Exhibit No.:	
Issue:	Fuel Adjustment Clause; DSIM Rider: Transmission and Critical Infrastructure Protection; Consolidation of L&P and MPS Rate Jurisdictions; Lake Road Allocations; Jeffrey Energy Center In-Service
Witness:	Tim M. Rush
Type of Exhibit:	Direct Testimony
Sponsoring Party:	KCP&L Greater Missouri Operations Company
Case No.:	ER-2016-0156
Date Testimony Prepared:	February 23, 2016

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO.: ER-2016-0156

DIRECT TESTIMONY

OF

TIM M. RUSH

ON BEHALF OF

KCP&L GREATER MISSOURI OPERATIONS COMPANY

Kansas City, Missouri
February 2016

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

DIRECT TESTIMONY

OF

TIM M. RUSH

Case No. ER-2016-0156

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") as Director, Regulatory Affairs.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of KCP&L Greater Missouri Operations Company ("GMO" or the "Company").

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 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 proceedings 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. Address the Company's request to continue the Fuel Adjustment Clause ("FAC");

   a. Address changes to the FAC tariff;

   b. Address the Company's proposal to remove the cost for the St. Joseph landfill from recovery through the FAC to recovery through the Renewable Energy Standard Recovery Adjustment Mechanism ("RESRAM");

II. Address the Company's request to change the current MEEIA tariff from recovery through the current tracker mechanism to full recovery through a DSIM rider;

III. Address the Company's request to recover transmission and critical infrastructure protection ("CIP") and cyber-security expenses in this case;

IV. Support the Company's proposal to consolidate the MPS and L&P rate jurisdictions by;

a. Rate Design;

b. Class Cost of Service Study.

V. Explain and support the Company's allocation of Lake Road plant and expenses between electric and steam operations as a result of the cessation of the use of coal at the Company's Boiler 6 unit; and

VI. Explain and support the completion of a major project at Jeffrey Energy Center.

I. FUEL ADJUSTMENT CLAUSE FILING REQUIREMENTS

Q: Does the Company currently have an approved FAC?

A: Yes. The FAC was initially approved for GMO in Case No. ER-2007-0004 on May 17, 2007. Several modifications and clarifications have been made to the FAC in subsequent rate cases; ER-2009-0090, ER-2010-0356 and ER-2012-0175. The Company recently completed its seventeenth accumulation period of June 2015 – November 2015. The Commission has approved the tariff change which will become effective March 1, 2016. This recovery of the seventeenth accumulation period will be from March 2016 – February 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-6.

Q: Are you providing any other support for continuation of your FAC?

A: Yes. 4 CSR 240-20.090 (9) requires a line loss study be conducted no less than every four (4) years to be used in the general rate proceeding necessary to continue to utilize a RAM. See Schedules TMR-7 through TMR-8 for excerpts from the study containing the energy loss factors used in the tariffs. The entire line loss study will be included as workpaper support of this testimony.

Q: Has the Company met all of the filing requirements to continue the FAC in 4 CSR 240-20.090 and 4 CSR 240-3.161?

A: Yes.

Q: Is the Company requesting to continue the FAC?

A: Yes. The FAC applies to fuel and purchased power expenses, including a credit for off system sales revenues.

Q: Is the Company proposing to make any changes in the FAC tariff?

A: Yes, the Company is proposing several changes. The most significant change is to consolidate the two rate jurisdictions into one rate to coincide with the overall proposed rate design consolidation being presented in this case. Currently, each rate jurisdiction has its own FAC rate that is adjusted twice a year. Many changes have occurred since the establishment of each rate jurisdiction’s FAC. While GMO has added generation resources that required determining allocations between jurisdictions, so as to assign the generation resources and operating expenses, as well as fuel, GMO has also had purchased power agreements expire. All of these changes require specific planning for each jurisdiction. The most significant change to GMO has been the implementation by SPP of the Integrated Marketplace, which has resulted in selling and purchasing all of the generation needs for GMO. Essentially, the Integrated Marketplace establishes further economic benefits to GMO and each rate jurisdiction.

Additionally, the Company is proposing that all costs for the transmission of electricity by others (with the exception of certain transmission costs related to the Crossroads generating station that have previously been disallowed by the Commission, as discussed in more detail in the Direct Testimony of GMO witnesses John Carlson, Burton Crawford and Scott Heidtbrink) be included in the FAC. These costs represent the transportation of electricity, are largely outside the control of the Company, and are volatile. GMO proposes to use forecasted transmission expenses and revenues to the extent any transmission revenues and expenses are not covered by the FAC. Similarly, if the Commission rejects GMO's request for inclusion of 100% of transmission expenses and revenues in the FAC, and also rejects GMO's request for forecasted transmission revenues and expenses, then GMO requests a tracker.

Q: Are there any other changes you are proposing to the FAC?

A: Yes. In the Company's last rate case, it received a variance to allow it to recover the cost of the St. Joseph landfill gas project fuel costs through the FAC. The RESRAM rules found in 4 CSR 240-20.100 (6)(A)16 state that Renewable Energy Standard ("RES") compliance costs can only be recovered through a RESRAM or as part of a general rate proceeding not through an FAC. In this case, the Company proposes to shift the fuel costs associated with the St. Joseph land fill from the FAC to be included in the 182513 deferred account and recovered through the RESRAM rate that is currently being charged to customers. We are not proposing to change the RESRAM rate in this case but propose to allow it to continue as set out in the rules for the RESRAM. The current RESRAM rate was implemented in December 1, 2014, and was initially established as recovery of 1% of the Company's revenue. Additionally, in the last rate case with KCP&L where an FAC was initiated, unit train costs, including both lease and maintenance costs were included in the FAC. This was consistent with other utilities' FAC recovery mechanisms. I am recommending that these costs be included in the GMO FAC in this proceeding.

Q: Are you proposing any other changes to the FAC?

A: Yes. The proposed FAC tariff for GMO incorporates many of definitions now found in the KCP&L FAC tariffs.

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 and purchased power costs and transmission costs net of off system sales and transmission revenues above a base amount that is included in base rates, but also provides customers assurance that GMO is not over-recovering net fuel and purchased power costs. The FAC is needed to help address volatile and uncertain 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. The net fuel and purchased power and transmission costs for GMO represent approximately 30% of the overall costs of serving customers.

Q: Do you believe that the absence of an FAC is potentially harmful to the Company and/or the Customer?

A: Yes. Without the proposed FAC, under increasing costs scenarios, the Company would not have a reasonable opportunity to earn the rate of return authorized in this case. Conversely, if net fuel and purchased power and transmission costs turn out to be lower after the setting of base rates, then the presence of an FAC will protect customers from paying higher prices than the Company's actual experience. For example, the current FAC is actually a credit back to customers because the FAC is below the base. This serves as GMO's explanation, compliant with Commission rule 4 CSR 240-3.161(3)(E), of how the FAC proposed by GMO is designed to provide GMO with a sufficient opportunity to earn a fair return on equity.

II. DEMAND SIDE INVESTMENT MECHANISM ("DSIM") RIDER

Q: What is the Company requesting in this proceeding?

A: GMO is requesting to modify the current tariffs in such a way as to eliminate the current tracker component of the DSIM recovery mechanism and change it to a rider. As such, the rate and all balances going forward would be reflected in the DSIM rider.

Q: Was this change previously contemplated?

A: Yes. In the initial MEEIA plan for GMO, Case No. EO-2012-0009, the parties entered into a Stipulation and Agreement that contemplated moving the current tracker mechanism to a rider (found in paragraphs 6 & 7). Additionally, in the recent Stipulation and Agreement entered into in Case No. EO-2015-0241, parties agreed to a recovery mechanism that blended the current tracker in base rates with a rider to form the rate that will be charged until the conclusion of this case, at which time the plan is to eliminate the tracker component and have a full rider mechanism. This would separate the current MEEIA recovery mechanism from a tracker to a rider mechanism beginning with new rates from this proceeding.

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

A: GMO has calculated the remaining balances in the amortization from pre-MEEIA expenses and has reflected that rate in the tariff addressing pre-MEEIA opt-outs.

III. TRANSMISSION EXPENSE AND CRITICAL INFRASTRUCTURE PROTECTION and CYBER-SECURITY EXPENSE

Q: Do the rate case procedures normally used in Missouri provide a sufficient mechanism for GMO 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 certain costs have been increasing rapidly and billing determinants that drive revenues (i.e., average customer use) are flat to declining, the opportunity for GMO to earn a fair return is severely compromised by regulatory lag. Company witness Albert Bass presents information pertaining to the slowing growth being experienced at GMO. 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 GMO's ability to earn its authorized return on equity is hindered. A rate case in Missouri typically takes approximately 11 months to complete. GMO's cost of service has been increasing since the conclusion of its last rate case primarily caused by SPP transmission costs increases. Additionally, the necessity to both invest capital and incur expenses to maintain and improve reliability and safety has become significant and are anticipated to grow even further in the coming years.

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

A: Yes. In this case, the Company is specifically asking for inclusion of transmission costs and revenues in the FAC, or in the alternative, for recovery of forecasted costs attributable to both transmission costs and CIP/cyber-security costs.

Q: Why is approval of forecasted costs for transmission and CIP/cyber-security in this case so important?

A: One of responsibilities of the Commission is to oversee the establishment of rates, which are designed to allow the Company an opportunity to earn a reasonable return on its investment and recover its cost of service in serving customers. In order to do this, a historical test period has been traditionally used for purposes of evaluating the cost of service, adjusting for known and measurable changes. The adjustments to the historical test period are critical and are used as a basis for establishing rates that would allow the Company an opportunity to earn a reasonable return when the new rates go into effect and thereafter. Without forward-looking rate treatment to timely recover these cost increases, GMO will not have a reasonable opportunity to earn its authorized return on equity when the rates are set in the case and in effect.

GMO will devote substantial resources to CIP/cybersecurity efforts over the next few years that are intended to protect customers. To knowingly not allow the utility to recover these costs is patently unfair to the utility. Joshua F. Phelps-Roper addresses these efforts and costs in more detail in his Direct Testimony.

GMO has for some time now seen large escalations in transmission costs. As seen in the Direct Testimony of John Carlson, these costs are expected to continue to increase. GMO's preferred approach to recovery of transmission costs is where all costs and revenues are included in the FAC. In fact, GMO filed the FAC to reflect transmission costs and revenues in the FAC. But, to the extent that the proposal is rejected by the Commission, then GMO proposes to use forecasted transmission expenses to set rates.

For both CIP and cybersecurity costs and transmission expenses, if the forecasted costs during the period in which rates are in effect are lower than those costs in rates, the Company would return the excess to customers in the next rate case. However, if costs are more than those forecasted, the Company's shareholders would absorb those costs exceeding the rate allowance.

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

A: The effect of regulatory lag in the traditional ratemaking process means that GMO will always face a time lag in recovering cost increases. Because of GMO's current low to no growth revenue environment and the magnitude of the cost increases identified in the transmission and CIP/cyber-security area, failure to recover a reasonable forecast of those increased costs will have a significant adverse impact on the Company's earnings.

Such under-recovery of costs, over time, would undermine GMO's financial health and access to capital markets, potentially increasing the cost to customers by paying higher capital costs or potentially jeopardizing GMO's ability to maintain service levels and invest in its system. In addition to adversely affecting earnings, an under-recovery of costs compromises the Company's cash flows, straining its financial health and limiting its access to credit. GMO, through Great Plains Energy, competes for credit with other vertically integrated electric utilities in the Midwest and throughout the country, the vast majority of which already make use of other recovery mechanisms which better match cost recovery and cost incurrence.

IV. RATE CONSOLIDATION

Q: In this case, the Company is proposing to consolidate the two rate jurisdiction. Would you describe these two jurisdictions?

A: Yes. GMO is made up of two rate jurisdictions, L&P, which was formerly the St. Joseph Light & Power Company and MPS, which was the former Missouri Public Service Company. Both electric rate jurisdictions were under the former Aquila umbrella and were purchased by Great Plains Energy and renamed to KCP&L Greater Missouri Operations Company.

Q: Why are you proposing to consolidate these two rate jurisdictions in the proceeding?

A: As presented in the direct testimony of Company witness Bradley D. Lutz, the Company agreed in the previous case, Case No. ER-2012-0175, to study the potential consolidation of these two jurisdictions. As the Company proceeded down the path of evaluating the potential consolidation, it became apparent that would be very feasible to consolidate the rates because the overall rates charged to customers for each jurisdiction were very close to each other.

Additionally, benefits can be achieved through the consolidation of rates. They include the consolidation of the fuel adjustment clause as mentioned above in the discussion of the FAC. Also, the benefits of customer communications, as well as it will become easier to explain rates for one company, rather than the two jurisdictions. It also provides benefits to business practices and record keeping which currently require multiple allocations to keep the records for each rate jurisdiction.

The one area that should benefit the most is that the Company will be able to align rates for each jurisdiction to a single set of rates. Currently, each jurisdiction has different rate elements for each customer category. By consolidating rates, the Company is able to standardize the rates into a consistent set of rate elements.

IV. LAKE ROAD ALLOCATIONS

Q: In this case, are you recommending changes to the allocation between the industrial steam and electric operations at the Lake Road Plant?

A: Yes. As a result of substantial changes at the Lake Road Plant, it was necessary to modify the allocations methodology to fit the current and future operating characteristics of the plant.

Q: Would you describe the industrial steam and electric operations at the Lake Road Plant?

A: Yes. The Lake Road Plant provides electric generation serving GMO with multiple units which burn coal, natural gas and fuel oil. The Lake Road Plant also serves 5 industrial steam customers that take steam service from the Lake Road 900 lb. side of the plant. The 900 lb. side of the plant consists of 6 boilers, numbered 1 through 5 and 8. Boiler 5 is capable of burning coal, natural gas or fuel oil. Boilers 1 through 4 and 8 can burn either natural gas or fuel oil. The 900 lb. side also produces electricity from 3 electric turbines supported by the above mentioned boilers. Lake Road also has an 1800 lb.

system that consists of 1 boiler and 1 turbine. The 1800 lb. system is capable of burning coal, natural gas or fuel oil. The remainder of the plant is made up of 3 combustion turbines. The Company will cease operation of the 1800 lb. system on coal in June of this year to help in compliance with the EPA requirements. This change in operations will have a significant impact on the overall operations of the plant and is one of the reasons for changing the method for allocating costs at the Lake Road Plant between the industrial steam and electric jurisdictions.

Q: Are there other reasons why you are recommending changes to the allocations between the steam and electric utility services?

A: Yes. Outside influences to the operations of the Lake Road Generating Station in recent year have changed how the units at the Lake Road Plant are dispatched for electricity. Some of these drivers are the increased use of wind generation in the area, abundance of natural gas along with lower gas prices and the Southwest Power Pool's (SPP) launch of the Integrated Marketplace required by FERC on March 1st of 2014.

Current electric dispatching by the SPP for the 900 lb. side is typically for, peak generation, ancillary services and spinning reserve. When the units are online, they are operated at low loads. This results in multiple turbines and boilers being operated at low loads to cover the potential for full load generation.

The Company has determined that due to the way that SPP is dispatching the 900 lb. side, that the current steam demand allocation factor should be changed to reflect how the plant is now being utilized. Currently the 900 lb. steam demand allocation factor is based on a percentage of maximum steam sales over the sum of maximum steam sales and generation. The maximum steam sales and generation includes sales to industrial steam customers and electric generation on the 900 lb. side.

With the changes at Lake Road and the SPP environment, a more accurate method to determine the 900 lb. steam demand allocation factor should consider the maximum steam sales demand and the electric demand capability of the steam turbines. By taking the maximum steam sales demand in the summer and dividing the sum of the maximum steam sales demand in the summer and the capability of the steam turbines demand for electric generation, the percentage would be representative of the percent of steam demand for the 900 lb. side. This method will better reflect how the 900 lb. plant is currently maintained and operated and better recognized the potential for full load generation. Below is a description of the allocation methodology we are proposing in this case.

900 lb ELECTRIC/STEAM DEMAND ALLOCATION FACTOR

1a. Determine the maximum coincident peaks of the steam sales customers in mmBtu/Hr in a 5 year period for the past 5 years during the months of July and August. This produces 10 individual monthly peaks. Take the average of these peaks and multiply by a weighted average boiler efficiency of 81.5% to convert to a calculated fuel in mmBtus/Hr needed to support steam sales by the Lake Road Boilers. This number represents the Calculated Fuel for Steam Sales ($Fuel_{Steam}$) Average Peak hour in mmBtus/hr.

1b. To Determine the amount of mmBtus/Hr of fuel needed to support full electric load on the 900 lb. steam turbines, take the capability rating in gross MWs for each turbine, (1, 2 and 3) and multiply by their respective gross turbine heat rate and multiply by a weighted average boiler efficiency of 81.5 %. Add these three numbers together to obtain the fuel energy in mmBtus/Hr needed to operate the 900 lb. turbines at full electric load. This number represents the Calculated Fuel for Max Electric Generation ($Fuel_{Gen\ potential}$) for the 900 lb. Steam Turbines in mmBtus/Hr.

1c. To determine the 900 lb. Steam Demand Allocation Factor, divide the Calculated Fuel for Steam Sales Average Peak hour ($Fuel_{Steam}$) in mmBtu/hr by the sum of the Calculated Fuel for Steam Sales Average Peak ($Fuel_{Steam}$) and the Calculated Fuel for Max Electric Generation ($Fuel_{Gen\ potential}$) for the 900 lb. Steam Turbines in mmBtus/Hr and convert to percent. 1 minus the result would be the electric allocation factor.

1800 LB. Unit 4/6 Coal Cessation Description

Unit 4/6 is an electric generating unit with a net rating of 96.8 MW located in KCP&L's GMO territory at its Lake Road Generating Station in St. Joseph, MO. Unit 4/6 is comprised of Turbine-Generator 4 and Boiler 6. Currently, Boiler 6 is capable of full load on coal or natural gas, with coal being the primary fuel. The boiler can be co-fired with a combination of these two fuels.

To comply with upcoming environmental regulations we have decided to cease burning coal on April 15, 2016. At that time we will change to natural gas as our primary fuel. Additionally, fuel oil capability will be added to the boiler as a back-up fuel, which will primarily be used during the winter season when gas availability can be limited.

The driver for switching Unit 4/6 from coal to natural gas was a combination of existing and expected future environmental regulations. The first regulation impacting the decision to switch the boiler to natural gas was EPA's Mercury and Air Toxics

Standards (MATS). In order for Unit 4/6 to comply with that regulation, pollution control upgrades were needed to further reduce both mercury and particulate emissions. By switching the unit to natural gas, Unit 4/6 will not be impacted by MATS. In addition, EPA's Cross – State Air Pollution Rule (CSAPR) and the Clean Air Interstate Rule (CAIR) regulations placed tighter controls on emissions of sulfur dioxide (SO_2). To comply with CSAPR and CAIR the options for Unit 4/6 were to either install controls to reduce SO_2 emissions, purchase SO_2 allowances in the open market, or switch to natural gas. In the past Lake Road has complied with similar regulations by purchasing allowances, however there is much more uncertainty about the availability and price of SO_2 allowances under CSAPR and CAIR.

In addition to the current regulations impacting Unit 4/6, several significant potential future regulations are in various forms of development that would impact continued operation of the boiler using coal. Modifications to the Particulate Matter and SO_2 National Ambient Air Quality Standards (NAAQS) are being tightened. The impacts on Unit 4/6 have been predicted to go in to affect in 2022 requiring the potential installation of an SO_2 scrubber and fabric filter to allow continued compliance. Besides the capital costs for installing the equipment, additional costs are incurred with having to deal with the by-products created, primarily the scrubber sludge. Lake Road's limited available land area for handling the scrubber sludge greatly increases the costs to continue to burn coal on Unit 4/6. Based on modeling of these various options and future generation predictions, the least cost option was to switch to natural gas.

LAKE ROAD PLANT UTILIZATION FACTOR

The Lake Road Plant allocation factor currently used is based on coal use of the entire plant. Similar to the 900 lb. electric/steam allocation factor, it is currently based on the coal use for steam customers as the numerator. The denominator is the total coal use of the Lake Road Plant. This would include the 900 lb. and 1800 lb. side of the plant. As we have discussed, with the cessation of coal on Unit 4/6 for electric generation, this allocation methodology would no longer be appropriate.

We have developed a whole plant allocation methodology to replace the no longer available coal usage allocation methodology. To calculate the whole plant allocation methodology, we take the plant and reserve balances identifying those that are specifically steam as well as specifically electric related. We then allocate the remaining plant and reserve balances by the 900 lb. steam demand allocation factor described above. Specifically identified steam plant/reserve is added to the steam portion of the remaining plant as allocated.

Q: Has the Company made any changes to the administrative and general ("A&G") and operations and maintenance ("O&M") allocation factors used to allocate expenses between electric retail and industrial steam services?

A: No, the A&G and O&M costs continue to be calculated as in the past using the new demand and whole plant allocation factors in place of the previous demand and coal burn factors as described above.

V. JEFFERY ENERGY CENTER

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

A: The purpose is to provide, on behalf of GMO, the Jeffrey Energy Center ("JEC") Unit 1 confirmation of construction completion and in-service criteria compliance.

Q: Please describe the relationship between GMO and JEC.

A: JEC is a jointly owned coal fired facility consisting of three units (720 mW/each nominal capacity) that went into service in: 1978, 1980, and 1983, respectively. GMO owns eight percent of JEC and Westar Energy ("Westar") owns eighty-four percent of the facility and leases the remaining eight percent.

Q: Please describe the NOx emission reduction project at JEC and the decision process.

A: As part of the Westar response to the March 26, 2010 Consent Decree between the United States of America and Westar Energy, Inc., NOx emission reduction equipment was evaluated, budgeted, constructed, and installed on JEC Unit 1. The installed equipment included a selective catalytic reduction ("SCR") system, induced draft ("ID") fans, ID fan variable frequency drive ("VFD") and motor, ammonia storage and supply, and main auxiliary power transformer.

Q: Is the JEC Unit 1 SCR complete?

A: Yes, the JEC Unit 1 SCR became operational in December 2014.

Q: Is the JEC Unit 1 SCR in-service?

A: Yes, in accordance with the criteria jointly developed with the MPSC Staff, the JEC Unit 1 SCR completed all required testing on March 21, 2015 and was placed in service in GMO's accounting records. The resulting criteria and the associated performance tests are attached as TMR-9.

Q: Was any additional equipment required at JEC to meet the Consent Decree?

A: Yes, a selective non-catalytic reduction ("SNCR") system and smartburn system was installed on JEC Unit 2 as contemplated in the Consent Decree.

Q: Is the JEC Unit 2 equipment complete?

A: Yes, the JEC Unit 2 SNCR system and smartburn system were placed into operation on June 2, 2014.

Q: Was in-service testing and criteria necessary for this equipment to be placed in service in GMO's accounting records?

A: The scope and cost of the installation was not sufficient to warrant the use of in-service testing criteria to place the equipment in service. JEC's operations engineering staff was responsible for the oversight of the installation valued at approximately $2M, GMO's eight percent share.

Q: Does that conclude your testimony?

A: Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement A General Rate Increase for Electric Service	)))	Case No. ER-2016-0156

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 KCP&L Greater Missouri Operations Company consisting of nineteen (19) 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 23rd day of February, 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.
As discussed in the Direct Testimony of Company Witness Bradley D. Lutz in this case, the Company is filing tariffs which consolidate the rates for the two GMO territories of MPS and L&P. Schedule TMR-4 presents what the proposed FAC rate schedules would look like if the consolidation of the territories were not approved by the Commission in this case.

(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-2012-0175. The changes proposed in this filing are for the amounts contained in base rates as well as the addition of transmission costs/revenues in the clause. Some key features of the FAC include:

- The FAC factor is based upon historical differences between the cost of fuel, energy and transmission costs and fees from SPP net of off-system sales revenue and transmission revenues built into base rates and the actual amounts of these net costs.
- There is 95% recovery of the difference between these actual costs and the amounts built into base rates.
- Items considered in the FAC are non-labor generating plant fuel costs, purchased power energy and short-term capacity charges, emission allowance costs, transportation costs, hedging costs, and transmission costs. These costs are offset by off system sales revenues, the revenues from the sale of renewable energy credits as well as transmission revenues. The Day 2 market for Southwest Power Pool (SPP) began in early 2014. As a result, generation is bid into the SPP market and retail load

is purchased from the retail market. 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 proposed base amount for KCP&L GMO combined FAC base rate is $0.02404 per kWh.
- The re-based amount for separate MPS/L&P jurisdictions would be $.02455 and $.02262 per kWh respectively.

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

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. Allowance costs are included in FERC account 509. Fuel used in other power generation (Combustion Turbines) is included in FERC account 547. Purchased Power is in FERC account 555. Transmission of electricity by others is included in FERC account 565. Scheduling, system control and dispatch services are included in FERC account 561.4. Reliability, planning, and standards development services are included in FERC account 561.8. Market facilitation, monitoring and compliance services are included in FERC account 575.5. Regulatory commission expense for FERC assessments is included in FERC account 928. Sales for resale are recorded in FERC account 447. Transmission Revenue from Others is recorded in 456. The following six digit Company accounts expand from the FERC accounts, representing native load (NL) and sales for resale (SFR), and are included in the FAC.

General Ledger Account/Resource	Expense
501000/6000	NL Bit Coal and Freight Costs (Variable)
501000/6005	NL PRB Coal and Freight Costs (Variable)
501000/6030	NL Tire Costs (Variable)
501000/6001	NL Bit Coal Inventory Adj.
501000/6006	NL PRB Coal Inventory Adj.
501000/6035	NL Biofuels
501020	NL Coal and Freight Costs (Variable)
501000/6002	NL Bit Coal Freeze & Dust Treatment
501000/6007	NL PRB Coal Freeze & Dust Treatment
501030	SFR Coal & Freight Costs
501000/6016	NL Oil Costs
501000/6018	NL Oil Inventory Adj.
501000/6020 - 6024	NL Gas
501000/6026	Hedge Settlements
501000/6027	NL Gas Adjustments
501000/6017	NL Propane
501000	Unit Train (Rail) Lease
501300	NL Additives
501400	NL Residuals Costs
501420	NL Residuals Costs
501450	NL Residuals Costs
504100	Contra-Steam Coal, Gas, Oil
509000	Emission Allowances

509000	Renewable Energy Credits (Sale of RECs)
547000/6016	NL Oil
547000/6020 - 6024	NL Gas Costs & Transportation (Variable)
547000/6027	NL Gas Adjustments
547000/6018	NL Oil Adjustments
547000/6026	Hedge Settlements
547000/6035	NL Biofuels
547020	NL Gas Costs & Transportation (Variable)
547030	SFR Gas Costs & Transportation (Variable)
555000, 555021	NL Purchased Power-Energy
555005	Purchased Power-Capacity (Short-term ONLY)
555030, 555031	SFR Purchased Power-Energy
555035	SFR Purchased Power – WAPA
561400	Trans OP LD Dispatch Control & Dispatch
561800	Trans OP LD Dispatch Reliability Planning RTO
565000	Trans OP Trans of Elec by Others
565020	Trans OP Trans Res Load CHG
565027	Trans OP Trans by Other Demand
565030	SFR Transmission
575700	Trans OP MKT MON&COMP SER RTO
928000/Dept 415	Regulatory Commission Expense (FERC assessments)

General Ledger Account	Revenue
447002	Bulk Power Sales
447012	Wholesale Sales Capacity (Short-term ONLY)
447030	SFR Off-system Sales
447035	SFR Off System Sales – WAPA
456009	Other Rev Transmission
456100	Revenue Trans Elec for Others
456109	Other Elec Rev Transmission

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

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

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

General Ledger Account/Resource	Revenue
440001/5500	Residential Electric Revenue
442001, 442101/5500	Commercial Electric Revenue
442201-442202/5500	Industrial Firm Electric Revenue
444001-444002/5500	Sales Street Lighting
445001/5500	Sales Public Authority Electric

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

General Ledger Account	Revenue
440001/5525	Residential Electric Revenue FAC Rcvy
442001, 442101/5525	Commercial Electric Revenue FAC Rcvy
442202/5525	Industrial Firm Electric Revenue Rcvy
444001-444002/5525	Sales Street Lighting FAC Rcvy
445001/5525	Sales Public Authority Electric FAC Rcvy

Current period over/under accrual FAC revenues are booked as defined above as Total FAC Actual Energy Costs less Base Energy Costs times 95% with the resulting accrual offset in General Ledger Account 182380, Accrued Fuel Clause. The over/under accrued FAC revenues is booked to a separate set of revenue accounts, as follows:

General Ledger Account	Revenue
440001/5520	Residential Electric Revenue FAC Unbilled
442001, 442101/5520	Commercial Electric Revenue FAC Unbilled
442202/5520	Industrial Firm Electric Rev FAC Unbilled
444001-444002/5520	Sales Street Lighting FAC Unbilled
445001/5520	Sales Public Authority Electric FAC Unbill

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-2007-0004 issued May 17, 2007, the Commission explains the reasoning for allowing only 95% of FAC eligible costs to be collected from customers,

"The Commission also finds after-the-fact prudence reviews alone are insufficient to assure Aquila will continue to take reasonable steps to keep its fuel and purchased power costs down, and the easiest way to ensure a utility retains the incentive to keep fuel and purchased power costs down is to not allow a 100% pass through of those costs.

The Commission finds allowing Aquila to pass 95% of its prudently incurred fuel and purchased power costs, above those included in its base rates, through its fuel adjustment clause is appropriate. With a 95% pass-through, the Commission finds Aquila will be protected from extreme fluctuations in fuel and purchased power cost, yet retain a significant incentive to take all reasonable actions to keep its fuel and purchased power costs as low as possible, and still have an opportunity to earn a fair return on its investment." (page 54)

"The Commission concludes that a 95% pass-through would not violate Section 386.266.4(1), in that it would still afford Aquila a sufficient opportunity to earn a fair return on equity." (page 55)

The 95% pass-through feature remained unchanged in the settlement of Rate Case. Nos. ER-2009-0090, ER-2010-0356 and ER-2012-0175.

(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 contained in the Risk Management Policy.

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

The Company proposes to consolidate the two rate jurisdictions known as L&P and MPS, including the FAC and the ongoing FAC recovery mechanism. The RAM base amount reflected in the rate proposal was developed by using weather normalized and customer annualized unit sales, demands and system requirements for customers of the combined rate jurisdictions as of the test period updated to reflect the proposed true-up in the case. The system requirements and demands were then run through a production cost model to determine the fuel, purchased power net of off-system sales. Transmission costs and revenues were then added to develop an overall RAM for the test period updated through the true-up. Those costs were reflected in the class cost of service study supported by Company witness Bradley D. Lutz and were allocated to the classes based on energy allocation factors in the class cost of service.

The proposed RAM reflected in the rate designed proposed in this case was a rebase of the fuel, purchased power and transmission costs less off-system sales and transmission revenues, adjusted for losses assigned to each rate based on energy. The FAC allocates cost by voltage level using commission approved allocation methods.

The Company proposes semi-annual adjustments to the FAC which reflect changes to the base amount included in rates. The plan for the FAC is reflected in the FAC tariffs contained in this case filing.

(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:

Transmission costs and revenues have been added to the FAC. The base rate has been updated, and the 5% sharing amount has been updated. Any changes to account coding that have occurred since the last rate case filing have been updated. Landfill gas costs have been removed from the FAC. Propane costs in account 501 have been added into the FAC. Adjustments have been made to accommodate the information needed to support a combined set of GMO tariffs while also providing information on MPS and L&P individually.

(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:

See Direct Testimony of Burton L. Crawford.

(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-2012-0175.

Important Notice

KCP&L Greater Missouri Operations Company (“Company” or “GMO”) has filed a rate increase request with the Missouri Public Service Commission (“PSC”). The increase would total approximately _____ percent in the Missouri Retail Service Area.

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 PURCHASED POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided January 26, 2013 Through Effective Date of Rate Tariffs for ER-2016-0156)

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 January 25, 2017, the two corresponding twelve-month recovery periods and the filing dates are as shown below. Each filing shall include detailed work papers in electronic format to support the filing.

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

A recovery period consists of the billing 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, emission allowance costs 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 Southwest Power Pool (SPP) revenues and costs, revenue from the sale of Renewable Energy Certificates or Credits (REC), and emission allowance revenues collected during the accumulation period. Eligible costs do not include the purchased power demand costs associated with purchased 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.

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

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASED POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided January 26, 2013 Through Effective Date of Rate Tariffs for ER-2016-0156)

FORMULAS AND DEFINITIONS OF COMPONENTS

FPA = 95% * ((ANEC – B) * J) +T + I + P

95% = Customer responsibility for fuel variance from base level.

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

FC = Fuel Costs Incurred to Support Sales:

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

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

E = Net Emission Costs:

The following costs and revenues reflected in FERC Account Numbers 509, 411.8 and 411.9: emission allowance costs offset by revenues from the sale of emission allowances including any associated hedging costs, and broker commissions, fees, commodity based services, and margins.

PP = Purchased Power Costs:

The following costs or revenues reflected in FERC Account Number 555: purchased power costs, capacity charges for capacity purchases less than 12 months in duration, energy charges from capacity purchases of any duration, settlements, insurance recoveries, and subrogation recoveries for

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASED POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided January 26, 2013 Through Effective Date of Rate Tariffs for ER-2016-0156)

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

purchased power expenses, virtual energy charges, generating unit price adjustments, load/export charges, energy position charges, ancillary services including penalty and distribution charges, hedging costs, broker commissions, fees, and margins, SPP EIS market charges, and SPP Integrated Market charges.

TC = Transmission Costs:
The following costs reflected in FERC Account Number 565 (excluding Base Plan Funding costs and costs associated with the Crossroads generating station): transmission costs that are necessary to receive purchased power to serve native load and transmission costs that are necessary to make off system sales.

OSSR = Revenues from Off-System Sales:
The following revenues or costs reflected in FERC Account Number 447: all revenues from off-system sales but excluding revenues from full and partial requirements sales to Missouri municipalities that are associated with GMO, hedging costs, SPP EIS market charges, and SPP Integrated Market revenues.

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

Hedging Costs = 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 purchased power costs, 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, and swaps.

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

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASED POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided January 26, 2013 Through Effective Date of Rate Tariffs for ER-2016-0156)

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

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

L&P S_{AP} x Base Factor (BF)
MPS S_{AP} x Base Factor (BF)

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

J = Missouri Retail Energy Ratio = Retail kWh NSI/S_{AP}
Where: total system kWh equals retail and full and partial requirement NSI associated with GMO.

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 below.

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

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASED POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided January 26, 2013 Through Effective Date of Rate Tariffs for ER-2016-0156)

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

Where:

FPA = Fuel and Purchased Power Adjustment

S_{RP} = Forecasted recovery period 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

The FPA will be calculated separately for L&P and MPS, and by voltage level, and the resultant FAR will be applied to the bills of customers in the respective rate districts and voltage levels.

BASE FACTOR (BF)

Company base factor costs per kWh:
$0.02076 for L&P
$0.02278 for MPS

TRUE-UPS

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

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

PRUDENCE REVIEWS

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

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASED POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided Effective Date of Rate Tariffs for ER-2016-0156 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 January 21, 2021, the two corresponding twelve-month recovery periods and the filing dates will be as shown below. Each filing shall include detailed work papers in electronic format to support the filing.

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

A recovery period consists of the months during which the FAR is applied to 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 contacts 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 $.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 PURCHASED POWER ADJUSTMENT ELECTRIC
(Applicable to Service Provided Effective Date of Rate Tariffs for ER-2016-0156 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 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], applicable taxes, natural gas costs, alternative fuels (i.e. tires, bio-fuel), fuel quality adjustments, fuel hedging costs, fuel adjustments included in commodity and transportation costs, broker commissions 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, propane costs, 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;

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

Subaccount 501300: fuel additives and consumable costs for Air Quality Control Systems (“AQCS”) operations, such as ammonia, hydrated lime, lime, limestone, powder activated carbon, urea, sodium bicarbonate, trona, 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 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

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

(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.

TC = Transmission Costs and Revenues:

The following costs reflected in FERC Account Number 561:

Subaccount 561400: all RTO scheduling, system control, dispatching services, and NERC fees;

Subaccount 561800: all RTO reliability, planning and standards 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;

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FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

The following revenues 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

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.

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.,

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<u>FORMULAS AND DEFINITIONS OF COMPONENTS</u> (continued)

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;

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

FORMULAS AND DEFINITIONS OF COMPONENTS (Continued)

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.

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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

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FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

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

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
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.

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FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

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. Net 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: $0.02404

J = Missouri Retail Energy Ratio = Retail kWh sales/total system kWh
Where: total system kWh equals retail and full and partial requirement sales associated with GMO.

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

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FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

Where:

FPA = Fuel and Purchased Power Adjustment

S_{RP} = Forecasted recovery period 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

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.

COMBINED TARIFFS

On a go forward basis, rates will no longer be reflected as separate MPS and L&P territory rates, but rather on a GMO Total Company basis. In order to achieve this, a true-up will be performed that rolls any over or under recovered costs into the next open accumulation period, as reflected in the new combined tariff sheets (see sheet 127.12).

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:			Month dd, yyyy
			GMO
1	Actual Net Energy Cost (ANEC) = (FC+E+PP+TC-OSSR-R)		$0
2	Net Base Energy Cost (B)	-	$208,067,920
	2.1 Base Factor (BF)		$0.02404
	2.2 Accumulation Period NSI (S_{AP})		8,655,768,000
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_{Prim} = FAR x VAF_{Prim}		$0.00000
15	Prior Period FAR_{Prim}	+	$0.00000
16	Current Annual FAR_{Prim}		$0.00000
17	Current Period FAR_{Sec} = FAR x VAF_{Sec}		$0.00000
18	Prior Period FAR_{Sec}	+	$0.00000
19	Current Annual FAR_{Sec}		$0.00000
	VAF_{Prim} = 1.0455		
	VAF_{Sec} = 1.0775		

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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 January 25, 2017, the two corresponding twelve-month recovery periods and the filing dates are as shown below. Each filing shall include detailed work papers in electronic format to support the filing.

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

A recovery period consists of the billing 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, emission allowance costs 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 Southwest Power Pool (SPP) revenues and costs, revenue from the sale of Renewable Energy Certificates or Credits (REC), and emission allowance revenues collected during the accumulation period. Eligible costs do not include the purchased power demand costs associated with purchased 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.

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

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FORMULAS AND DEFINITIONS OF COMPONENTS

FPA = 95% * ((ANEC – B) * J) +T + I + P

95% = Customer responsibility for fuel variance from base level.

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

FC = Fuel Costs Incurred to Support Sales:

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

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

E = Net Emission Costs:

The following costs and revenues reflected in FERC Account Numbers 509, 411.8 and 411.9: emission allowance costs offset by revenues from the sale of emission allowances including any associated hedging costs, and broker commissions, fees, commodity based services, and margins.

PP = Purchased Power Costs:

The following costs or revenues reflected in FERC Account Number 555: purchased power costs, capacity charges for capacity purchases less than 12 months in duration, energy charges from capacity purchases of any duration, settlements, insurance recoveries, and subrogation recoveries for

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FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

purchased power expenses, virtual energy charges, generating unit price adjustments, load/export charges, energy position charges, ancillary services including penalty and distribution charges, hedging costs, broker commissions, fees, and margins, SPP EIS market charges, and SPP Integrated Market charges.

TC = Transmission Costs:
The following costs reflected in FERC Account Number 565 (excluding Base Plan Funding costs and costs associated with the Crossroads generating station): transmission costs that are necessary to receive purchased power to serve native load and transmission costs that are necessary to make off system sales.

OSSR = Revenues from Off-System Sales:
The following revenues or costs reflected in FERC Account Number 447: all revenues from off-system sales but excluding revenues from full and partial requirements sales to Missouri municipalities that are associated with GMO, hedging costs, SPP EIS market charges, and SPP Integrated Market revenues.

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

Hedging Costs = 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 purchased power costs, 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, and swaps.

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

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FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

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

L&P S_{AP} x Base Factor (BF)
MPS S_{AP} x Base Factor (BF)

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

J = Missouri Retail Energy Ratio = Retail kWh NSI/S_{AP}
Where: total system kWh equals retail and full and partial requirement NSI associated with GMO.

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 below.

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

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FORMULAS AND DEFINITIONS OF COMPONENTS (continued)
Where:

FPA = Fuel and Purchased Power Adjustment

S_{RP} = Forecasted recovery period 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

The FPA will be calculated separately for L&P and MPS, and by voltage level, and the resultant FAR will be applied to the bills of customers in the respective rate districts and voltage levels.

BASE FACTOR (BF)

Company base factor costs per kWh:
$0.02076 for L&P
$0.02278 for MPS

TRUE-UPS

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

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

PRUDENCE REVIEWS

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

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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 January 21, 2021, the two corresponding twelve-month recovery periods and the filing dates will be as shown below. Each filing shall include detailed work papers in electronic format to support the filing.

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

A recovery period consists of the months during which the FAR is applied to 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 contacts 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 $.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.

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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], applicable taxes, natural gas costs, alternative fuels (i.e. tires, bio-fuel), fuel quality adjustments, fuel hedging costs, fuel adjustments included in commodity and transportation costs, broker commissions 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, propane costs, 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;

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

Subaccount 501300: fuel additives and consumable costs for Air Quality Control Systems (“AQCS”) operations, such as ammonia, hydrated lime, lime, limestone, powder activated carbon, urea, sodium bicarbonate, trona, 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 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

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

(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.

TC = Transmission Costs and Revenues:

The following costs reflected in FERC Account Number 561:

Subaccount 561400: all RTO scheduling, system control, dispatching services, and NERC fees;

Subaccount 561800: all RTO reliability, planning and standards 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;

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

The following revenues 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

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.

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.,

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FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

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;

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

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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.

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

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FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

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

- 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
- 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.

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FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

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. Net 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:
$0.02262 for L&P
$0.02455 for MPS

J = Missouri Retail Energy Ratio = Retail kWh sales/total system kWh
Where: total system kWh equals retail and full and partial requirement sales associated with GMO.

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

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FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

Where:

FPA = Fuel and Purchased Power Adjustment

S_{RP} = Forecasted recovery period 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

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:			Month dd, yyyy	Month dd, yyyy
			MPS	L&P
1	Actual Net Energy Cost (ANEC) = (FC+E+PP+TC-OSSR-R)		$0	$0
2	Net Base Energy Cost (B)	-	$158,037,263	$50,162,218
	2.1 Base Factor (BF)		$0.02455	$0.02262
	2.2 Accumulation Period NSI (S_{AP})		6,438,072,000	2,217,696,000
3	(ANEC-B)		$0	$0
4	Jurisdictional Factor (J)	*	0%	0%
5	(ANEC-B)*J		$0	$0
6	Customer Responsibility	*	95%	95%
7	95% *((ANEC-B)*J)		$0	$0
8	True-Up Amount (T)	+	$0	$0
9	Interest (I)	+	$0	$0
10	Prudence Adjustment Amount (P)	+	$0	$0
11	Fuel and Purchased Power Adjustment (FPA)	=	$0	$0
12	Estimated Recovery Period Retail NSI (S_{RP})	÷	0	0
13	Current Period Fuel Adjustment Rate (FAR)	=	$0.00000	$0.00000
14	Current Period FAR_{Prim} = FAR x VAF_{Prim}		$0.00000	$0.00000
15	Prior Period FAR_{Prim}	+	$0.00000	$0.00000
16	Current Annual FAR_{Prim}		$0.00000	$0.00000
17	Current Period FAR_{Sec} = FAR x VAF_{Sec}		$0.00000	$0.00000
18	Prior Period FAR_{Sec}	+	$0.00000	$0.00000
19	Current Annual FAR_{Sec}		$0.00000	$0.00000
	MPS L&P			
	VAF_{Prim} = 1.046573 1.029197			
	VAF_{Sec} = 1.082254 1.050476			

SCHEDULES TMR-5 THROUGH TMR-6

THESE DOCUMENTS CONTAIN HIGHLY CONFIDENTIAL INFORMATION NOT AVAILABLE TO THE PUBLIC

Table B-04

MPS ENERGY LOSS MULTIPLIERS

SERVICE LEVEL	Total System kWh	Total System Multiplier	Secondary Service kWh	Secondary Service Cumulative Multiplier	Primary Service kWh	Primary Service Cumulative Multiplier	Substation Service kWh	Substation Service Cumulative Multiplier	Transmission Service kWh	Transmission Service Cumulative Multiplier
Secondary		1.034093								
Sales	5,169,442,854		5,169,442,854							
Losses + Diversion	176,243,371		176,243,371							
Input to Primary	5,345,686,226		5,345,686,226	1.034093						
Primary		1.022808	5,345,686,226							
Primary Sales	459,421,984				459,421,984					
Primary Losses	132,404,492		121,925,870		10,478,622					
Input to Substation	5,937,512,701		5,467,612,096	1.057679	469,900,606	1.022808				
Substations			5,467,612,096		469,900,606					
Substation Sales	392,406,491						392,406,491			
Substation Losses	41,798,505		36,104,412		3,102,906		2,591,187			
ut to Transmission	6,371,717,698		5,503,716,508	1.064663	473,003,512	1.029562	394,997,678	1.006603		
Transmission		1.016522	5,503,716,508		473,003,512		394,997,678			
Transmission Sales	22,442,016								22,442,016	
Losses	105,643,632		90,931,823		7,814,914		6,526,110		370,785	
System Input	6,499,803,346		5,594,648,331	1.082254	480,818,426	1.046573	401,523,788	1.023234	22,812,801	1.016522
Losses + Diversion	456,090,000		425,205,477		21,396,442		9,117,297		370,785	

Table B-05

SJLP ENERGY LOSS MULTIPLIERS

	Total System		Secondary Service		Primary Service		Substation Service		Transmission Service	
SERVICE LEVEL	kWh	Multiplier	kWh	Cumulative Multiplier	kWh	Cumulative Multiplier	kWh	Cumulative Multiplier	kWh	Cumulative Multiplier
Secondary		1.020675								
Sales	1,851,435,944		1,851,435,944							
Losses + Diversion	38,279,137		38,279,137							
Input to Primary	1,889,715,082		1,889,715,082	1.020675						
Primary		1.020115	1,889,715,082							
Primary Sales	147,131,728				147,131,728					
Primary Losses	40,970,303		38,010,811		2,959,492					
Input to Substation	2,077,817,113		1,927,725,893	1.041206	150,091,220	1.020115				
Substations		1.008904	1,927,725,893		150,091,220					
Substation Sales	80,099,832						80,099,832			
Substation Losses	19,213,185		17,163,661		1,336,349		713,175			
Input to Transmission	2,177,130,130		1,944,889,554	1.050476	151,427,569	1.029197	80,813,007	1.008904		
Transmission		1.013096	1,944,889,554		151,427,569		80,813,007			
Transmission Sales	70,218,894								70,218,894	
Losses	29,430,375		25,469,488		1,983,034		1,058,294		919,558	
System Input	2,276,779,398		1,970,359,041	1.064233	153,410,603	1.042675	81,871,302	1.022116	71,138,452	1.013096
Losses + Diversion	127,893,000		118,923,097		6,278,875		1,771,470		919,558	

GMO TOTAL (MPS+SJLP) ENERGY LOSS MULTIPLIERS										
	Total System		Secondary Service		Primary Service		Substation Service		Transmission Service	
SERVICE LEVEL	kWh	Multiplier	kWh	Cumulative Multiplier	kWh	Cumulative Multiplier	kWh	Cumulative Multiplier	kWh	Cumulative Multiplier
Secondary		1.030555								
Sales	7,020,878,799		7,020,878,799							
Losses + Diversion	214,522,509		214,522,509							
Input to Primary	7,235,401,307		7,235,401,307	1.030555						
Primary		1.022109	7,235,401,307							
Primary Sales	606,553,712				606,553,712					
Primary Losses	173,374,795		159,964,730		13,410,065					
Input to Substation	8,015,329,814		7,395,366,037	1.053339	619,963,777	1.022109				
Substations		1.007188	7,395,366,037		619,963,777					
Substation Sales	472,506,323						472,506,323			
Substation Losses	61,011,690		53,158,870		4,456,382		3,396,438			
Input to Transmission	8,548,847,827		7,448,524,908	1.060911	624,420,158	1.029456	475,902,761	1.007188		
Transmission		1.015631	7,448,524,908		624,420,158		475,902,761			
Transmission Sales	92,660,910								92,660,910	
Losses	135,074,007		116,426,672		9,760,209		7,438,758		1,448,367	
System Input	8,776,582,744		7,564,951,580	1.077494	634,180,368	1.045547	483,341,519	1.022931	94,109,277	1.015631
Losses + Diversion	583,983,001		544,072,781		27,626,656		10,835,196		1,448,367	

GMO TOTAL (MPS+SJLP) COINCIDENT DEMAND LOSS MULTIPLIERS										
	Total System		Secondary Service		Primary Service		Substation Service		Transmission Service	
SERVICE LEVEL	kW	Multiplier	kW	Cumulative Multiplier	kW	Cumulative Multiplier	kW	Cumulative Multiplier	kW	Cumulative Multiplier
Secondary		1.031568								
Sales	1,555,545		1,555,545							
Losses + Diversion	49,105		49,105							
Input to Primary	1,604,650		1,604,650	1.031568						
Primary		1.039174	1,604,650							
Primary Sales	91,834				91,834					
Primary Losses	66,458		62,861		3,597					
Input to Transmission	1,762,941		1,667,510	1.071978	95,431	1.039174				
Substations		1.005126	1,667,510		95,431					
Substation Sales	71,703						71,703			
Substation Losses	9,405		8,548		489		368			
Input to Transmission	1,772,346		1,676,058	1.077474	95,920	1.044501	72,071	1.005126		
Transmission		1.018908	1,676,058		95,920		72,071			
Transmission Sales	11,534								11,534	
Losses	33,729		31,690		1,814		1,363		218	
System Input	1,817,609		1,707,749	1.097846	97,734	1.064250	73,434	1.024131	11,752	1.018908
Losses + Diversion	158,697		152,204		5,900		1,730		218	

SCHEDULES TMR-9

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