR x $VAF_{Trans/Sub}$		$0.00000
15	Prior Period $FAR_{Trans/Sub}$	+	$0.00000
16	Current Annual $FAR_{Trans/Sub}$		$0.00000
17	Current Period FAR_{Prim} = FAR x VAF_{Prim}		$0.00000
18	Prior Period FAR_{Prim}	+	$0.00000
19	Current Annual FAR_{Prim}		$0.00000
20	Current Period FAR_{Sec} = FAR x VAF_{Sec}		$0.00000
21	Prior Period FAR_{Sec}		$0.00000
22	Current Annual FAR_{Sec}	+	$0.00000
23	$VAF_{Trans/Sub}$ = 1.0195		
24	VAF_{Prim} = 1.0452		
25	VAF_{Sec} = 1.0707		

SCHEDULE TMR-4

THIS DOCUMENT CONTAINS HIGHLY CONFIDENTIAL INFORMATION NOT AVAILABLE TO THE PUBLIC

PUBLIC ELECTRIC VEHICLE CHARGING STATION SERVICE
Schedule CCN

PURPOSE:

The Company owns electric vehicle (EV) charging stations throughout its Missouri service territory that are available to the public for purpose of charging an EV and may be used by any EV owner who resides either within or outside the Company's Missouri service territory.

AVAILABILITY:

This rate schedule applies to all energy provided to charge EVs at the Company's public EV charging stations. EV charging service will be available at the Company-owned EV charging stations installed at Company and Host locations. The EV charging stations are accessed by using a card provided to users with an established account from the Company's third party vendor.

HOST PARTICIPATION:

EV charging stations are located at Company and Host sites. A Host is an entity within the Company's Missouri service territory that applies for and agrees to locate one or more Company EV charging stations upon their premise(s). Host applications will be evaluated for acceptance based on each individual site and application. If a Host's application is approved, the Host must execute an agreement with the Company covering the terms and provisions applicable to the EV charging station(s) upon their premise(s). No Host shall receive any compensation for locating an EV charging station upon their premise(s).

The maximum number of EV charging stations identified by the Company for its Missouri service territory under this Schedule CCN is 350. The Company may not exceed 350 EV charging stations under this tariff without approval of the Commission.

PROGRAM ADMINISTRATION:

Charges under this Schedule CCN will be administered and billed through either the Company's third party vendor on behalf of the Company, or directly by the Company depending on the Billing Option chosen by the Host.

BILLING OPTIONS:

The charges applicable to an EV charging station session shall include an Energy Charge for each kilowatt-hour (kWh) provided to charge an EV, plus any applicable riders, surcharges, taxes and fees, and an optional Session Charge dependent on the Billing Option chosen by the Host.

PUBLIC ELECTRIC VEHICLE CHARGING STATION SERVICE
Schedule CCN (Continued)

A Host may choose between one of two Billing Options for all EV charging stations located upon their premises. The Host's agreement with the Company will identify the chosen Billing Option applicable to the EV charging stations located on its premise. The EV charging station screen and third party vendor's customer web portal will identify the applicable Energy and Session Charges that will be the responsibility of the user at each EV charging station location.

Option 1: The Host pays the kilowatt-hour (kWh) Energy Charge plus any applicable riders, surcharges, taxes and fees, and, if applicable, the EV charging station user pays the Session Charge.

Option 2: The EV charging station user pays the kilowatt-hour (kWh) Energy Charge plus any applicable riders, surcharges, taxes and fees, and, if applicable, the Session Charge.

RATES FOR SERVICE:

The EV charging station screen and third party vendor's customer web portal will identify both the: (1) per kWh rate as equal to the Energy Charge (below) plus all applicable riders, surcharges, taxes and fees; and (2) any Session Charge rate(s) applicable to that charging station.

A. Energy Charge

Per kWh as measured by the EV charging station meter or Company billing meter:

Level 2 EV Charging Station Energy Charge (Per kWh):	\$0.12413
Level 3 EV Charging Station Energy Charge (Per kWh):	\$0.13243

B. Session Charge (Optional)

EV Charging Station Session Charge (Per hour):	\$0.00 - \$6.00

A Session shall be defined as the period of time an EV is connected to the EV charging station. The Session Charge is an option that can be implemented at the discretion of the Host and Company to promote improved utilization of the EV charging station(s) located upon their premise.

PUBLIC ELECTRIC VEHICLE CHARGING STATION SERVICE
Schedule CCN (Continued)

The optional Session Charge will be configured within the following guidelines as either Charge-Based or Time-Based at the discretion of the Host.

(i) Charge-Based – A charge-based Session Charge would start when the EV has stopped charging (but is still connected to the EV charging station) plus a defined grace period. The grace period allows the user time to end the Charge Session and move the EV.

(ii) Time- Based – A time-based Session Charge would start at either the time of initial plug-in of the EV or a predefined time in an active Charge Session (*e.g.*, two hours after initial plug-in) at the Host's discretion and may increase to a higher rate at a subsequent predefined time in an active Charge Session (*e.g.*, four hours after initial plug-in).

Session Charges for fractional hours will be prorated. The Session Charge rate may not exceed $6.00 per hour.

BILLING:

All users of the Company's public EV charging stations must have an account with the Company's third party vendor. Information on opening an account can be found on the Company's website at http://kcpl.chargepoint.com/.

All charges applicable to any user of an EV charging station under Billing Option 1 or 2 will be billed directly through the Company's third party vendor. All charges applicable to the Host under Billing Option 1 will be billed directly through the Company.

DEMAND SIDE INVESTMENT MECHANISM RIDER:

Subject to Schedule DSIM filed with the State Regulatory Commission.

FUEL ADJUSTMENT:

Fuel Adjustment Clause, Schedule FAC, shall be applicable to all customer billings under this schedule.

TAX ADJUSTMENT:

Tax Adjustment, Schedule TA, shall be applicable to all customer billings under this schedule.

REGULATIONS:

Subject to Rules and Regulations filed with the State Regulatory Commission.