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| Exhibit No.: | |
| Issue: | Fuel Adjustment Clause, Residential Energy Efficient Pilot Programs, Lake Road Allocation, Clean Charge Network and Energy Crossroads Center. |
| Witness: | Tim M. Rush |
| Type of Exhibit: | Direct Testimony |
| Sponsoring Party: | KCP&L Greater Missouri Operations Company |
| Case No.: | ER-2018-0146 |
| Date Testimony Prepared: | January 30, 2018 |

**MISSOURI PUBLIC SERVICE COMMISSION**

**CASE NO.: ER-2018-0146**

# DIRECT TESTIMONY

# OF

# TIM M. RUSH

**ON BEHALF OF**

**KCP&L GREATER MISSOURI OPERATIONS COMPANY**

**Kansas City, Missouri**
**January 2018**

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

**DIRECT TESTIMONY**

**OF**

**TIM M. RUSH**

**Case No. ER-2018-0146**

**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;

II. Address the proposed Residential Energy Efficiency Pilot Program and how they fit into the Company's MEEIA programs.

III. Address 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

IV. Address the Company’s proposed Electric Vehicle (EV) charging tariff.

V. Address and support the Company’s position regarding the Crossroads Energy Center and transmission expenses for Crossroads.

## 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, all with the intent to improve the FAC and its processes.

**Q: What are the rules for continuing an FAC?**

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

**Q: 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. While the Company has utilized the existing line loss study currently in rates, a new line loss study is currently in process which will provide updated information and reflect to consolidation of rates that occurred in our last rate case. It should be completed in February, 2018, and will be filed in this case well in advance of the case true-up or Staff’s and other parties direct or rebuttal 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, See Schedule TMR-1, part D for a description of changes proposed in the FAC. Two Riders designed to provide renewable energy for customers are discussed in the Direct Testimony of Kimberly Winslow and Bradley Lutz. One program is titled Solar Subscription Pilot Rider and the second titled Renewable Energy Rider. While these Riders will not offset the energy directly billed to the customer, the Renewable Energy Rider will require modification to the current FAC. The Company proposes to add language to the FAC tariff to carve the costs and revenues of the Renewable Energy Rider out of the costs and revenues in the FAC. The phrases to be added will be included in both revenue account 456.1 - "amounts associated with portions of Power Purchase Agreements dedicated to specific customers under the Renewable Energy Rider" and purchased power expense account 555 - "excluding (a) amounts associated with portions of Power Purchase Agreements dedicated to specific customers under the Renewable Energy Rider".

Additionally, the Company proposes some minor changes to add specific additives that have either been added or deleted from use at the plants.

**Q: Will the Renewable Energy Rider and the changes to the FAC cause any problems with the computation or administration of the FAC?**

A: No. Both the costs and revenues that will be taken out of the FAC are easily identified and will not cause any problems with the FAC.

**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, a portion of 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 contained in the FAC for GMO represent approximately 28% 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 fuel cost 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 and revenues 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.

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.

**Q: What protections exist for customers with regard to the FAC?**

A: Beyond the semi-annual reviews performed for each filing of the FAC changes, the FAC is also audited through a detailed prudence review by the Staff no less frequently than at eighteen (18)-month intervals. OPC participates in the review process. To date, no disallowances have occurred where the Company has been found to be imprudent in any aspects of the FAC.

## II. RESIDENTIAL ENERGY EFFICIENT PILOT PROGRAM

**Q: What is the Company requesting in this proceeding?**

A: The Company is proposing three new residential rate pilot programs as described in the testimony of Company witnesses Marisol Miller and Kimberly Winslow. The three rates are:

1.) Residential Time of Use Rate

2.) Residential Time of Use with Demand Rate

3.) Residential Demand Rate

**Q: Please describe how you propose to implement these new rate pilot programs?**

A: The three rates are being proposed as pilots and are limited to 1,000 residential customer participants for each rate. Residential customers may select to be on one of the three rates instead of the standard residential rate. Customers selecting one of these pilot program rates will need to have new AMI metering available at their residence. The three rate pilot programs are designed to allow the residential customer to take more control of their electric bill by modifying usage patterns or installing equipment that results in a lower energy bill. It will also likely result in savings to the Company and non-participating customers as well. For example, instead of running the clothes dryer during the peak period when energy costs are high, the customer could wait until later in the evening or early in the morning. By altering the time for certain tasks, a customer would be billed at a lower rate when the clothes dryer is in operation than if they had run the dryer during the peak period. Another example would be where the customer starts the dishwasher in the evening, rather than during the peak period.

The Company considers these rate pilot programs "Energy Efficiency" rates. By taking advantage of the different types of rates, customers energy consumption and demand will be affected. As a result, the Company considers these rate pilot programs to be MEEIA programs and proposes that they be included in its next MEEIA portfolio of programs.

**Q: If the Company considers these rate pilot programs MEEIA programs, then why are they included in this rate case?**

A: The primary reason is these three rate pilot programs affect revenues and are better addressed in a rate case that will then allow these three rate pilot programs to be reviewed as a rate design issue in this case while the revenues flow through the recovery mechanism in the Company's next MEEIA program portfolio.

**Q: Please explain how you anticipate these rates being implemented?**

A: The Company proposes that the rates be approved in this case, but not made effective until the next MEEIA program cycle, which should happen several months after the effective date of rates in this case. It is anticipated that MEEIA Cycle 3 will go into effect in April, 2019.

**Q: Why wait until the MEEIA Cycle 3 is approved before these rates are implemented?**

A: The primary reason is the uncertainty of approval of the pilot programs in the context of MEEIA 3 plan. Additionally, billing modifications are necessary to be able to properly bill these rates. Lastly, customer marketing and education is necessary to solicit customers for the different pilots.

**Q: You mentioned that it is anticipated that usage and demand will be modified and that customers will save money. Likewise, you anticipate that the Company will see some benefit from these usage changes. How do you anticipate handling the reduced revenues and the savings to the Company?**

A: First, it is expected that customers who select to go on the rates will likely save money initially, without any modification of the current usage or usage pattern. For example, customers whose usage pattern is such that they currently use a predominant amount of energy during the off-peak periods will likely save money without any change in their behavior. As a result, the Company requests that those savings be included in the program cost portion of the DSIM rate, beginning for Cycle 3.

Second, it is expected that customers will change usage patterns to take advantage of the rates. These savings will not be accounted for until they are measured. The Company proposes to account for these customer savings through an evaluation, measurement and verification (EM&V) process, consistent with the other MEEIA programs. These savings would be reflected in the net shared benefits portion of the DSIM rate.

Third, any earnings opportunity from these programs would be addressed in the Cycle 3 MEEIA filing.

**Q: Why isn't the Company offering these rate programs to all customers?**

A: The first reason is that we do not have enough information regarding customer behavior to determine if the programs will be successful. We intend to use the sample of customers to help better understand the behavioral changes that may result from the pilot programs. Second, we are just completing our new Customer Information System which has a number of new options to customers and will provide the Company substantial flexibility in the future. As a result, implementing a substantial pilot in the MEEIA program portfolio will give us greater flexibility for the future.

## III. LAKE ROAD ALLOCATION

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

A: Yes. As a result of the 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: Have you previously testified on this subject?**

A: Yes. In GMO's previous rate case, Case No. ER-2016-0156, the Company proposed a modification to the existing allocation methodology.

**Q: Was it accepted by the Commission in that proceeding?**

A: The overall case was ultimately settled and the Commission never had to make a decision on this subject. Staff witness Alan Bax addressed the issue and recommended a review of all allocations attributable to Lake Road steam and electric operations once more operational data was available in order to understand the allocation methodology.

**Q: Has the Company completed a review?**

A: Yes. The Company has performed a review and is recommending an allocation methodology. The Company has provided the allocation procedural manual attached to my testimony as Schedule TMR-5 which contains the allocation procedures the Company proposes to utilize.

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

A: Yes. The Lake Road plant provides GMO electric generation with multiple units which burn coal, natural gas and fuel oil. The Lake Road plant also serves five industrial steam customers that take steam service from the 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 and natural gas. Boilers 1 through 4 and 8 can burn either natural gas or fuel oil. The 900 lb. side also produces electricity from three electric turbines supported by the above mentioned boilers. The Lake Road plant also has an 1800 lb. system that consists of one boiler and one turbine. The 1800 lb. system's primary fuel was coal until June 2016, when it ceased burning coal due to environmental regulation compliance issues. It is capable of burning natural gas or fuel oil. The remainder of the plant is made up of three combustion turbines.

The discontinuance of burning coal on the 1800 lb. system has a significant impact on current plant allocations and is the primary reason for changing the method for allocating costs at the Lake Road plant between the industrial steam and electric jurisdictions. The current allocation method for allocating plant, operation and maintenance expenses relies heavily on a coal burn allocation between industrial steam and electric jurisdictions.

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

A: Yes. Outside factors in recent years have changed how the units at the Lake Road plant are dispatched for electricity. Some of those factors are the increased use of wind generation in the area, the abundance of natural gas along with lower gas prices and the

Southwest Power Pool's ("SPP") launch of the Integrated Marketplace on March 1st of 2014.

Current electric dispatching by the SPP of the 900 lb. side is typically for peak generation, ancillary services and spinning reserve. When the units are online they are typically 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 the SPP is dispatching the 900 lb. side, 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 the Lake Road plant, outside factors and changes in the SPP's dispatching, 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 monthly maximum steam sales demand and dividing the sum of the maximum steam sales demand 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 the Company is proposing.

**900 lb ELECTRIC/STEAM DEMAND ALLOCATION FACTOR**

1a. Determine the average of the maximum coincident peaks of the steam sales customers in mmBtu/Hr in a 36 month period. The average of these peaks is multiplied 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. 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 then 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. 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 a percentage. By taking 1 minus this percentage, the result is the electric allocation factor.

**Q: Has the Company made any changes to other plant, 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: Yes, All changes are reflected in the Allocation Procedural Manual attached to my Direct Testimony as Schedule TMR-5.

## IV. CLEAN CHARGE NETWORK

**Q: What is the Clean Charge Network ("CCN") program?**

A: KCP&L and GMO launched an initiative to install and operate more than 1,000 Electrical Vehicle Charging Stations ("EVCS") throughout their respective service territories. Company witness Chuck Caisley describes the CCN program in greater detail.

**Q: What is the Company seeking regarding the Clean Charge Network ("CCN")?**

A: The Company is requesting recovery in rate base of its electric vehicle charging stations ("EVCS") as well as approval of the tariff that will be used to charge end users of the EVCS. The Company believes that the EVCS meet the definition of "electric plant" under Missouri law and therefore must be regulated by the Commission when owned by a public utility.

**Q: Hasn't this issue already been decided by the Commission?**

A: Yes, in KCP&L's last rate case the Commission determined that EVCS are not "electric plant" and therefore it lacks statutory authority over the equipment. The Commission determined that the CCN was not a regulated service but should be operated as a competitive service and denied KCP&L's proposed tariff rate. KCP&L has appealed the Commission's Report and Order to the Missouri Court of Appeals and a decision will likely occur during the pendency of this rate case. The Company believes that the charging service it provides must be recognized as a regulated service under Missouri law.

The Commission also determined that KCP&L may include in rate base any equipment, such as distribution lines, transformers, and meters, necessary to provide electric service to an owner of an EV charging station, whether that owner is affiliated with KCP&L or not.

**Q.Why is KCP&L requesting recovery of the EVCS?**

A. The Company disagrees with the Commission's determination that EVCS are not electric plant and therefore does not have jurisdictional authority over EV charging stations. There is no basis for treating this investment different from other investments incurred to allow the Company to provide efficient service to its customers. All of KCP&L's customers, both EV users and non-EV users alike, will benefit from the CCN. Benefits include increased off-peak electricity usage, environmental benefits from reduced $CO_2$ emissions and lower ozone-reducing pollutants, economic impacts resulting in job creation, improved customer programs, and lower costs and efficiency by having the utility install, own and operate the EVCS. The increase in home-based usage to charge EVs will also provide a broader base over which to spread system costs. These facilities are part of the KCP&L system, as any other they are infrastructure. The investment is necessary to provide electric service to our mobile customers and should be recovered like other prudent infrastructure investments. Furthermore, data gathered since the conclusion of the last rate case shows that the CCN is achieving its intended goals of expanding the adoption of electric vehicles in the service territory relative to other markets without such a utility-led effort. Company Witness Chuck Caisley describes these activities, changing market conditions and developments on utility programs in other jurisdictions.

**Q: Are the costs for EVCS currently included in GMO's rates?**

A: No. These costs are not currently in rates. The costs to date have been treated below the line and borne by the Company's shareholders.

**Q: How has GMO treated its EVCS expenses and revenues?**

A: GMO has treated both revenues and expenses consistent with the Order in Case No. ER-2016-0285.

**Q: What is the approximate revenue requirement impact of the EVCS?**

A: GMO is asking for Commission approval to include the costs, both capital and O&M, of its EVCS in base rates as part of this case. Any off-setting tax credit would be a reduction to its revenue requirement. The Company is also asking for approval of a tariff, Schedule CCN, to allow for charging the electric vehicle (attached to my testimony as Schedule TMR-6). The capital cost for the project to be included in rates is net plant of $2.6 million. This amount would be offset by the revenues from the charging stations.

**Q: What has been the growth in kWh sales since the initial installations of the EVCS?**

A: The growth in kWh sales at the charging stations for GMO is significant. Sales in 2015 were 10,651 kWh. That grew to 58,356 in 2016 and 2017 kWh sales reached 176,897 kWh's. If you priced 2017 sales at $0.20 per kWh, it would provide revenues of $35,379. However, sales are expected to continue to grow as the market continues to develop. Growth at customers residence is not measured directly, but has materially grown over this same period as demonstrated by the growth in the number of electric vehicles discussed in the Direct Testimony of Chuck Caisley.

**Q: Will Commission approval of the CCN and related tariff provide GMO the opportunity to continue to add charging stations beyond those currently envisioned?**

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

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

A: Yes, I do.

**Q. What else did the Commission order with respect to the CCN?**

**A.** The Commission ordered KCP&L to accumulate data regarding the appropriate electric rate to charge owners of EVCS and provide that data during its next general rate case.[1]

**Q. Has the Company accumulated the data?**

A. Yes. The Company used ChargePoint to record and collect session level data for every charging session at the EVCS. The Company developed and analyzed a composite system level, 15-minute, load profile for all Level 2 and Level 3 (Fast DC) charging stations throughout the GMO and KCP&L service territories.

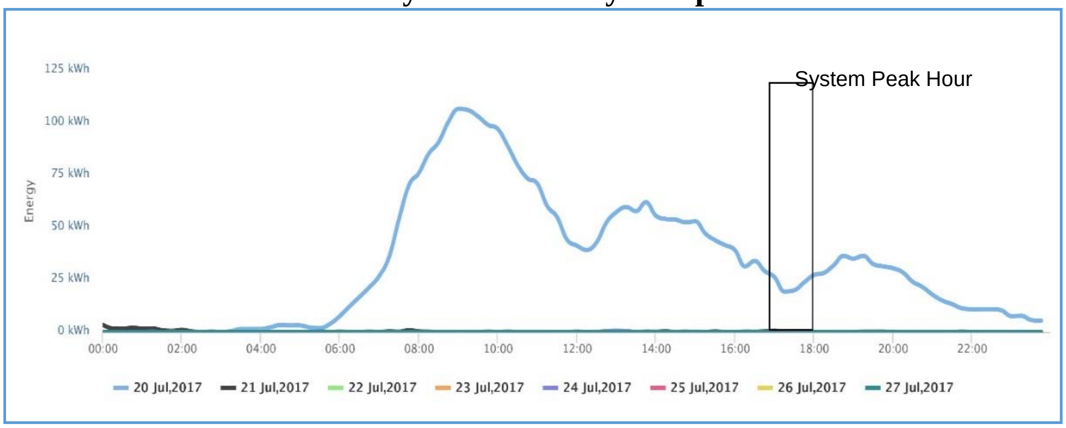
**Q. What did this analysis conclude?**

**A**. The following graphs illustrate each load profiles for the 2017 system peak day, July 22. For the month of July 2017, the Level 2 stations had a composite non-coincident

[1] Cite order ER-2016-0285 Report and Order 5-3-2017 page 46

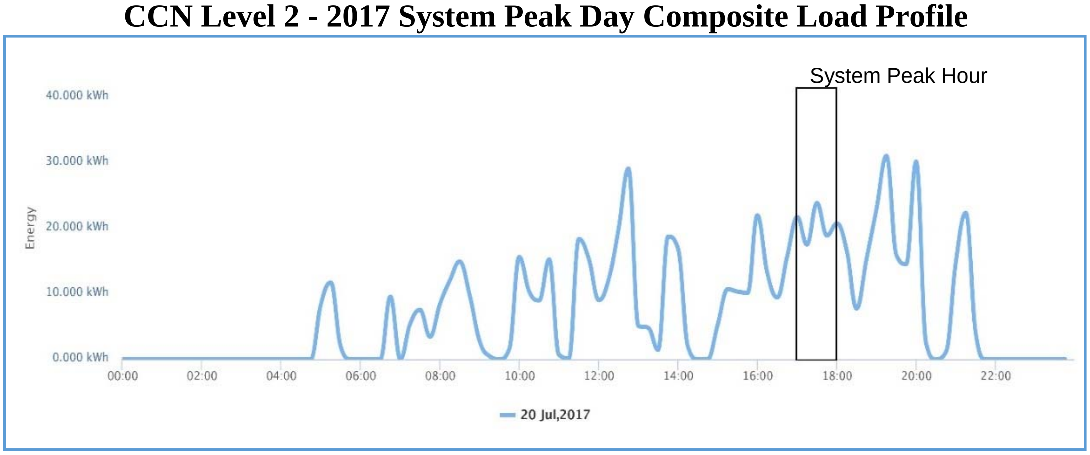
peak (NCP) of 512.4 kW with a monthly load factor 18.8%. As illustrated in the figure below, the composite Level 2 station demand had little coincidence with the system peak hour (5-6 p.m.), with an average of 89.7 kW (17.7% of the composite NCP) occurring during the system peak hour.

**CCN Level 2 - 2017 System Peak Day Composite Load Profile**




The Level 3, Fast DC, stations had a composite non-coincident peak (NCP) of 171.5 kW with a monthly load factor 13.6%. As illustrated in the figure below, the composite Level 3 station demand had significantly more coincidence with the system peak hour (5-6 p.m.), with an average of 81.9 kW (47.8% of the composite NCP) occurring during the system peak hour.

**CCN Level 2 - 2017 System Peak Day Composite Load Profile**



**Q. Based on this analysis, what can you conclude as the appropriate electric rate to charge owners of EV Charging Stations?**

**A.** In general, we see the Level 2 charging stations use occurring in the early daytime period when users either come to work or are doing daily activities. Level 3 charging stations have a more up and down load pattern during the day, but are more likely to have a load on the system at the peaking period.

Based on the data currently available, I believe the most appropriate electric rate to charge owners of EVCS for service to locations serving only EVCS is the Small General Service rate, Schedule SGS. The structure of this tariff is well suited for service to both Level 2 or Level 3 charging stations.

For commercial service with demands less than 25 kW, the SGS rate is comprised of a Service Charge and an Energy Charge. The 25 kW limit of the SGS rate will accommodate the majority, if not all, of the CCN Level 2 charging locations where the owner of the Station which is only serving electrical charging. The Company's analysis also shows that the CCN Level 2 stations have minimal impact on overall system peak capacity and therefor the SGS energy only rate is appropriate.

The SGS rate is also appropriate for Level 3 (Fast DC) charging stations which have demands greater than 25 kW. For service with demands greater than 25 kW, the SGS rate is comprised of a Service Charge, an Energy Charge, and a Facilities Charge for all kW in excess of 25 kW. As the Company's analysis shows, the CCN Level 3 charge station demands have a level of coincidence with the Company system peak, thereby justifying the additional demand charges.

Again, this addresses electrical service which is connected to an EVCS. If the EVCS is combined with other usages, such as a convenience stores, then the appropriate rate to charge would be dependent on the overall load characteristics of the location.

**Q: Is this consistent with the Company's current practice?**

A: Yes. As a result of the 0285 Order , the Company began charging the EVCS at each of its locations the SGS retail rate. The Company began charging electric vehicles $0.20 per kWh for Level 2 charging stations and $0.25 per kWh for Level 3 charging stations, where the host site no longer wished to pay for the service. For host sites that wished to continue paying for electric vehicle charging, the Company still charged the per kWh rate of $0.20 and $0.25, but accumulated this for the month and reflected it on the hosts bill.

The SGS revenues were collected from the Company and reflected in the regulated revenues of the Company. The sales revenues from vehicle charging at $0.20 and $0.25 per kWh were reflected "below the line" and were used to offset the EVCS costs consistent with what was not allowed in the KCP&L rate case.

**Q: Please describe what you are proposing to charge customers in this case?**

A: Schedule TMR-6 presents the proposed new tariff titled Public Electric Vehicle Charging Station Service, Schedule CCN. It is specific to GMO-owned charging stations available to EV drivers throughout its service territory. The proposed tariff does not address charging of EVs at customer single-family residences or at privately owned and operated charging stations like some businesses have provided at their sites specifically for their employees and guests.

**Q: How is the tariff designed?**

A: The Schedule CCN rate tariff establishes a flat rate per kWh for both Level 2 and Level 3 EVCS. The tariff does not specifically identify and separate out the current riders, such as the FAC, DSIM or RESRAM rate riders at the price "at the pump". However, those amounts would be included in the rate and backed out of the revenues to appropriately include them in the Company's reporting in its books and records. The rate is intended to recover investment and expenses in the EVCS. This includes a flat rate of $0.20 per kWh for Level 2 EVCS and a flat rate of $0.25 for Level 3, Fast DC EVCS. Taxes and fees would be applied separately.

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

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

A: Yes. The flat rate incorporates a driver contribution to defray a portion of the costs for the EVCS. As more and more electric vehicles utilize the services, the contribution would be increased.

**Q: How did GMO determine the kWh rates set forth in Schedule CCN?**

A: First, the Company wanted to have a price that was consistent throughout the GMO and KCP&L service territories. Second, the rate should be simple to understand. Therefore, we propose not to specifically identify the various riders on the price at the charging station. Thirdly, we wanted the price to be reflective of our SGS rates as best as possible.

And lastly, to recover the cost of service as more users begin to utilize the service. The rates proposed are flat kWh rates that are intended recover the investment in the facilities overtime as additional vehicles utilize the service, The Company is also proposing to include an optional Session Overstay Fee in the tariff.

**Q:** **Can you explain the concept of the Session Overstay Fee contained in the proposed tariff?**

A: Under the proposed tariff, the Company has the discretion to impose a Session Overstay Fee to incent customers to move their vehicles once the charging process is completed so that other customers can have access to charging station. With the Session Overstay Fee, the driver would be provided a grace period after the EV has completed charging before the Session Overstay Fee would be imposed. The grace period allows the EV driver to receive notification (via text or e-mail) and move their vehicle to avoid these charges.

**Q** **How does the Company intend to determine if a Session Overstay Fee should be applied?**

A: The Company plans to only implement the Session Overstay Fee when needed at charging station locations based on the occupancy and availability of charging ports at each host site location. Initially, the Company does not plan to implement the Session Overstay Fee on any of the charging stations. The Company will monitor charge port availability and overstay times and implement Session Overstay Fee at host locations where the additional inducement is needed to get drivers to move their vehicle.

**Q.** **Will the Session Overstay Fee be the same at all Clean Charge Network locations?**

A. No. Schedule CCN sets a cap of $6.00 per hour for Session Overstay Charge and care must be taken to ensure they are set high enough to incent drivers to move their vehicle but not so high as to discourage customers from using the stations. The Company set the maximum of the range of Session Overstay Charge at $6.00 per hour based on the maximum rate of charge provided by the Level 3 charging station – the fastest charger. The lost revenue potential of a Level 2 charge port is significantly less (approximately $1/hr.) and the Session Overstay Charge should reflect this differential. The Company wants to establish the minimum number of Session Overstay Charges levels but recognizes that higher overstay charges may be needed at some locations compared to other.

**Q. What type of other notification can a driver receive?**

A: Notifications are available to make drivers aware of their EV charging status at all times. Text and email notifications can be set up to notify drivers when their car is fully charged, when charging is interrupted, when a Session Overstay grace period is ending, and when charging stations become available for use.

**Q: Has GMO begun an analysis on EV home charging and possible rate designs that may be beneficial?**

**A.** The majority of EV charging is at the home. With GMO's late system peak occurring in the late afternoon, at home charging could have substantial system peak coincidence. Typically, EV charging in the home would occur when the vehicle owner arrives, which could add extra load to the peak periods of the Company.

**Q. Has GMO evaluated TOU rates for home charging?**

A. Yes. As described in the Direct Testimony of Marisol Miller, GMO contracted with Burns & McDonnell (B&McD) to perform a Residential Rate Design Strategy Study, in order to prepare a general long term plan for implementing Residential rate designs that align with the utility's internal goals and objectives, reflect good rate making principles, and align with future technologies being implemented. One of the outcomes of the study was the design of a residential TOU rate that can be used by and marketed to EV owners to shift EV load off-peak in a cost-efficient manner in all. This study is discussed further in her testimony and the report from B&McD. The TOU rate proposed in this proceeding can easily be used to incentivize EV drivers to charge their vehicles during off-peak periods during the late night hours.

## V. CROSSROADS ENERGY CENTER

**Q: What is the Crossroads Energy Center?**

A: Crossroads Energy Center is a 300 MW GMO natural gas-fired peaking facility that is part of GMO's regulated supply portfolio located in Clarksdale, Mississippi and consists of four gas-fired 75 MW combustion turbines. The facility was constructed in 2002 and added to the GMO supply portfolio in 2008.

Crossroads generates electricity from natural gas that is supplied by pipelines that are geographically remote from the resources that supply gas to GMO's other gas-fired generators and provides capacity equivalent to 15% of GMO's 2017 peak load. Transmission service is currently provided by MISO and SPP. Prior to Entergy joining MISO, transmission service was provided by Entergy and SPP.

When GMO capacity needs were evaluated in 2007, Crossroads was found to be the lowest cost option for GMO customers, even when the cost of transmission was considered.

**Q: Why was Crossroads added to the GMO regulated portfolio?**

A: In 2007 when the decision to add this asset to GMO's supply portfolio was evaluated, it was the lowest cost supply option for GMO customers. The Company concluded that this was the appropriate asset to add the generating asset to its portfolio. GMO also entered into a 20-year transmission agreement with Entergy in 2009 to move the power from Crossroads to GMO's service territory in Missouri. The transmission is required in order to claim Crossroads in meeting its generation and reserve requirements. The overall cost of the facility and transmission expense still met the lowest cost supply option for GMO customers.

**Q: In 2007 when the capacity needs of GMO were evaluated and Crossroads was identified as the lowest cost option, what was the assumption on transmission costs?**

A: In the 2007 evaluation, the Company included $12 million per year in transmission costs for the Crossroads option.

**Q: Is Crossroads and the transmission expense in getting power to the GMO territory included as part of GMO's regulated rate base in Missouri?**

A: Yes and no. Even though presented with evidence that this plant and transmission costs were the lowest cost option at the time it was added to the GMO generation fleet, a significant portion of the plant was disallowed by the Commission in the 2010 rate case, Case No. ER-2010-0356. Additionally, the Commission disallowed the entire amount of Crossroads transmission expense. As a result, GMO does not recover FERC-approved transmission rates associated with Crossroads.

**Q: What was the value of the transmission disallowance in the 2012 rate case?**

A: At the time of the decision in 2012 in Case No. ER-2012-0156, the Commission disallowed transmission costs of over $4.9 million per year. This was the cost of transmission on the Entergy system.

**Q: Please provide some background of what has transpired since the Commission's rate order that in Case No. ER-2012-0175 regarding Crossroads?**

A: In December 2013 Entergy, with whom GMO entered into a 20-year agreement for transmission service for Crossroads in 2009, joined the regional transmission organization ("RTO") known as MISO. As a result, transmission costs necessary to move Crossroads power to GMO's service territory immediately increased to approximately $12 million per year and those costs have since grown to approximately $13 million per year.

**Q: Was Entergy's decision to join MISO in 2013 expected?**

A: No. In fact, prevailing thought at the time GMO entered into the transmission agreement in 2009 was that Entergy would join Southwest Power Pool ("SPP"), in which case the transmission cost paid by GMO to move Crossroads power to GMO's market area would have fallen to $0 per year. Entergy's move to MISO occurred subsequent to the MPSC disallowance of Crossroads transmission service related costs. Even with this increase in transmission expense, Crossroads remains the low cost option for GMO customers even if the Commission would have allowed the full cost of the plant and the transmission expenses in rates.

**Q: This issue has been going on since 2008, when the decision was made to include Crossroads as part of the regulated operations and to enter into a 20-year agreement with Entergy to purchase transmission service. What are you asking this Commission to do in this case?**

A: The Company is not asking the Commission to reverse any of its prior decisions. GMO proposes to continue the disallowance levels adopted by the Commission in Case Nos. ER-2010-0356 and ER-2012-0175 with respect to rate base and transmission costs. GMO proposes to include in rates the incremental increase in transmission cost above $4.9 million, which was the amount disallowed in Case ER-2012-0175. The transmission cost dollar amounts are detailed in the Direct Testimony of GMO witness Ronald Klote.

**Q: Why is this proposal reasonable?**

A: Crossroads is an incredibly good asset for GMO's customers. It was the least cost option in GMO's 2007 IRP, and even with Entergy-related transmission costs it remains the least cost option. Crossroads thus provides low-cost capacity equal to 15% of GMO's 2015 peak demand in addition to operational benefits resulting from its location outside of GMO's service territory. For example, during the polar vortex of January-February 2014, gas was available at Crossroads when it was unavailable for gas-fired generation located near GMO's market area.

In light of the value Crossroads provides to GMO customers and GMO's acceptance of the rate base and transmission cost disallowance levels determined by the Commission in Case Nos. ER-2010-0356 and ER-2012-0175, I believe it is reasonable to include the incremental transmission costs above $4.9 million in GMO customer rates.

**Q: What has been the impact on both customers and the Company since Crossroads was included in GMO operations?**

A: While Crossroads costs about $132 million, the Commission disallowed nearly $70 million of gross plant from the actual costs. As a result, GMO customer have had the capacity of the Crossroads facility at a bargain price and had reflected in rates since 2008, approximately $40 million to pay for the facility. On the other hand, GMO shareholders have lost $70 million in plant disallowance and the entire transmission expenses since 2008. As a result, GMO shareholders will have lost over $100 million from recovery in rates in both plant disallowances and transmission expense disallowances. To put this into an annual perspective, GMO customers will pay about $5 million annually for the right to have 300 MW of an incredibly reliable and efficient peaking unit, while GMO shareholders will lose about $17 million annually.

If the Commission accepts the position of the Company in this case, this will result in the Company losing about $10 million annually and customers paying about the same $12 million in rates on an annual basis.

**Q: Is the recovery of transmission costs related to an out-of-state generating facility unprecedented in Missouri?**

A: No. Like GMO, The Empire District Electric Company has a generating asset (Plum Point) located in Arkansas within the MISO region. Also like GMO, Empire is in SPP so Empire must pay MISO for transmission service for their generation within MISO. Empire pays the same exact MISO rate for transmission service as GMO pays to MISO. However, unlike GMO, Empire has been allowed recovery of these transmission service costs in its Missouri rates.

**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-2018-0146 |

**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 twenty-eight (28) 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 29th day of January 2018.

Anthony R Westenkirchner

Notary Public

My commission expires: 4/26/2021

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

## Requirements to Continue or Modify the Fuel Adjustment Clause

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

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

See Schedule TMR-2.

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

No change is proposed.

**(C) Proposed RAM rate schedules:**

See Schedule TMR-3.

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

The design and intended operation of the Fuel Adjustment Clause (FAC) is the same as approved in Case No. ER-2016-0156. The changes proposed in this filing are for the amounts contained in base rates as well as the addition of new additives that the Company is now using, and the addition of wording related to the Renewable Energy Rider tariff. Some key features of the FAC include:

- The FAC factor is based upon historical differences between the cost of fuel, energy and certain transmission costs net of off-system sales revenue built into base rates and the actual net costs of these items as incurred during the two six-month accumulation periods.

- There is 95% recovery of the difference between these actual net 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 and revenue amortizations, transportation costs, and certain transmission costs. These costs are offset by off system sales revenues, and the revenues from the sale of renewable energy credits. Carrying costs are calculated monthly at the Company's short term debt rate.

- The under or over recovery will be accumulated for 6 months. The collection period for the accumulation is 12 months.

- The base amount in the current tariff is $0.02055

- The proposed base amount for GMO FAC base rate is $0.02465 per kWh.

**(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. 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. Emission Allowance costs and amortizations are in FERC account 509.

> Please see the proposed tariff sheets included in Schedule TMR-3 for the complete listing of all costs that need to be considered for recovery under the propose continuation of the RAM along with the specific accounts that will be used for each cost item on the Company's utility books and records.

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

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

The Federal Energy Regulatory Commission (FERC) Code of Federal Regulations is the basis for the Company's accounting codes. Sales for resale are recorded in FERC account 447. Revenues from the sale of emission allowances and renewable energy credits are recorded in FERC account 509 as an offset to expense.

> Please see the proposed tariff sheets included in Schedule TMR-3 for the complete listing of all revenue accounts that need to be considered in the determination of the amount eligible for recovery under the propose continuation of the RAM along with the specific accounts that will be used for each revenue item on the Company's utility books and records.

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, ER-2012-0175, and ER-2016-0156.

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

See the Direct Testimony of Jessica L. Tucker in this case for a discussion of the FAC and mitigation of market risk/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.

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

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

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

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

As required, the FAC allocates cost by voltage level using commission approved allocation methods.

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

See Direct Testimony of Robert B. Hevert.

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

The definitions of the costs and revenues included in the FAC have been updated in the actual proposed tariffs and therefore, sections (H) and (I) now reference those tariff sheets. Changes made to the tariff sheets are as follows:

> 127.14: 501000 - Removed "alternative fuels (i.e. tires, bio-fuel)" (the Company no longer has the air burn permits for these fuels); Added ", broker commissions and fees (fees charged by an agent, or agent's company to facilitate transactions between buyers and sellers)," (to be consistent with KCP&L); 501300 - Added "limestone inventory adjustments" (to be consistent with wording in 501000); Added calcium bromide to the description (AQCS additive used by the Company); Removed trona (no longer used); Added propane (used with Urea to make Urea work);
>
> 127.15: 547000 - Added "broker commissions and fees (fees charged by an agent, or agent's company to facilitate transactions between buyers and sellers)," (for consistency with KCP&L); 547300 - Added "and consumable costs for Air Quality Control Systems ("AQCS") operations, such as ammonia or other consumables which perform similar functions." (to be consistent with 501300); 509000 - Re-ordered section 509 to be costs, offset by revenues; 555000 - Added "broker commissions and fees (fees charged by an agent, or agent's company to facilitate transactions between buyers and sellers)," (to be consistent with KCP&L); Added wording to exclude purchased power agreements dedicated to specific customers under the Renewable Energy Rider tariff (new service, the cost of which, should be excluded from the

FAC); Removed subaccounts 555021 and 555031 (no longer needed with a combined GMO)

127.16: 565000 - Updated SPP transmission percentage allowed in the FAC (new FERC Form 1 information available); Added wording relating to customers participating in the Renewable Energy Rider tariff (new service, the cost of which, should be excluded from the FAC); 447020 - Added wording relating to customers participating in the Renewable Energy Rider tariff (new service the cost of which should be excluded from the FAC)

127.21: B Factor - Updated base rate factor based upon current rate case levels.

127.21-127.23 Added expansion factors for transmission and substation levels (agreed to in previous case)

(J) was changed to include the settlement information from case number ER-2016-0156. In (L) the discussion of hedging has been removed and the discussion of annual internal and external audits has been added.

**(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:**

GMO has a long-term resource planning process. The electric utility resource plan produced by the process is also known as an integrated resource plan or IRP. An objective of this planning process is to identify the least cost alternatives and select a preferred resource plan that maintains adequate capacity reserves for reliability. GMO prepared and filed its latest triennial IRP report in April 2015. Updates to that IRP report were filed March 15, 2016, and June 1, 2017. Under the current IRP rule, the next triennial IRP is to be filed April 1, 2018.

**(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 Jessica L. Tucker 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-2016-0156.

**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 CLAUSE
(Applicable to Service Provided February 22, 2017 through Effective Date of This Tariff)

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 December 21, 2020, 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, 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 $0.00001, and aggregated 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 CLAUSE
(Applicable to Service Provided February 22, 2017 through Effective Date of This Tariff)

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 adjustments included in commodity and transportation costs, 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 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 and 501420: 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, and settlement proceeds, insurance recoveries, subrogation recoveries for fuel expenses,

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 broker commissions and fees (fees charged by an agent, or agent's company to facilitate transactions between buyers and sellers).

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, charges and credits related to the SPP Integrated Marketplace ("IM").

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

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:

The following costs reflected in FERC Account Number 565:

Subaccount 565000: non-SPP transmission used to serve off-system sales or to make purchases for load, excluding any transmission costs associated with the Crossroads Power Plant and 39.62% of the SPP transmission service costs which includes the schedules listed below as well as any adjustments to the charges in the schedules below:

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

Subaccount 565020: the allocation of the allowed costs in the 565000 account attributed to native load;

Subaccount 565027: the allocation of the allowed costs in the 565000 account attributed to transmission demand charges;

Subaccount 565030: the allocation of the allowed costs in account 565000 attributed to off-system sales.

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

OSSR = Revenues from Off-System Sales:
The following revenues or costs reflected in FERC Account Number 447:
Subaccount 447020: all revenues from off-system sales. This includes charges and credits related to the SPP IM. 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 447020 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.

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

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

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;

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

FORMULAS AND DEFINITIONS OF COMPONENTS (Continued)

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 January 1 or July 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
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.

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, at the generation level.

BF = Company base factor costs per kWh: $0.02055

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 accumulation period 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 adjustment amount, if any.

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 generation level..

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 recovery period, 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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FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE
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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 December 29, 2022, 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, all as incurred during the accumulation period. These costs will be offset by jurisdictional off-system sales revenues, applicable SPP revenues, and revenue from the sale of Renewable Energy Certificates or Credits ("REC"). Eligible costs do not include the purchased power demand costs associated with purchased power contracts in excess of one year. Likewise revenues do not include demand or capacity receipts associated with power contracts in excess of one year.

APPLICABILITY

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

The FAR is the result of dividing the FPA by forecasted Missouri retail net system input ("$S_{RP}$") for the recovery period, expanded for Voltage Adjustment Factors ("VAF"), rounded to the nearest $0.00001, and aggregated 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, natural gas reservation charges, fuel quality adjustments, 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), 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 fuel expenses in the 501 Accounts.
Subaccount 501020: the allocation of the allowed costs in the 501000, 501300, and 501400 accounts attributed to native load;
Subaccount 501030: the allocation of the allowed costs in the 501000, 501300, and 501400 accounts attributed to off-system sales;
Subaccount 501300: fuel additives and consumable costs for Air Quality Control Systems ("AQCS") operations, such as ammonia, hydrated lime, lime, limestone, limestone inventory adjustment, powder activated carbon, urea, propane, sodium bicarbonate, calcium bromide, sulfur, and RESPond, or other consumables which perform similar functions;
Subaccount 501400 and 501420: residual costs and revenues associated with combustion byproducts, slag and ash disposal costs and revenues including contractors, materials and other miscellaneous expenses.

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FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

The following costs reflected in FERC Account Number 547:
Subaccount 547000: natural gas, and oil costs for commodity, transportation, broker commissions and fees (fees charged by an agent, or agent's company to facilitate transactions between buyers and sellers), storage, taxes, fees and fuel losses, and settlement proceeds, insurance recoveries, subrogation recoveries for fuel expenses,

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 and consumable costs for Air Quality Control Systems (“AQCS”) operations, such as ammonia or other consumables which perform similar functions.

E = Net Emission Costs:
The following costs and revenues reflected in FERC Account Number 509:
Subaccount 509000: NOx and $SO_2$ emission allowance costs, including any associated broker commissions and fees (fees charged by an agent, or agent's company to facilitate transactions between buyers and sellers) offset by revenue amortizations and revenues from the sale of NOx and $SO_2$ emission allowances.

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, insurance recoveries, and subrogation recoveries for purchased power expenses, broker commissions and fees (fees charged by an agent, or agent's company to facilitate transactions between buyers and sellers), and charges and credits related to the SPP Integrated Marketplace (“IM”) or other IMs, excluding amounts associated with portions of purchased power agreements dedicated to specific customers under the Renewable Energy Rider Tariff.

Subaccount 555030: the allocation of the allowed costs in the 555000 account attributed to purchases for off-system sales;

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FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

TC = Transmission Costs:
The following costs reflected in FERC Account Number 565:
Subaccount 565000: non-SPP transmission used to serve off-system sales or to make purchases for load, excluding any transmission costs associated with the Crossroads Power Plant and 50.50% of the SPP transmission service costs which includes the schedules listed below as well as any adjustments to the charges in the schedules below:

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

excluding amounts associated with portions of purchased power agreements dedicated to specific customers under the Renewable Energy Rider tariff.

Subaccount 565020: the allocation of the allowed costs in the 565000 account attributed to native load;

Subaccount 565027: the allocation of the allowed costs in the 565000 account attributed to transmission demand charges;

Subaccount 565030: the allocation of the allowed costs in account 565000 attributed to off-system sales.

OSSR = Revenues from Off-System Sales:
The following revenues or costs reflected in FERC Account Number 447:
Subaccount 447020: all revenues from off-system sales. This includes charges and credits related to the SPP IM, excluding (a) amounts associated with portions of purchased power agreements dedicated to specific customers under the Renewable Energy Rider tariff, and (b) amounts associated with generation assets dedicated, as of the date BF was determined, to specific customers under the Renewable Energy Rider tariff. 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;

Subaccount 447030: the allocation of the includable sales in account 447020 not attributed to retail sales.

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FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

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.

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

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

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

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

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

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

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FORMULAS AND DEFINITIONS OF COMPONENTS (Continued)

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 January 1 or July 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
- 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, at the generation level.

BF = Company base factor costs per kWh: $0.02465

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 accumulation period 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 adjustment amount, if any.

FAR = $FPA/S_{RP}$

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

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
Annual Substation Voltage $FAR_{Sub}$ = Aggregation of the two Single Accumulation Period Substation Voltage FARs still to be recovered
Annual Transmission Voltage $FAR_{Trans}$ = Aggregation of the two Single Accumulation Period Transmission Voltage FARs still to be recovered

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

Where:

FPA = Fuel and Purchased Power Adjustment

$S_{RP}$ = Forecasted recovery period retail NSI in kWh, at the generation level.

VAF = Expansion factor by voltage level
$VAF_{Sec}$ = Expansion factor for lower than primary voltage customers
$VAF_{Prim}$ = Expansion factor for primary to substation voltage customers
$VAF_{Sub}$ = Expansion factor for substation to transmission voltage customers
$VAF_{Trans}$ = Expansion factor for transmission voltage customers

TRUE-UPS

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

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

PRUDENCE REVIEWS

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

FUEL ADJUSTMENT CLAUSE – Rider FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE
(Applicable to Service Provided Effective date of This Tariff Sheet and Thereafter)

| Accumulation Period Ending: | | | |
|---|---|---|---|
| | | | **GMO** |
| 1 | Actual Net Energy Cost (ANEC) = (FC+E+PP+TC-OSSR-R) | | $0 |
| 2 | Net Base Energy Cost (B) | - | $0 |
| | 2.1 Base Factor (BF) | | $0.02465 |
| | 2.2 Accumulation Period NSI ($S_{AP}$) | | 0 |
| 3 | (ANEC-B) | | $0 |
| 4 | Jurisdictional Factor (J) | x | 0% |
| 5 | (ANEC-B)*J | | $0 |
| 6 | Customer Responsibility | x | 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 $FAR_{Sec}$ = FAR x $VAF_{Sec}$ | | $0.00000 |
| 15 | Prior Period $FAR_{Sec}$ | + | $0.00000 |
| 16 | Current Annual $FAR_{Sec}$ | = | $0.00000 |
| | | | |
| 17 | Current Period $FAR_{Prim}$ = FAR x $VAF_{Prim}$ | | $0.00000 |
| 18 | Prior Period $FAR_{Prim}$ | + | $0.00000 |
| 19 | Current Annual $FAR_{Prim}$ | = | $0.00000 |
| | | | |
| 20 | Current Period $FAR_{Sub}$ = FAR x $VAF_{Sub}$ | | $0.00000 |
| 21 | Prior Period $FAR_{Sub}$ | + | $0.00000 |
| 22 | Current Annual $FAR_{Sub}$ | = | $0.00000 |
| | | | |
| 23 | Current Period $FAR_{Trans}$ = FAR x $VAF_{Trans}$ | | $0.00000 |
| 24 | Prior Period $FAR_{Trans}$ | + | $0.00000 |
| 25 | Current Annual $FAR_{Trans}$ | = | $0.00000 |
| | | | |
| 26 | $VAF_{Sec}$ = 1.0709 | | |
| 27 | $VAF_{Prim}$ = 1.0419 | | |
| 28 | $VAF_{Sub}$ = 1.0419 | | |
| 29 | $VAF_{Trans}$ = 1.0419 | | |

# SCHEDULE TMR-4

# THIS DOCUMENT CONTAINS CONFIDENTIAL INFORMATION NOT AVAILABLE TO THE PUBLIC ORIGINAL FILED UNDER SEAL

# KCP&L GREATER MISSOURI OPERATIONS ELECTRIC/STEAM ALLOCATION PROCEDURES CASE NO. ER-2018-0146

August 1994
Revised October 1994
Revised December 1994
Revised January 2018

## Contents

# I. CAPITAL PLANT ALLOCATION – Lake Road

## A. Lake Road Capital Plant Assigned 100% to Electric

The following Lake Road capital plant is to be allocated 100% to Electric, with the noted exceptions:

- Lake Road Unit 1 through 4 turbines (Account 310-316). Does not include the Boilers which are allocated or steam specific utility accounts ending in xxx09 listed in subsection B below.
- All combustion turbine generators and associated equipment (Account 342-346).
- Turbine building and other buildings and structures housing and/or associated with the 100% electric generation facilities (Account 311 & 341). Does not include steam specific utility accounts ending in xxx09 listed in subsection B below.

## B. Lake Road Capital Plant 100% Assigned to Industrial Steam

The following Lake Road Capital plant is to be allocated 100% to Industrial Steam:

- All steam specific plant utility accounts ending in xxx09 such as 31009, 31109, 31209, 31509, 37509, 37609, 37909, 38009 and 38109

## C. Lake Road Capital Plant Common to Electric and Industrial Steam

The following Lake Road capital plant is to be allocated between Electric and Industrial Steam, using the allocation methods specified and applied to any balance to be allocated after allocations in subsections A and B above.

1. All Boilers and Turbines in account 312, 314 and 316

**Allocation** – Property remaining to be allocated for account 312, 314 and 316 will be allocated first by applying the 900lb Steam Demand Allocation Factor as described below. Then each individual plant account, 312, 314 or 316, will be allocated based on the ratio derived from the total allocated to steam or electric over the sum total plant cost of each individual plant account 312, 314 or 316.

The 900lb Steam Demand Allocation Factor is determined using the average maximum hourly coincident peak for steam for each month over a 36 month period divided by the maximum capability of turbines 1-3 and the average maximum hourly coincident peak for steam. (See attached Schedule TMR-5, Wkpr 1).

2. Structures, Accessory Equipment, Software and General Plant (Account 303, 311, 315 and 391 through 398).

**Allocation -** Allocate based on the ratio derived from the total plant allocated to industrial steam and electric as calculated in subsections A, B and C above for Accounts 312, 314, 316 and 341 through 346 combined.

D. Reserve for Depreciation Allocation – Lake Road

The following Lake Road reserve for depreciation will be allocated between Electric and Industrial Steam, using the allocation methods specified:

1. Structures, Accessary Equipment, Software and General Plant (Account 303, 311, 315 and 391 through 398). Does not include steam specific utility accounts ending in xxx09.

**Allocation -** Allocate based on the ratio derived from the total plant cost allocated to industrial steam and electric as calculated in subsections A, B and C above for Accounts 312, 314, 316, 341 through 346 combined.

2. Boiler Plant (Account 312). Does not include steam specific utility accounts ending in xxx09.

**Allocation** – Allocate based on the ratio derived from the total plant cost allocated to industrial steam and electric for 312 Accounts only. See subsection C (1) Allocation above.

3. Turbogenerator Plant (Account 314)

**Allocation** – Allocate based on the ratio derived from the total plant cost allocated to industrial steam and electric for 314 Accounts only. See subsection C (1) Allocation above.

4. Miscellaneous Plant Equipment (Account 316)

**Allocation** – Allocate based on the ratio derived from the total plant cost allocated to industrial steam and electric for 316 Accounts only. See subsection C (1) Allocation above.

5. Combustion turbine generators and associated structures and equipment (Accounts 341-346)

**Allocation** – Allocate 100% to Electric

6. Steam specific plant utility accounts ending in xxx09 such as 31009, 31109, 31209, 31509, 37509, 37609, 37909, 38009 and 38109.

**Allocation** – Allocate 100% to Industrial Steam

## II. INVENTORY – Fuel - Lake Road

The fuel inventory will be allocated based on the minimum fuel inventory levels required for each operation, recognizing the fact that the LR electrical load is not predictable and a larger fuel inventory is required to sustain system reliability during extended periods of abnormally high electrical generation at LR. The Coal fuel inventory quantities above and beyond the minimum coal inventory levels will be allocated based on a 50/50 split between electric and steam. This split is premised on the need to maintain a 60 day average burn on coal inventory, while electric load is totally unpredictable. (See attached Schedule TMR-5, Wkpr 3 for fuel inventory analysis dated 11/1/2017)

Oil inventory is primarily a reserve fuel for both electric and steam load. Oil for electric generation covers each generating unit at the Lake Road Plant. As such, the allocation of oil should be based on the overall Plant Allocation Factor, which looks at electric capability of the entire plant and steam load. (See attached Schedule TMR-5, Wkpr 3 for fuel inventory analysis dated 11/1/2017). The plant allocation factor is calculated consistent with the 900lb steam demand allocation factor, but considers all turbines and boilers capable of burning oil. (See attached Schedule TMR-5, Wkpr 1 for the Fuel Oil Demand Factor calculation).

## III. INVENTORY – Materials and Supplies - Lake Road

Materials and Supplies Inventory for Lake Road are allocated 100% to Electric.

## IV. OTHER RATE BASE ITEMS – Lake Road

### A. Prepayments

Prepayments for Lake Road are allocated 100% to Electric.

### B. Regulatory Assets and Liabilities

Regulatory Assets and Liabilities will be allocated on the unique circumstance of each asset or liability.

1. Missouri DSM Programs, Iatan 1 and Common, and Iatan 2 are allocated 100% to Electric.
2. ERISA Steam Tracker is allocated 100% to Steam.
3. FAS87 Pension Tracker and OPEB Tracker are allocated based on Electric After Steam Allocation (A&G) factor. The A&G factor is based on a 50/50 weighting between the Allocated Plant Base factor and Allocated O&M factor described below in Section V11.

### C. Deferred Taxes

Deferred taxes for Lake Road will be allocated based the Allocated Plant Base Factor. This factor is the Ratio of Total GMO Plant per the most current Form 1 filed excluding Asset Retirement plant accounts 317, 347 and 399. The adjusted Total will be reduced by the total Steam Allocated plant amount allocated in Section 1, subsections A, B and C above.

### D. Customer Advances and Deposits

Customer Advances and Deposits for Lake Road will be allocated 100% to Electric.

## V. EXPENSE – FUEL

### A. Fuel and Daily Ash Expense Allocations

The procedure outlined in the January 1995, paper entitled "Exergy-Based Electric and Steam Allocation Procedure for Lake Road 900# Plant Fuel and Auxiliary Power" (hereinafter referred to as the "Exergy Approach") should be used for the basis of allocations. (See Attached Report Page 8-11 below).

Daily ash removal expenses will be allocated as described on the attached report dated April 14, 1994 on Page 12-13 below.

### B. Auxiliary Electric Power Allocation

The method of determining the amount of auxiliary electric power to be allocated to industrial steam and to electric users will be that method presented in the January 1995, paper on the "Exergy Approach" (See attached Report Page 11 below). The auxiliary electric power will be priced using the average system energy cost ($/MWH) for each month, which includes all Lake Road Plant and Iatan generation costs, fuel handing expenses, and all purchased power expenses. Additionally, the Company's average purchased capacity cost ($/MW) will be used to price the demand. An average monthly demand of 2 MW will be used. Billing considerations and accounting for the auxiliary electric power charges will be treated through "steam transfer credits", rather than direct billings.

## VI. EXPENSES – Non-Fuel O&M Expense Allocation

Operation and Maintenance (O&M) expenses refer to expenses associated with the production, transmission and distribution functions. O&M expenses are classified in FERC accounts 500-514 and 546-598. The allocation of O&M Expense Accounts are listed in Schedule TMR-5, Wkpr 2.

Non-Fuel O&M Accounts 500-514, the allocation is primarily based on the ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M for the most recent full calendar year referred to as the "Electric After Steam Allocation (O&M) factor. The allocated Steam Payroll is derived by multiplying the total non-fuel production Lake Road Payroll charged to O&M for the most recent full calendar year by the Equivalent Employment Factor.

The Equivalent Employment Factor is the fraction of time spent by a typical Lake Road Plant operating crew on the operation of the industrial steam system, based upon a breakdown of each operator's time. See Schedule TMR-5, Wkpr 4.

## VII. EXPENSES – A&G Expense Allocation

Administrative and General (A&G) expenses refer to expenses associated with administrative and general functions of the company, as contrasted with expenses directly associated with the production and transmission and distribution functions. A&G expenses include salaries and wages, outside services, injuries and damages, employee benefits, regulatory commission expenses, advertising, rents and maintenance. A&G expenses are classified in FERC accounts 901 through 935. The allocation of A&G Expense Accounts are listed in Schedule TMR-5, Wkpr 2.

Not all charges to A&G FERC accounts are allocable. Costs incurred which benefit only a particular utility operation are directly charged to that operation. Also, Customer Accounts, Customer Service and Sales Expense are allocated 100% to Electric.

However, the majority of A&G expenses accounts 920-935 are allocated between electric and industrial steam operations based on the Electric After Steam Allocation (A&G) Factor which is two allocation factors that are given 50/50 weighting described below:

1. Allocated Plant Base Factor - Ratio of Total GMO Plant per the most current Form 1 filed excluding Asset Retirement plant accounts 317, 347 and 399. The adjusted Total is reduced by the total Steam Allocated plant amount allocated in Section 1, subsections A, B and C above.
2. Allocated O&M Factor - The most current Annual Surveillance filed is updated for the "Electric After Steam Allocation (O&M) factor" described in Section V1 above.

There should be reasonable correlation between the factor(s) used and the A&G costs incurred. The two factors selected include that correlation as A&G expenses primarily represent costs incurred in <u>managing</u> the Company's personnel and operating and maintenance activities and <u>controlling</u> the Company's investment in plant.

## VIII. EXPENSES – Property Taxes

Property Tax Expense is allocated based on the Allocated Plant Base Factor - Ratio of Total GMO Plant per the most current Form 1 filed excluding Asset Retirement plant accounts 317, 347 and 399. The adjusted Total is reduced by the total Steam Allocated plant amount allocated in Section 1, subsection A, B and C above.

**Exergy-Based Electric and Steam Allocation Procedure for Lake Road 900# Plant Fuel and Auxiliary Power**

**January 1995**

The Lake Road 900# Plant fuel allocation is performed between steam electric constituencies based upon the amount of fuel energy required to supply each on a daily basis. To determine this allocation, the fuel energy is tracked on an exergy[1] basis through the 900# plant. The fuel "cost" per unit of exergy of flow streams within the plant are determined by the "cost" of input streams and second law efficiencies of plant equipment. The use of this method is strongly supported in technical literature dealing with the allocation of costs in cogeneration facilities.[2]

Fuel energy is based upon the "higher heating value" of the fuels and is considered to be 100% available to the boilers. That is, the exergy content and heating value of the fuels are assumed to be equal. One mmBtu[3] of fuel is defined as one cost unit. By tracking the exergy flow and it's "cost" through the plant, the quantity of fuel energy required to supply a given flow stream is simply the exergy flow of the stream multiplied by the unit cost of that stream. Exergy is measured relative to the reference state of water at 14.3 psia (corresponding to the plant evaluation of 812 feet above sea level) and the plant well water temperature, typically 60° F.

The procedure begins with the total daily fuel, steam, water, and electricity flows to, from and within the 900# plant, along with the average thermodynamic conditions. Using heat and mass balance equations, an approximate daily 900# plant heat balance is determined. The major components in the heat balance are: 900# boilers (1-5, 7), 900# turbines and condensers (1-3), industrial steam system (high pressure and low pressure), pressure reducing valves, attemperating equipment, flash tanks, water treatment plant, general plant (pumps, feedwater heaters, 900# auxiliary steam loads), and Unit 4/6 (auxiliary steam). The daily total mass and exergy flows in and out of the above components are determined. After these quantities are known, a set of simultaneous equations is solved to determine the cost of the various flow streams. These equations are determined by equating the total costs in and cost of the individual components. That is the following equation is solved for each component.

$$\sum(E_i\, c_i) = \sum(E_e\, c_e) \qquad (1)$$

The above equation states that the sum of the products of incoming exergy flows ($E_i$) and their respective unit costs ($c_i$) is equal to the sum of the products of the exiting exergy flows ($E_e$) and their respective unit costs ($c_e$). Generally, the equation (1) has the following form.

$$\sum (M_i\, E_i\, c_i) = \sum (M_e\, E_e\, c_e) + W_e\, c_e$$

In equation (2), the M's represents flow in pounds per day, $E$'s represent exergy content of the fluid in Btu per pound, the W represents work generated by the device in Btu/day (i.e. turbine shaft work to a generator) and the c's represent the unit cost in Btu's of fuel per Btu of exergy.

As an example, consider a boiler consuming 100 mmBtu of fuel per hour at a cost of 1 (fuel Btu per exergy Btu), with a feedwater flow and exergy content of 100,000 lb/hr and 75 Btu/lb at a cost of 5, and

[1] See "Definition of Exergy" on page 10.

[2] See Reference List on page 10.

[3] mmBtu = one million British thermal units = $10^6$ Btu.

delivering 100,000 lb/hr of steam with an exergy content of 600 Btu/lb. The cost of the steam would be determined from the following equation.

$$\left[100(10^6)\frac{\text{Btu}}{\text{hr}} \times 1 \frac{\text{fuel Btu}}{\text{exergy Btu}}\right] \text{fuel} +$$

$$\left[100(10^3)\ \frac{\text{lb}}{\text{hr}} \times 75\ \frac{\text{Btu}}{\text{lb}} \times 5\ \frac{\text{fuel Btu}}{\text{exergy Btu}}\right] \text{feedwater} \qquad (3)$$

$$= 100\ (10^3)\frac{\text{lb}}{\text{hr}} \times 600\ \frac{\text{Btu}}{\text{lb}} \times c_{stm}$$

Solving for $c_{stm}$, the steam cost is 2.29 fuel Btu per exergy Btu. The total cost of the steam is 137 mmBtu of fuel per hour (100,000 lb/hr x 600 Btu/lb x 2.29 Btu fuel/Btu exergy).

In the case of multiple outputs from a plant component, it is necessary to establish one or more auxiliary equations which relate to the costs of the exergy flows. Usually, this consists of simply equating the exiting costs ($c_{e1} = c_{e2} = c_{e3}$ ...). That is, the output streams all share the incoming costs in proportion to their exergy contents. This approach is used for Lake Road Turbine 1: the cost per unit of exergy of the extraction steam is set equal to the cost of the shaft work developed in the high pressure turbine section (shaft work is considered 100% available to the generator).

In some cases it is necessary to apply different costs to the output flows. This is true with a low pressure turbine and condenser combination. The two outputs are the shaft work to the generator and the condensate returning to the plant. If these two outputs were assigned the same cost, the condensate would become quite expensive as it would be charged with much of the exergy destruction and rejection in the condenser and cooling tower. However, these losses were incurred so that electric generation could take place, not for production of condensate. Therefore, the cost of the condensate should not reflect these losses. Generally in this situation the condensate "by-product" is priced at zero or is assigned a cost per unit of exergy equal to that of the steam to the turbine. This shifts the cost of losses to the electric generation function, where it belongs. In the Lake Road Plant, fuel allocation calculations, condensate is priced at the same cost per unit of exergy as the incoming steam.

Another special case in costing exergy flows at Lake Road is due to Boiler 7. Boiler 7 is a heat recovery steam generator (HRSG) that supplies steam to the 900 psi header using the exhaust of Turbine 5, a 60 megawatt combustion turbine, as its heat source. The fuel burned in Turbine 5 is charged totally to the electric system. Therefore, the Turbine 5 exhaust and the Boiler 7 steam exergy that it generates "belong" to the electric system. To handle this situation, Boiler 7 steam exergy is assigned a cost of zero and is computationally provided only to Turbines 1 and 2 (Turbine 3 uses lower pressure steam). This mathematically reduces the amount of exergy provided to these turbines from Boilers 1 – 5 and consequentially the amount of Boiler 1-5 fuel charged to electric. This approach properly assigns to the electric system the full benefit of all fuel burned in Turbine 5. Further, this approach is consistent with the 100% electric allocation of Boiler 7 capital, operating, and maintenance expenses.

Exergy flows which are consumed in the general plant for the benefit of both steam and electric (e.g. 900# auxiliary steam) are assigned a cost of zero. This effectively "raises the price" of those exergy flows which are ultimately delivered to the steam or electric consumers and forces all fuel costs to be charged to these consumers in proportion to the exergy used by them.

Fuel Energy Charged to Electric

The daily fuel energy charged to electric is the total cost (mmBtu of fuel) or the turbine shaft work which drives the 900# plant generators plus the total cost of steam and condensates transferred to Unit 4/6.

Fuel Energy Charged to Industrial Steam

The daily fuel energy charged to industrial steam is the total cost (mmBtu of fuel) delivered to the industrial steam system. This includes the steam supplied through the 12" and 12" header meters, the attemperating water supplied to the customer steam lines, and the steam delivered to the high pressure steam customer plus the cost of exergy losses between plant and the high pressure customer meter.

The daily steam fuel allocation factor, $X_s$, is determined by dividing the mmBtu's of fuel charged to industrial steam from the above procedure by the total 900# boiler fuel mmBtu's consumed. This factor is used in the allocation of auxiliary power, described later.

## FUEL ALLOCATION PROCEDURE REFERENCE LIST


Gaggioli, R. A., and El-Sayed, Y. M., "A Critial Review of Second Law Costing Methods" present at the Forth International Symposium of on Second Law Analysis of Thermal Systems; Rome, Italy; May 25 – 29, 1987

Gaggioli, R. A., "Proper Evaluation and Pricing of 'Energy'"

Gaggioli, R. A., El-Sayed, Y. M., El-Nahsar, A.M., Kamaluddin, B., "Second Law Efficiency and Costing Analysis of a Combined Power and Desalination Plant"; Journal of Energy Resources Technology, Vol. 110, pp 114-118, June 1988.

Lang, Fred D., Horn, Ken F., "Make Fuel-Consumption Index Basis of Performance Monitoring"' Power, Vol. 134, No.10, pp 19-22, October 1990.

Moran, M. J., Availability Analysis, pp 206-210, ASME Press, 1989

Reistad, G. M., and Gangglioli, R. A., "Available-Energy Costing", October 30, 1979.

Sandage, P. E., "Turbine By-pass System Evaluation & Costing", Sega, Inc., October 18, 1990.

"Exergy Costing in Multi-Product Plants"


## DEFINITION OF EXERGY

Exergy is the thermodynamic quantity representing the maximum work than can be extracted from a given system or flow in an ideal, reversible process. It is calculated as $\mathbf{E = H - H_0 - T_0(S\text{-}S_0)}$ (neglecting kinetic and potential energy terms), in which H represents total enthalpy, S represents total entropy, and T represents absolute temperature. The subscript "0" indicates the property is at a reference states representative of ambient conditions or a "zero-energy level". Total exergy is measured in Btu and is often called "availability" or "available energy." (note that these terms are easily confused with other plant performance and thermodynamic quantities; "exergy" is more specific.) The term "exergy" often refers to specific exergy, which is the amount of exergy per unit of mass in a system or flow. Specific Exergy has units of Btu/lb and is calculated as $\mathbf{E = h - h_0 - T_0(s - s_0)}$ in which total enthalpy and entropy values are replaced with the corresponding specific enthalpy (h) and entropy (s). In practice, total exergy, E, of a fluid stream is usually calculated as the total mass flow, M, times specific exergy, or $\mathbf{E = Me}$.

AUXILIARY POWER ALLOCATION

The allocation of auxiliary power is performed in the following manner. First, the auxiliary power can be attributed directly to industrial steam or electric is subtracted from the total 900 psi plant metered auxiliary power, leaving an allocable quantity. Auxiliary power which is metered elsewhere in the plant, but benefits the 900 psi plant is added to the allocable amount. This result is then allocated by the fuel allocation factor (x, see the fuel allocation procedure). Auxiliary power which is directly attributed to each demand is then added to the allocated quantities.

Included in the auxiliary power attributed directly to each constituency is a daily base power consumption. The base usage for the total 900 psi plant is approximately 7.5 MWhr per day. This corresponds to an idle but ready plant (no industrial steam sales and no electric generation). The 7.5 MWhr is allocated between steam and electric using the Steam Demand Allocation Factor, which is defined in Appendix II of the Plant and O&M Allocation Procedure.

The process is summarized in the following steps.

1. Meter the daily auxiliary power (kwhr) used by the 900 psi plant via house service transformers #1 and #2, and #3 standby transformer, call this $P_{900}$.
2. Determine the 900 psi auxiliary power which is 100% electric (e.g. condensate and circulating water pump motors, cooling tower fans, substation power, and base station power for electric), call this $P_{el}$. These auxiliaries are estimated from hourly motor current readings, test data, and the allocation of the total base station power.
3. Determine the 900 psi auxiliary power which is chargeable directly to the industrial steam system, $P_{sI}$. The quantity is the sum of the base station power for team and the power consumed by various pumps for the benefit of industrial steam. The pump power consumption is that required for well water pumps, softener booster pumps, treated water make-up pumps, and attemperating water pumps. The total pumping energy quantities are calculated from water flows, pressures, and appropriate test data. Pumping energy for the water treatment function is allocated 96% to the industrial steam, based on the 1994 plant water use study for the MPSC Case EO-94-36.
4. Determine the portion of $P_{900}$ which can be allocated, $P'_{900} = P_{900} - P_{el} - P_{sI}$
5. Determine the auxiliary power consumed by Boiler 5 precipitator (supplied from the Unit 5 auxiliary transformer), $P_{5p}$ = K1 x number hours Boiler 5 is on burning coal, where K1 is the average kilowatt load drawn by the Boiler 5 precipitator.
6. Estimate the power consumed by #3 and #8 coal belts to deliver coal to the Boiler 5 coal bunkers, $P_{38}$ = K2 x number of tons of coal delivered to Boiler 5 bunkers. K2 is the average kwh required to transport one ton of coal from the reclaim pit to the Boiler 5 bunkers.
7. Meter the daily auxiliary power used by the rotary dumper, #6 and #7 coal belts, and related equipment supplied by #7 auxiliary transformer. Determine the amount allocated to steam by multiplying by the Plant Coal Burn Allocation Factor. Designate this power as **PSC**.
8. Total auxiliary power charged to steam is calculated as $P_S = X_S(P'_{900} + P_{5p} + P_{38}) + P_{sI} + P_{SC}$ where $X_s$ is the fuel allocation factor for steam.
9. Total auxiliary power charged to electric is the difference between the total plant auxiliary power and $P_S$.

ST. JOSEPH LIGHT & POWER COMPANY
CALCULATION OF ALLOCATION FACTORS FOR
LAKE ROAD DAILY ASH REMOVAL EXPENSES
Acct. 141-2501-119

Report 4/14/94

Expenses to be allocated with these factors include the removal cost of all ash material sent to the ash tank; it does not include cost associated with cleaning of material sluiced to the ash ponds, or removal of materials temporarily stored at the west coal yard area.

It is assumed that the amount of removal cost incurred is directly proportional to the amount of ash material sent to the ash tank, on a moisture-free, carbon-free basis. This material includes all coal ash from Boiler 5.

The total amount of ash material produced in Boilers 5 is directly proportional to the amount of coal burned. This allows a steam/electric allocation factor for ash to be calculated using coal burn (mmBtu) data currently available in the Lake Road Monthly Results Summary. The factors are based on a three-year rolling average; this is consistent with other factors used in our allocation procedures.

The calculations are as follows:

AAFS = ASH ALLOCATION FACTOR FOR STEAM
AAFE = ASH ALLOCATION FACTOR FOR ELECTRIC

$$AAFS = \frac{\text{Total Coal mmBtu to Steam}}{\text{Boiler 5 Coal mmBtu}}$$

$$AAFE = 1 - AAFS$$

3-Year Coal Burn (mmBtu) Data from Results Summary

| Year | Boiler 5 Coal Burn (mmBtu)* | Coal Btu To Steam (mmBtu)* |
|---|---|---|
| 2015 | 1,373,065 | 1,353,435 |
| 2016 | 1,853,331 | 1,805,706 |
| 2017 | 1,750,216 | 1,737,075 |
| TOTAL | 4,976,612 | 4,896,216 |

AAFS = 4,896,216 / 4,976,612 = 0.0983

AAFE = 1 – AAFS = 0.017

Material Cleaned from Coal Yard Runoff Ditches

The Coal Yard at Lake Road Plant has a ditch system surrounding it to collect rain-water runoff material and to prevent it from encroaching on neighboring property. The layout of the ditch system directs all flow to the south side of the coal yard where it is eventually pumped into the ash ponds. Through the course of a year, a considerable amount of material settles out in the ditches and must be cleaned out. Also, part of the runoff material settles out in the ash ponds and must be cleaned out, similar to other pond inputs.

The total annual weight (including moisture, unburned carbon, dirt, and some coal) of this material which is cleaned out and placed in the West Coal Yard area is estimated to be approximately 300 tons. This value is based on weigh-ticket results from trucks hauling an observed amount of material cleaned from the ditches.

Since the activity associated with accumulating this material is related to the coal pile itself, it should be allocated in accordance with the Plant Coal Burn Allocation Factor.

Boiler 5 Coal Mill Reject Material

A small amount of material is rejected from coal mills during the grinding process, and placed into a special chamber in the mill for periodic emptying. At Lake road, operators empty these chambers on the coal mills for Boiler 5 and haul the material by wheelbarrow to a collecting point outside the plant between 5 & 6 Boilers.

Every 3-4 weeks, coal handlers load this material on a dump truck and haul it to the West Coal Yard area where it is mixed with other temporarily stored material. Typically, they fill a dump truck during each of these cleanings. Based on this, the total annual weight of this material placed in the West Coal Yard area is estimated to be approximately 150 tons.

This material should be allocated according to the ratio of steam Btu's to total Btu's on Boiler 5.

# KCP&L Greater Missouri Operations
## Electric / Steam Allocation Factors
## L&P - Combined
## 12 Months Ended December 2016

| | | 2016 Electric | 2016 Steam | | Notes |
|---|---|---|---|---|---|
| **Electric/Steam Allocation Factors** | | | | | |
| 1 | Electric - 100% | 100.0000 % | 0.0000 % | 100.000 % | |
| 2 | Steam - 100% | 0.0000 % | 100.0000 % | 100.000 % | |
| 4 | Land Factor | 82.5407 % | 17.4593 % | 100.000 % | **Tab A, Factor D** |
| 5 | Structures Factor | 82.5407 % | 17.4593 % | 100.000 % | **Tab A, Factor D** |
| 6 | Boiler Plant Factor | 74.5543 % | 25.4457 % | 100.000 % | **Tab A, Factor A** |
| 7 | Turbogenerators Factor | 97.9069 % | 2.0931 % | 100.000 % | **Tab A, Factor B** |
| 8 | Access Elec Eqpt Factor | 82.5407 % | 17.4593 % | 100.000 % | **Tab A, Factor D** |
| 9 | Misc Steam Gen Eqpt Factor | 67.3379 % | 32.6621 % | 100.000 % | **Tab B, Factor A** |
| 10 | Electric/Steam Plant Factor | 82.5407 % | 17.4593 % | 100.000 % | **Tab A, Factor D** |
| **Income Statement Allocation Factors (Elec/Steam)** | | | | | |
| 13 | Electric After Steam Alloc (O&M) | 93.1605 % | 6.8395 % | 100.000% | **Tab D, Factor A** |
| 14 | Electric After Steam Alloc (A&G) | 98.9907 % | 1.0093 % | 100.000% | **Tab C, Factor A** |
| **Factors Used to Calculate Other Factors** | | | | | |
| 3 | Allocated Plant Base Factor | 99.1377 % | 0.8623 % | 100.000 % | **Tab C, Factor B** |
| 11 | 900 lb Steam Demand Factor | 67.3379 % | 32.6621 % | 100.000 % | **Tab B, Factor A** |

KCP&L Greater Missouri Operations

## STEAM PLANT ALLOCATION FACTOR
### Lake Road & IND Steam Plant-in-Service

| Plant Account | Total Lake Road Electric Plant | IND Steam Steam Plant | Total Steam Plant In-Service | Less: LR Unit 1-4 100% Electric | Equals: Remaining Allocable Elec Plt | 900# Steam Demand Factor Electric 67.3379% | 900# Steam Demand Factor Steam 32.6621% |
|---|---|---|---|---|---|---|---|
| **GENERATION - Allocated based on 900# Steam Demand Factor** | | | | See below | | | |
| 31200 - Boiler Plant Equipment | 84,998,345 | - | 84,998,345 | 22,814,469 | 62,183,877 | 41,873,309 | 20,310,567 |
| 31202 - Boiler Pollution Equipment | 5,639,497 | - | 5,639,497 | 1,178,849 | 4,459,647 | 3,003,032 | 1,456,615 |
| 31209 - Indus Stm-Boiler Plnt Eqp | | 1,738,366 | 1,738,366 | - | - | - | - |
| 31400 - Turbogen Units | 21,583,861 | - | 21,583,861 | 20,200,676 | 1,383,185 | 931,408 | 451,777 |
| 31600 - Miscellaneous Plant Equipment | 1,348,499 | - | 1,348,499 | 21,443 | 1,327,055 | 893,611 | 433,444 |
| 34100 - Other Struct & Improvements | 1,623,429 | - | 1,623,429 | 1,623,429 | 0 | 0 | 0 |
| 34200 - Fuel Holders & Accessories | 620,559 | - | 620,559 | 620,559 | - | - | - |
| 34300 - Prime Movers | 17,004,988 | - | 17,004,988 | 17,004,988 | - | - | - |
| 34400 - Generators | 2,688,016 | - | 2,688,016 | 2,688,016 | - | - | - |
| 34500 - Accessory Elec Equipment | 2,456,159 | - | 2,456,159 | 2,456,159 | - | - | - |
| 34600 - Misc Power Plant Equipment | - | - | - | - | - | - | - |
| | 137,962,354 | 1,738,366 | 139,700,720 | 68,606,589 | 69,353,765 | 46,701,360 | 22,652,404 |
| **GENERATION - Allocated based on Total Avg Alloc Calc Above** | Electric Plant | Steam Plant | Total Plant-in-Serv | Less: 100% Electric | Equals: Remaining Allocable Elec Plt | Allocation Based on Plant Ratios Above: Electric 82.5407% | Steam 17.4593% |
| 3100X - Land & Land Rights | 38,919 | 11,450 | 50,370 | 38,919 | - | - | - |
| 3110X - Struct & Improvements | 21,313,248 | 30,158 | 21,343,406 | 5,118,371 | 16,194,877 | 13,367,364 | 2,827,512 |
| 3150X - Accessory Electric Equipment | 11,522,782 | 48,849 | 11,571,630 | 5,807,648 | 5,715,134 | 4,717,311 | 997,822 |
| | 32,874,949 | 90,457 | 32,965,406 | 10,964,939 | 21,910,010 | 18,084,675 | 3,825,335 |
| **GENERAL PLANT** | Electric Plant | Steam Plant | Total Plant-in-Serv | Allocation Based on Plant Ratios Above: Electric 82.541% | Steam 17.459% | | |
| 30302 - Misc Intangible Software - 5 year | 350,000 | - | 350,000 | 288,892 | 61,108 | | |
| 39100 - Office Furniture and Equipment | 361,273 | - | 361,273 | 298,197 | 63,076 | | |
| 39102 - Computer Hardware | 116,827 | - | 116,827 | 96,430 | 20,397 | | |
| 39104 - Computer Software | 81,387 | - | 81,387 | 67,177 | 14,210 | | |
| 3920X - Transportation | 341,946 | - | 341,946 | 282,244 | 59,701 | | |
| 39300 - Stores Equipment | 13,425 | - | 13,425 | 11,081 | 2,344 | | |
| 39400 - Tools | 287,089 | - | 287,089 | 236,966 | 50,124 | | |
| 39500 - Lab Equipment | 438,654 | - | 438,654 | 362,068 | 76,586 | | |
| 39600 - Power Oper Equipment | 959,564 | - | 959,564 | 792,031 | 167,533 | | |
| 39700 - Communication Equipment | 621,398 | - | 621,398 | 512,906 | 108,492 | | |
| 39800 - Miscellaneous Equipment | 8,447 | - | 8,447 | 6,972 | 1,475 | | |
| | 3,580,009 | - | 3,580,009 | 2,954,965 | 625,045 | | |
| **INDUSTRIAL STEAM** | | | | | | | |
| 37509 - Ind Stm Dist Struct and Improvemts | | 132,825 | 132,825 | 100% Steam | | | |
| 37609 - Ind Stm Dist Mains | | 1,420,926 | 1,420,926 | 100% Steam | | | |
| 37909 - Ind Stm City Gate Meas and Reg | | 480,205 | 480,205 | 100% Steam | | | |
| 38009 - Ind Stm Services | | 100,842 | 100,842 | 100% Steam | | | |
| 38109 - Ind Stm Meters | | 363,850 | 363,850 | 100% Steam | | | |
| | - | 2,498,648 | 2,498,648 | | | | |
| **Total Plant Before Allocations:** | 174,417,312 | 4,327,471 | 178,744,784 | | | | |
| **Percentage Breakdown:** | 97.6% | 2.4% | 100.0% | | | | |

Tab B

| Plant Account | TOTAL PLANT AFTER ALLOCATIONS: Electric | Steam | Total |
|---|---|---|---|
| 31200 - Boiler Plant Equipment | 64,687,778 | 20,310,567 | 84,998,345 |
| 31202 - Boiler Pollution Equipment | 4,181,882 | 1,456,615 | 5,638,497 |
| 31209 - Indus Stm-Boiler Plnt Eqp | - | 1,738,366 | 1,738,366 |
| 31400 - Turbogen Units | 21,132,083 | 451,777 | 21,583,861 |
| 31600 - Miscellaneous Plant Equipment | 915,054 | 433,444 | 1,348,499 |
| 34100 - Other Struct & Improvements | 1,623,429 | 0 | 1,623,429 |
| 34200 - Fuel Holders & Accessories | 620,559 | - | 620,559 |
| 34300 - Prime Movers | 17,004,988 | - | 17,004,988 |
| 34400 - Generators | 2,688,016 | - | 2,688,016 |
| 34500 - Accessory Elec Equipment | 2,456,159 | - | 2,456,159 |
| 34600 - Misc Power Plant Equipment | - | - | - |
| | 115,309,950 | 24,390,771 | 139,700,720 |
| Post-Allocation Plant Ratios | 82.5407% | 17.4593% | 100.0% |
| 3100X - Land & Land Rights | 38,919 | 11,450 | 50,370 |
| 3110X - Struct & Improvements | 18,485,735 | 2,857,671 | 21,343,406 |
| 3150X - Accessory Electric Equipment | 10,524,959 | 1,046,671 | 11,571,630 |
| | 29,049,614 | 3,915,792 | 32,965,406 |
| 30302 - Misc Intangible Software - 5 year | 288,892 | 61,108 | 350,000 |
| 39100 - Office Furniture and Equipment | 298,197 | 63,076 | 361,273 |
| 39102 - Computer Hardware | 96,430 | 20,397 | 116,827 |
| 39104 - Computer Software | 67,177 | 14,210 | 81,387 |
| 3920X - Transportation | 282,244 | 59,701 | 341,946 |
| 39300 - Stores Equipment | 11,081 | 2,344 | 13,425 |
| 39400 - Tools | 236,966 | 50,124 | 287,089 |
| 39500 - Lab Equipment | 362,068 | 76,586 | 438,654 |
| 3960X - Power Oper Equipment | 792,031 | 167,533 | 959,564 |
| 39700 - Communication Equipment | 512,906 | 108,492 | 621,398 |
| 39800 - Miscellaneous Equipment | 6,972 | 1,475 | 8,447 |
| | 2,954,965 | 625,045 | 3,580,009 |
| 37509 - Ind Stm Dist Struct and Improvemts | - | 132,825 | 132,825 |
| 37609 - Ind Stm Dist Mains | - | 1,420,926 | 1,420,926 |
| 37909 - Ind Stm City Gate Meas and Reg | - | 480,205 | 480,205 |
| 38009 - Ind Stm Services | - | 100,842 | 100,842 |
| 38109 - Ind Stm Meters | - | 363,850 | 363,850 |
| | - | 2,498,648 | 2,498,648 |
| **Total Plant After Allocations:** | 147,314,528 | 31,430,255 | 178,744,784 |
| | | (to rate factor worksheet) | |
| **Percentage Breakdown:** | 82.4161% | 17.5839% | 100.0% |

D

| Plant Acct | Electric | Steam | Total | Factor |
|---|---|---|---|---|
| 312 | 68,869,660 | 23,505,549 | 92,375,208 | |
| | 74.5543% | 25.4457% | | A |
| 314 | 97.9069% | 2.0931% | | B |
| 316 | 67.8573% | 32.1427% | | |

**Notes:**

Plant Data provided by property accounting - Powerplant Query. See Excel file "Steam & Lake Road PP Query"

For purposes of preparing the SJLP Lake Road Allocation Schedule Accounts 310 thru 316 are placed in two categories as follows:
1) 100% Electric and 2) Allocated to Electric Plant.

Lake Road Unit 1 thru Unit 4 amounts are included in the "100% Electric" category. This does not include the Boilers which are Allocated
Lake Road Common-RO-1060 acct 31000 Land only is included in the "100% Electric" category.
Lake Road 340-346 other production in the "100% Electric" category

All other asset locations are included in the "Allocated to Electric Plant" category.
Lake Road Intangible plant, Industrial steam plant, Other production plant and General plant are not included in either category.

KCP&L Greater Missouri Operations

## 900 lb STEAM DEMAND ALLOCATION FACTOR

**Demand and Utilization Factors**

| | | | | |
|---|---|---|---|---|
| Calculated fuel for max sales | | 471.8 | | |
| Fuel Energy for Generation | = | 1,444.5 | **32.6621%** | A |

Schedule TMR-5, Wkpr 1

KCP&L Greater Missouri Operations

**Industrial Steam Allocation**
**900 lb Steam Demand Detail**

Maximum coincident demand for steam customers in 2015, 2016 and 2017. (mmBtus)

| | | 2015 | | | | | | | | | | | | 2016 | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | January | February | March | April | May | June | July | August | September | October | November | December | January | February | March | April | May | June | July | August |
| Maximum hourly 155# steam sales | MmBtu/Hr | 404.1 | 400.4 | 409.5 | 359.1 | 357.0 | 375.9 | 333.9 | 355.1 | 336.7 | 336.5 | 348.2 | 358.3 | 380.7 | 391.3 | 384.4 | 361.0 | 353.0 | 327.1 | 314.8 | 316.9 |
| Maximum hourly 155# steam sales | Mlbs/Hr | 313.4 | 311.4 | 318.2 | 278.7 | 278.0 | 292.1 | 260.1 | 275.7 | 323.9 | 261.2 | 269.8 | 277.5 | 297.3 | 303.9 | 282.9 | 280.0 | 272.9 | 253.2 | 244.0 | 321.3 |
| Day | | 14 | 27 | 2 | 8 | 12 | 4 | 10 | 17 | 3 | 10 | 23 | 31 | 20 | 10 | 31 | 1 | 3 | 8 | 7 | 6 |
| Time | | 1942 | 1945 | 2322 | 1747 | 1936 | 2227 | 1139 | 1804 | 2008 | 1808 | 931 | 111 | 1947 | 304 | 346 | 440 | 156 | 508 | 1105 | 158 |
| Maximum hourly Total steam sales (155# + 850#) | MmBtu/Hr | 431.1 | 430.4 | 433.4 | 387.6 | 390.6 | 409.5 | 381.7 | 382.2 | 370.8 | 388.9 | 384.7 | 384.2 | 409.8 | 424.1 | 398.2 | 392.4 | 385.7 | 358.7 | 344.3 | 350.7 |
| Maximum hourly Total steam sales (155# + 850#) | Mlbs/Hr | 335.2 | 335.9 | 337.5 | 301.8 | 304.6 | 319.4 | 282.7 | 297.6 | 343.3 | 287.6 | 299.5 | 299.3 | 320.9 | 330.6 | 310.3 | 305.5 | 300.0 | 278.7 | 267.9 | 343.5 |
| Day | | 6 | 23 | 2 | 8 | 12 | 4 | 10 | 17 | 3 | 9 | 23 | 1 | 20 | 22 | 3 | 7 | 14 | 8 | 9 | 6 |
| Time | | 2336 | 2055 | 2322 | 1747 | 1938 | 2226 | 1139 | 1804 | 2008 | 1533 | 931 | 132 | 1947 | 900 | 1314 | 214 | 210 | 508 | 947 | 158 |

Note:
The MMBtu/Hr values listed above are the energy in the steam, not the energy in the fuel. The fuel energy value can be found by dividing by 81.5%, the weighted average boiler efficiency.

Calculated Fuel for steam sales avg peak based on 81.5% efficiancy

Note:
Per 2010 SPP Capability Test
Per PSC Heat Rate Tests

**900lb Steam Demand Factor =**

Calculated fuel for max sales / Fuel Energy for Generation =

| Net MW Rating | Gross MW | GTHR MmBtu/GMwh | Steam Energy For Turbine MmBtu/Hr | Fuel Energy For Generation MmBtu/Hr | |
|---|---|---|---|---|---|
| 21.7 | 23.2 | 9.4 | 218 | 268 | 81.5% Weighted Average Blr Eff |
| 28.4 | 28.6 | 12.5 | 358 | 439 | 81.5% Weighted Average Blr Eff |
| 11 | 12.2 | 17.8 | 217 | 266 | 81.5% Weighted Average Blr Eff |
| 59.1 | 64 | | 793 | 972.7 | |

Schedule TMR-5, Wkpr 1

**KCP&L Greater Missouri Operations**

**Industrial Steam Allocation**
**900 lb Steam Demand Detail**

| | | | | | | | | | | 2017 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | September | October | November | December | January | February | March | April | May | June | July | August | September | October | November | December | |
| Maximum hourly 155# steam sales | MmBtu/Hr | 347.9 | 346.4 | 337.5 | 374.3 | 378.3 | 372.4 | 356.0 | 350.4 | 361.9 | 317.4 | 340.0 | 306.6 | 306.5 | 336.2 | 368.4 | 397.9 | |
| Maximum hourly 155# steam sales | Mlbs/Hr | 269.4 | 268.7 | 261.6 | 291.0 | 292.3 | 288.1 | 276.6 | 273.0 | 283.5 | 246.5 | 236.7 | 237.8 | 238.1 | 260.7 | 287.0 | 309.8 | |
| Day | | 29 | 27 | 15 | 16 | 12 | 28 | 15 | 11 | 9 | 1 | 21 | 28 | 8 | 23 | 30 | 30 | |
| Time | | 2102 | 1031 | 1759 | 1707 | 1012 | 227 | 1255 | 451 | 1452 | 945 | 1303 | 935 | 2229 | 954 | 1020 | 558 | Average MM |
| Maximum hourly Total steam sales (155# + 850#) | MmBtu/Hr | 377.8 | 377.0 | 366.1 | 403.8 | 412.4 | 405.6 | 382.1 | 387.1 | 388.2 | 351.6 | 333.9 | 333.0 | 338.9 | 367.8 | 394.9 | 423.5 | 384.5 |
| Maximum hourly Total steam sales (155# + 850#) | Mlbs/Hr | 293.7 | 293.8 | 284.8 | 314.9 | 319.8 | 315.5 | 301.2 | 302.6 | 304.8 | 274.2 | 260.9 | 259.2 | 264.4 | 286.3 | 308.0 | 330.6 | |
| Day | | 29 | 27 | 16 | 16 | 12 | 28 | 15 | 11 | 9 | 1 | 21 | 28 | 8 | 23 | 30 | 30 | |
| Time | | 2102 | 1644 | 331 | 1707 | 1012 | 227 | 1255 | 451 | 1452 | 945 | 1303 | 935 | 2229 | 954 | 1020 | 558 | |
| Note: | | | | | | | | 471.8 | mmBtu/hr | | | | | | | | | |
| The MMBtu/Hr values listed above are the energy in the steam, not | | | | | | | | | | | | | | | | | | |
| Note: | | | | | | | | | | | | | | | | | | |
| Per 2010 SPP Capability Test: | | | | | | | | 471.8 | = | | | 32.6621% | | | | | | |
| Per PSC Heat Rate Tests | | | | | | | | 1444.5 | | | | | | | | | | |
| | Net MW Rating | | | | | | | | | | | | | | | | | |
| | 21.7 | | | | | | | | | | | | | | | | | |
| | 26.4 | | | | | | | | | | | | | | | | | |
| | 11 | | | | | | | | | | | | | | | | | |
| | 59.1 | | | | | | | | | | | | | | | | | |

KCP&L Greater Missouri Operations

**Fuel Oil Demand Allocation Factor**
**Allocation of Fuel Inventory**

**Maximum coincident demand for steam customers in 2015, 2016 and 2017 (mmBtus)**

| | | 2015 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | January | February | March | April | May | June | July | August | September | October | November | December |
| Maximum hourly 155# steam sales | MmBtu/Hr | 404.1 | 400.4 | 409.5 | 359.1 | 357.0 | 375.9 | 333.9 | 355.1 | 336.7 | 336.5 | 348.2 | 358.3 |
| Maximum hourly 155# steam sales | Mlbs/Hr | 313.4 | 311.4 | 318.2 | 278.7 | 278.0 | 292.1 | 260.1 | 275.7 | 323.9 | 261.2 | 269.8 | 277.5 |
| Day | | 14 | 27 | 2 | 8 | 12 | 4 | 10 | 17 | 3 | 10 | 23 | 31 |
| Time | | 1942 | 1945 | 2322 | 1747 | 1936 | 2227 | 1139 | 1804 | 2008 | 1808 | 931 | 111 |
| Maximum hourly Total steam sales (155# + 850#) | MmBtu/Hr | 431.1 | 430.4 | 433.4 | 387.6 | 390.6 | 409.5 | 361.7 | 382.2 | 370.8 | 368.9 | 384.7 | 384.2 |
| Maximum hourly Total steam sales (155# + 850#) | Mlbs/Hr | 335.2 | 335.9 | 337.5 | 301.8 | 304.6 | 319.4 | 282.7 | 297.6 | 343.3 | 287.6 | 299.5 | 299.3 |
| Day | | 6 | 23 | 2 | 8 | 12 | 4 | 10 | 17 | 3 | 9 | 23 | 1 |
| Time | | 2336 | 2055 | 2322 | 1747 | 1936 | 2226 | 1139 | 1804 | 2008 | 1533 | 931 | 132 |

| | | 2016 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | January | February | March | April | May | June | July | August | September |
| Maximum hourly 155# steam sales | MmBtu/Hr | 380.7 | 391.3 | 364.4 | 361.0 | 353.0 | 327.1 | 314.8 | 316.9 | 347.9 |
| Maximum hourly 155# steam sales | Mlbs/Hr | 297.3 | 303.9 | 282.9 | 280.0 | 272.9 | 253.2 | 244.0 | 321.3 | 269.4 |
| Day | | 20 | 10 | 31 | 1 | 3 | 8 | 7 | 6 | 29 |
| Time | | 1947 | 304 | 346 | 440 | 156 | 508 | 1105 | 158 | 2102 |
| Maximum hourly Total steam sales (155# + 850#) | MmBtu/Hr | 409.8 | 424.1 | 398.2 | 392.4 | 385.7 | 358.7 | 344.3 | 350.7 | 377.8 |
| Maximum hourly Total steam sales (155# + 850#) | Mlbs/Hr | 320.9 | 330.6 | 310.3 | 305.5 | 300.0 | 278.7 | 267.9 | 343.5 | 293.7 |
| Day | | 20 | 22 | 3 | 7 | 14 | 8 | 9 | 6 | 29 |
| Time | | 1947 | 900 | 1314 | 214 | 210 | 508 | 947 | 158 | 2102 |

Calculated Fuel for steam sales avg peak based on 81.5% efficiancy 471.8 mmBtu/hr

Note:
The MMBtu/Hr values listed above are the energy in the steam, not the energy in the fuel. The fuel energy value can be found by dividing by 81.5%, the weighted average boiler efficiency.
Generator 2 and Boiler 5 are not included in the calculation since Boiler 5 is not capable of burning fuel oil. Boiler 5 and Turbine 2 were installed together and sized accordingly.
Per 2010 SPP Capability Test
Per PSC Heat Rate Tests

**Oil Demand factor**

Calculated Fuel Oil for Max Sales / Fuel Oil for Generation and Max Steam Sales = 471.8 / 3587.4 = 13.15%

| | Net MW Rating | Gross MW | HR MmBtu/GMwh | Steam Energy For Turbine MmBtu/Hr | Fuel Energy For Generation MmBtu/Hr | |
|---|---|---|---|---|---|---|
| Generator 1 | 21.7 | 23.2 | 9.4 | 218 | 268 | 81.5% Weighted Average Blr Eff |
| Generator 2 | 26.4 | 28.6 | 12.5 | See notes | See notes | 81.5% Weighted Average Blr Eff |
| Generator 3 | 11 | 12.2 | 17.8 | 217 | 266 | 81.5% Weighted Average Blr Eff |
| Generator 4 | 97.5 | 103.4 | 9.981 | | 1032 | |
| Generator 5 | 62 | 65 | 15.235 | | 890 | |
| Generator 6 | 21 | 21 | 13.488 | | 283 | |
| Generator 7 | 21 | 21 | 13.144 | | 276 | |
| Total | 260.6 | 274.4 | | | 3115.6 | |

Schedule TMR-5, Wkpr 1

KCP&L Greater Missouri Operations

**Fuel Oil Demand Allocation Factor**
**Allocation of Fuel Inventory**

| | | | | | 2017 | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | October | November | December | January | February | March | April | May | June | July | August | September | October | November | December | |
| Maximum hourly 155# steam sales | MmBtu/Hr | 346.4 | 337.5 | 374.3 | 378.3 | 372.4 | 356.0 | 350.4 | 361.9 | 317.4 | 340.0 | 306.6 | 306.5 | 336.2 | 368.4 | 397.9 | |
| Maximum hourly 155# steam sales | Mlbs/Hr | 268.7 | 261.6 | 291.0 | 292.3 | 288.1 | 276.6 | 273.0 | 283.5 | 246.5 | 236.7 | 237.8 | 238.1 | 260.7 | 287.0 | 309.8 | |
| Day | | 27 | 15 | 16 | 12 | 28 | 15 | 11 | 9 | 1 | 21 | 28 | 8 | 23 | 30 | 30 | |
| Time | | 1031 | 1759 | 1707 | 1012 | 227 | 1255 | 451 | 1452 | 945 | 1303 | 935 | 2229 | 954 | 1020 | 558 | Average MM |
| Maximum hourly Total steam sales (155# + 850#) | MmBtu/Hr | 377.0 | 366.1 | 403.8 | 412.4 | 406.6 | 382.1 | 387.1 | 388.2 | 351.6 | 333.9 | 333.0 | 338.9 | 367.8 | 394.9 | 423.5 | 384.5 |
| Maximum hourly Total steam sales (155# + 850#) | Mlbs/Hr | 293.8 | 284.8 | 314.9 | 319.8 | 315.5 | 301.2 | 302.6 | 304.8 | 274.2 | 260.9 | 259.2 | 264.4 | 286.3 | 308.0 | 330.6 | |
| Day | | 27 | 16 | 16 | 12 | 28 | 15 | 11 | 9 | 1 | 21 | 28 | 8 | 23 | 30 | 30 | |
| Time | | 1644 | 331 | 1707 | 1012 | 227 | 1255 | 451 | 1452 | 945 | 1303 | 935 | 2229 | 954 | 1020 | 558 | |

Note:
The MMBtu/Hr values listed above are the energy in the steam, not
Generator 2 and Boiler 5 are not included in the calculation since E
Per 2010 SPP Capability Test
Per PSC Heat Rate Tests

| | Net MW Rating |
|---|---|
| Generator 1 | 21.7 |
| Generator 2 | 26.4 |
| Generator 3 | 11 |
| Generator 4 | 97.5 |
| Generator 5 | 62 |
| Generator 6 | 21 |
| Generator 7 | 21 |
| Total | 260.6 |

## KCP&L Greater Missouri Operations
## A&G FACTOR

GMO Electric Plant in-Service - 2016
Per GMO Form 1, Pg 204-207 excl ARO's

| | |
|---|---|
| Total GMO Electric Plant in-Service | **3,669,155,425** |
| Less: ARO 317 | **24,010,288** |
| Less: ARO 347 | **125,497** |
| Less: ARO 399 | **16,950** |
| Total GMO Electric Plant in-Service (excl ARO's) | 3,645,002,690 |

**50% O&M/50% Plant Allocation Method**

| | | | | | | |
|---|---|---|---|---|---|---|
| O&M Dec 2016 Surveillance Report | | | | | | |
| **Electric** | **98.8437%** | | | | | |
| **Steam** | **1.1563%** | **50%** | **0.5782%** | | | |
| Plant | | | | | | |
| **Elec** | 99.1377% | | | | | |
| **Steam** | **0.8623%** | **50%** | **0.4311%** | **1.0093%** | A | #14 |

| | | | | |
|---|---|---|---|---|
| Elec & Steam | 3,645,002,690 | | | |
| Steam After Alloc | $ (31,430,255) | **0.8623%** | B | #3 |
| Electric | 3,613,572,435 | **99.1377%** | B | |
| | | 100.000% | | |

KCP&L Greater Missouri Operations
O&M FACTOR

**Industrial Steam Allocation**
Source: Amy Murray - Regulatory Affairs

**1. Payroll Allocation Factors - Steam v Electric**

| | | | |
|---|---|---|---|
| Annual SJLP Iatan Payroll for O&M - 2016 Actual | $ 2,485,259 | (B) | |
| Annual SJLP Lake Road Payroll for O&M - 2016 Actual | 5,915,992 | (A) | |
| Annual MOPUB Sibley ,Iatan, JEC for O&M - 2016 Actual | 13,223,137 | (C) | |
| Total GMO 2016 Payroll charged to O&M | $ 21,624,389 | | |
| LR Payroll for Steam Business | $ 1,478,998 | | |
| Payroll Percentage for O&M Allocation | 6.8395% | A | #13 |

**2. Payroll Applicable to Steam Business:**

| Lake Road Production Payroll by Account: | 2016 Payroll Charged to O&M | Steam Percentage | Total Steam Payroll |
|---|---|---|---|
| 500000 | 301,186 | | |
| 502000 | 383,788 | | |
| 502001 | 1,323,956 | | |
| 502004 | 54,825 | | |
| 502005 | 5,524 | | |
| 502012 | 212,290 | | |
| 502015 | 309 | | |
| 505000 | 3,165 | | |
| 505007 | 4,912 | | |
| 505010 | 957,206 | | |
| 505011 | 2 | | |
| 506000 | 836,774 | | |
| 510000 | 702,420 | | |
| 511000 | 131,490 | | |
| 511002 | 11,534 | | |
| 512000 | 124,732 | | |
| 512001 | 26,453 | | |
| 512002 | 9,855 | | |
| 512004 | 30,540 | | |
| 512005 | 10,956 | | |
| 512006 | 79,740 | | |
| 512007 | 39,274 | | |
| 512008 | 186,366 | | |
| 512010 | 126,737 | | |
| 512011 | 149,707 | | |
| 512012 | 15,992 | | |
| 513000 | 190 | | |
| 513001 | 107,161 | | |
| 513003 | 16,673 | | |
| 513006 | 50,452 | | |
| 514000 | 11,784 | | |
| Allocated | $ 5,915,992 | 25.00% | $ 1,478,998 |
| Industrial Steam Distrib Accounts (588730 & 598730) | | | |
| Total Steam | | | |

Note: Used the 'Total Plant Coal Burn Allocation Factor' to determine the Steam % above.
(A) LR payroll to accounts 500, 502-507, 510-514 only
(B) SJLP Iatan payroll (dept 115) to accounts 500, 502-507, 510-514 only
(C) MPS Iatan and Sibley payroll to accounts 500, 502-507, 510-514 only

KCP&L Greater Missouri Operations

O&M, A&G, OtherTaxes

Revenue Requirements Model Schedule 2

| Account No. | Description | Juris Factor No. | Allocator Factor | Allocation based on |
|---|---|---|---|---|
| | **Operating Expenses** | | | |
| | *Electric Operating Expense* | | | |
| 500000 | Prod-Steam Oper-Supv & Enginr | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 500000E | Prod-Steam Oper-Supv & Enginr-Elec | 1,1 | 100% Electric | |
| 501000 | Fuel Exp-Deliv Cost Coal Burn | 4,1 | 100% Electric | |
| 501020 | Fuel on System Steam | 4,1 | 100% Electric | |
| 501030 | Fuel Off-System Steam (bk20) | 4,1 | 100% Electric | |
| 501033 | FuelSteamInterUN/IntraST(bk11) | 4,1 | 100% Electric | |
| 501300 | Fuel Exp-Additives - Limestone | 4,1 | 100% Electric | |
| 501400 | Fuel Exp-Residuals | 4,1 | 100% Electric | |
| 501420 | Fuel Exp-Residuals Non FAC | 4,1 | 100% Electric | |
| 501450 | Fuel Exp-Residuals-Landfills | 4,1 | 100% Electric | |
| 501500 | Fuel Handling Costs | 4,1 | 100% Electric | |
| 501501 | Fuel Hndlg-Oil Purch Exp-Start | 4,1 | 100% Electric | |
| 501502 | Fuel Hndlg-Coal Pile Mgmt-Pwr | 4,1 | 100% Electric | |
| 501503 | Fuel Handling Negot Transp Cnt | 4,1 | 100% Electric | |
| 501504 | Fuel Hndlg-Plan Fuel Req-Pwr P | 4,1 | 100% Electric | |
| 501506 | Fuel Hndlg-Receive Coal | 4,1 | 100% Electric | |
| 501507 | Fuel Hndlg-Fossil Fuel Unload | 4,1 | 100% Electric | |
| 501508 | Fuel Handling - Stacker | 4,1 | 100% Electric | |
| 501509 | Fuel Handling - Coal Pile | 4,1 | 100% Electric | |
| 501510 | Fuel Handling - Conveyor | 4,1 | 100% Electric | |
| 501700 | Fuel Expense Industrial Steam | 2,2 | 100% Steam | |
| 502000 | Steam Oper-City Water | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 502001 | Steam Oper-Boiler | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 502002 | Steam Oper-Nitrogen | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 502004 | Steam Oper-Water | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 502005 | Steam Oper-Condensate | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 502012 | Steam Oper- Ash | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 502014 | Steam Oper-Air Pollution Contr | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 502015 | Steam Oper-Water Pollution Con | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 502020 | Steam Ops Apx Precipitator | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 502021 | Steam Ops ACQ Baghouse | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 502022 | Steam Ops Wet Gas Scrubber | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 502024 | Steam Ops AQC Scr | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 502025 | Steam Ops Activated CO2 Inject | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 504100 | Steam Transfer Exp | 2,2 | 100% Steam | |
| 505000 | Steam Ops Elec Exp Other | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 505004 | Steam Op Ele Exp Comp Air Sys | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 505005 | Steam Ops Ele Exp Cooling Sys | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 505007 | Steam Ops Ele Exp Facilities | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 505010 | Steam Ops Ele Exp Turbine Gen | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 505011 | Steam Ops Ele Exp Aux System | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 506000A | Misc Steam Power Operations | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 506000E | Steam Ops Misc Steam Power Exp -Elec | 1,1 | 100% Electric | |
| 506000S | Steam Ops Misc Steam Power Exp -Steam | 2,2 | 100% Steam | |
| 507000 | Steam Power Operations - Rents | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 509000A | El Op Exp-Allowances | 4,1 | 100% Electric | |
| 509000E | El Op Exp-Allowances-Elec | 1,1 | 100% Electric | |
| 546000 | Prod-Turbine Oper-Supv & Engnr | 3,1 | 100% Electric | |
| 547000 | Oth Prod Fuel | 4,1 | 100% Electric | |
| 547020 | Fuel On-System Other Prod | 4,1 | 100% Electric | |
| 547027 | Fuel OnSys Oth Prod-Demand | 4,1 | 100% Electric | |
| 547030 | Fuel Off-Sys Other Prod (bk20) | 4,1 | 100% Electric | |
| 547033 | FuelOtherInterUN/IntraST(bk11) | 4,1 | 100% Electric | |
| 547100 | Oth Prod Fuel Handling | 4,1 | 100% Electric | |
| 547102 | Comb Turbine-Gas Purch Exp | 4,1 | 100% Electric | |
| 548000 | Comb Turbine-City Water | 3,1 | 100% Electric | |
| 548002 | Comb Turbine-AQC- | 3,1 | 100% Electric | |
| 548003 | Comb Turbine-Turb/Genr-CT | 3,1 | 100% Electric | |
| 549000 | CombTurbine Oper-Misc Other | 3,1 | 100% Electric | |
| 549001 | Comb Turbine - Facilities | 3,1 | 100% Electric | |
| 555000 | Purch Pwr-Enrgy & Cpcty Pur-Al | 4,1 | 100% Electric | |
| 555005 | Purch Pwr-Capacity Purch-Gardn | 3,1 | 100% Electric | |
| 555021 | Base Pwr On-Sys Interco (bk10) | 4,1 | 100% Electric | |
| 555030 | Purchased Power Off-Sys Sales | 4,1 | 100% Electric | |
| 555031 | Purch Pwr Off-System Interunit | 4,1 | 100% Electric | |
| 555032 | PurchasePower Intrastate(bk11) | 4,1 | 100% Electric | |
| 555035 | Purchased Power Off-Sys-WAPA | 4,1 | 100% Electric | |
| 556000 | System Control and Load Dispath | 4,1 | 100% Electric | |
| 557000 | Prod-Other-Other Expenses | 4,1 | 100% Electric | |
| 557100 | Other Production Exp Riders | 1,1 | 100% Electric | |
| 560000 | Transm Oper-Superv & Enginring | 8,1 | 100% Electric | |
| 561000 | Transm Oper-Load Dispatching | 8,1 | 100% Electric | |
| 561200 | Trans Op-Ld Disptch-Mon&Oper | 8,1 | 100% Electric | |
| 561300 | Trans Op-Ld Disptch-Serv&Sched | 8,1 | 100% Electric | |
| 561400 | Trans Op-Schd,Contr & Dis Serv | 8,1 | 100% Electric | |
| 561600 | Trans Op-Service Studies | 8,1 | 100% Electric | |
| 561800 | Trans Op-Reli Plan&Std Dv-RTO | 8,1 | 100% Electric | |
| 562000 | Transm Oper-Station Exp | 8,1 | 100% Electric | |
| 563000 | Transm Oper-Overhead Line Oper | 8,1 | 100% Electric | |
| 563002 | Transm Oper-Inspect OH Lines-G | 8,1 | 100% Electric | |
| 563010 | Transm Oper-Lost & Standby Tim | 8,1 | 100% Electric | |
| 564000 | Trans Op Ug Lines | 8,1 | 100% Electric | |
| 565000 | Transm Oper-Elec Tr-By Others | 8,1 | 100% Electric | |

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**O&M, A&G, OtherTaxes**

**Revenue Requirements Model Schedule 2**

| Account No. | Description | Juris Factor No. | Allocator Factor | Allocation based on |
|---|---|---|---|---|
| 565020 | Transm Op Trans Res Load Chg | 8,1 | 100% Electric | |
| 565027 | Transm Oper-Elec Tr-Demand | 8,1 | 100% Electric | |
| 565030 | Transm Oper-Elec Tr-OffSys | 8,1 | 100% Electric | |
| 566000 | Transm Oper-Misc Expense | 8,1 | 100% Electric | |
| 567000 | Transm Oper-Rents | 8,1 | 100% Electric | |
| 575700 | Trans Op-Mkt Mon&Comp Ser-RTO | 8,1 | 100% Electric | |
| 580000 | Distr Oper-Superv & Enginring | 5,1 | 100% Electric | |
| 581000 | Distr Oper-Load Dispatching | 5,1 | 100% Electric | |
| 582000 | Distr Oper-Station Expense | 5,1 | 100% Electric | |
| 583000 | Distr Oper-Overhead Lines | 5,1 | 100% Electric | |
| 583001 | Distr Oper-OH Transformer | 5,1 | 100% Electric | |
| 583002 | Distr Oper-OH Trsfmr Cptzd | 5,1 | 100% Electric | |
| 584000 | Distr Oper-Underground Lines | 5,1 | 100% Electric | |
| 584001 | Distr Oper-UG Transformer | 5,1 | 100% Electric | |
| 584002 | Distr Oper-UG Trsfmr Cptzd | 5,1 | 100% Electric | |
| 585001 | Distr Oper-Operate St Light Sy | 5,1 | 100% Electric | |
| 585002 | Distr Oper-Traffic Signals | 5,1 | 100% Electric | |
| 586000 | Distr Oper-Meter Exp-Con/Disco | 5,1 | 100% Electric | |
| 586001 | Distr Oper-Meter Expenses | 5,1 | 100% Electric | |
| 586002 | Distr Oper-Meter Cptzd | 5,1 | 100% Electric | |
| 587000 | Distr Oper-Customer Inst | 5,1 | 100% Electric | |
| 588000 | Distr Oper-Misc Distr Expense | 5,1 | 100% Electric | |
| 588730 | Dist Ops Ind Steam | 2,2 | 100% Steam | |
| 589000 | Distr Oper-Rents | 5,1 | 100% Electric | |
| | **A&G Operating Expense** | | | |
| 901000 | Customer Acct Supervision Exp | 1,1 | 100% Electric | |
| 902000 | Meter Reading Expense | 1,1 | 100% Electric | |
| 903000 | Customer Record/Collection Exp | 1,1 | 100% Electric | |
| 903300 | Cust Accnts-Dollar-Aide Match | 1,1 | 100% Electric | |
| 904000 | Uncollectible Accounts Exp | 1,1 | 100% Electric | |
| 905000 | Miscellaneous Customer Acct Ex | 1,1 | 100% Electric | |
| 907000 | Customer Svc Supervision Exp | 1,1 | 100% Electric | |
| 908000 | Customer Assistance Expense | 1,1 | 100% Electric | |
| 908100 | Customer Assistance Expense RIDER | 1,1 | 100% Electric | |
| 908500 | Cust Assistance Expense EEIA Program Cost | 1,1 | 100% Electric | |
| 909000 | Info/Instruct Advertising Exp | 1,1 | 100% Electric | |
| 910000 | Miscellaneous Cust Svc Exp | 1,1 | 100% Electric | |
| 911000 | Sales Supervision Expense | 1,1 | 100% Electric | |
| 912000 | Sales Expense | 1,1 | 100% Electric | |
| 913000 | Sales Exp-Oper-Advertising | 1,1 | 100% Electric | |
| 916000 | Sales Exp-Oper-Misc Expense | 1,1 | 100% Electric | |
| 920000A | A&G Labor Expense | 6,14 | Electric After Steam Allocation (A&G) | 50/50 weighting of the Allocated Plant Base Factor and the Allocated O&M Factor |
| 920000E | A&G Labor Expense-100% Retail | 1,1 | 100% Electric | |
| 920000S | A&G Labor - Amort of Merger Trans Steam | 2,2 | 100% Steam | |
| 921000 | A&G Exp-Oper-Office Exp | 6,14 | Electric After Steam Allocation (A&G) | 50/50 weighting of the Allocated Plant Base Factor and the Allocated O&M Factor |
| 921202 | A&G Alloctn-to JO Partners | 6,14 | Electric After Steam Allocation (A&G) | 50/50 weighting of the Allocated Plant Base Factor and the Allocated O&M Factor |
| 921999 | Misc Issue Settlements | 6,14 | Electric After Steam Allocation (A&G) | 50/50 weighting of the Allocated Plant Base Factor and the Allocated O&M Factor |
| 922000 | A&G Expenses Transferred | 6,14 | Electric After Steam Allocation (A&G) | 50/50 weighting of the Allocated Plant Base Factor and the Allocated O&M Factor |
| 922050 | KCPL Bill of Common Use Plant | 6,14 | Electric After Steam Allocation (A&G) | 50/50 weighting of the Allocated Plant Base Factor and the Allocated O&M Factor |
| 923000A | Outside Services Employed | 6,14 | Electric After Steam Allocation (A&G) | 50/50 weighting of the Allocated Plant Base Factor and the Allocated O&M Factor |
| 923000E | Outside Services Employed-Retail | 1,1 | 100% Electric | |
| 923000S | Outside Services-Amort of Merger Transition - Steam | 2,2 | 100% Steam | |
| 923100 | GPES A&G Trnsf-Depr Int Tax | 6,14 | Electric After Steam Allocation (A&G) | 50/50 weighting of the Allocated Plant Base Factor and the Allocated O&M Factor |
| 924000 | Property Insurance | 7,14 | Electric After Steam Allocation (A&G) | 50/50 weighting of the Allocated Plant Base Factor and the Allocated O&M Factor |
| 925000 | Injuries and Damages | 6,14 | Electric After Steam Allocation (A&G) | 50/50 weighting of the Allocated Plant Base Factor and the Allocated O&M Factor |
| 925050 | Injuries & Damages xfer Constr | 6,14 | Electric After Steam Allocation (A&G) | 50/50 weighting of the Allocated Plant Base Factor and the Allocated O&M Factor |
| 926000A | Employee Pensions & Benefits | 6,14 | Electric After Steam Allocation (A&G) | 50/50 weighting of the Allocated Plant Base Factor and the Allocated O&M Factor |
| 926000E | Employee Pensions & Benefits-Retail | 1,1 | 100% Electric | |
| 926000S | Employee Pensions & Benefits - Steam | 2,2 | 100% Steam | |
| 926500 | Empl Pens and Bens Loadings | 6,14 | Electric After Steam Allocation (A&G) | 50/50 weighting of the Allocated Plant Base Factor and the Allocated O&M Factor |
| 926510 | Benefits on Construct | 6,14 | Electric After Steam Allocation (A&G) | 50/50 weighting of the Allocated Plant Base Factor and the Allocated O&M Factor |
| 926511 | PR Tax, Pens & Bnfits on O&M | 6,14 | Electric After Steam Allocation (A&G) | 50/50 weighting of the Allocated Plant Base Factor and the Allocated O&M Factor |
| 926730 | Empl Pens and Bens Ind Steam | 2,2 | 100% Steam | |
| 928000A | Regulatory Commission Expense - Allocated | 6,14 | Electric After Steam Allocation (A&G) | 50/50 weighting of the Allocated Plant Base Factor and the Allocated O&M Factor |
| 928000E | Regulatory Commission Expense - All Electric | 1,1 | 100% Electric | |
| 928001A | Reg Comm Exp-MPSC Assessment | | | |
| 928001E | Reg Comm Exp-MPSC Assessment - Elec | | | |
| 928001S | Reg Comm Exp-MPSC Assessment - Steam | | | |
| 928003 | Reg Comm Exp-FERC Assessment | | | |
| 928011A | Reg Comm Exp-Mo Proceeding Exp | | | |
| 928011E | Reg Comm Exp-Mo Proceeding Exp - Elec | | | |
| 928011S | Reg Comm Exp-Mo Proceeding Exp - Steam | | | |
| 928012 | Reg Comm Exp-Ks Proceeding Exp | | | |
| 928023 | Reg Comm Exp-FERC Proceedings | | | |
| 928030 | Reg Comm Exp-Load Research Pgm | | | |
| 928040 | Reg Comm Exp-Misc Tariff Filin | | | |
| 929000 | Duplicate Charges-Credit | 6,14 | Electric After Steam Allocation (A&G) | 50/50 weighting of the Allocated Plant Base Factor and the Allocated O&M Factor |
| 930100 | General Advertising Expense | 6,14 | Electric After Steam Allocation (A&G) | 50/50 weighting of the Allocated Plant Base Factor and the Allocated O&M Factor |
| 930200 | Miscellaneous General Expense | 6,14 | Electric After Steam Allocation (A&G) | 50/50 weighting of the Allocated Plant Base Factor and the Allocated O&M Factor |
| 930201 | Misc A&G-Board of Dir Fees | 6,14 | Electric After Steam Allocation (A&G) | 50/50 weighting of the Allocated Plant Base Factor and the Allocated O&M Factor |
| 930220 | Environ Remed-MO Electric | 6,14 | Electric After Steam Allocation (A&G) | 50/50 weighting of the Allocated Plant Base Factor and the Allocated O&M Factor |
| 930230 | Misc A&G-Company Assoc Dues | 6,14 | Electric After Steam Allocation (A&G) | 50/50 weighting of the Allocated Plant Base Factor and the Allocated O&M Factor |
| 930231 | Misc A&G-Edison Elect Inst Due | 6,14 | Electric After Steam Allocation (A&G) | 50/50 weighting of the Allocated Plant Base Factor and the Allocated O&M Factor |
| 930232 | Misc A&G-EPRI Research Subscri | 6,14 | Electric After Steam Allocation (A&G) | 50/50 weighting of the Allocated Plant Base Factor and the Allocated O&M Factor |
| 930242 | Misc A&G-Bond Expense | 6,14 | Electric After Steam Allocation (A&G) | 50/50 weighting of the Allocated Plant Base Factor and the Allocated O&M Factor |

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Revenue Requirements Model Schedule 2

| Account No. | Description | Juris Factor No. | Allocator Factor | Allocation based on |
|---|---|---|---|---|
| 930250 | Miscellaneous A&G | 6,14 | Electric After Steam Allocation (A&G) | 50/50 weighting of the Allocated Plant Base Factor and the Allocated O&M Factor |
| 931000A | A&G Rent Exp | 6,14 | Electric After Steam Allocation (A&G) | 50/50 weighting of the Allocated Plant Base Factor and the Allocated O&M Factor |
| 931000E | A&G Rent Expense - Elec | 1,1 | 100% Electric | |
| 931002 | Rent of Equipment | 6,14 | Electric After Steam Allocation (A&G) | 50/50 weighting of the Allocated Plant Base Factor and the Allocated O&M Factor |
| 933000 | Transportation Expense | 6,14 | Electric After Steam Allocation (A&G) | 50/50 weighting of the Allocated Plant Base Factor and the Allocated O&M Factor |
| 933100 | Transportation & O Series Allo | 6,14 | Electric After Steam Allocation (A&G) | 50/50 weighting of the Allocated Plant Base Factor and the Allocated O&M Factor |
| 935000 | A&G Mtce of General Plant | 6,14 | Electric After Steam Allocation (A&G) | 50/50 weighting of the Allocated Plant Base Factor and the Allocated O&M Factor |
| | *Maintenance Expenses* | | | |
| 510000 | Steam Power Maint-Supv & Engin | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 511000 | Steam Power Maint-Structure | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 511002 | Steam Power Maint-Struct-Fac-F | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 512000 | Boiler Plt Maint - | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 512000E | Boiler Plt Maint - Electric | 1,1 | 100% Electric | |
| 512001 | Boiler Plt Maint - FF Unload | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 512002 | Boiler Plt Maint - Stacker | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 512003 | Boiler Plt Maint - Coal Pile | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 512004 | Boiler Plt Maint - Ash | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 512005 | Boiler Plt Maint - Conveyor | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 512006 | Boiler Plt Maint - Fuel | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 512007 | Boiler Plt Maint - Air | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 512008 | Boiler Plt Maint - Water | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 512010 | Boiler Plt Maint - Cond Sys | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 512011 | Boiler Plt Maint - Furnace | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 512012 | Boiler Plt Maint - Aux Steam | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 512020 | Boiler Plt Maint-Default Proc | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 512021 | Maint Boil Plt Baghouse | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 512022 | Maint Boiler Plant Wet Gas Scr | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 512024 | Maint Boiler Plant Scr | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 512025 | Maint Boiler Plant Activated CO2 Inj | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 513000 | Elec Plt Maint - | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 513001A | Elec Plt Maint - FF Turb/Gen | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 513001E | Elec Plt Maint - FF Turb/Gen | 1,1 | 100% Electric | |
| 513001S | Elec Plt Maint - FF Turb/Gen | 2,2 | 100% Steam | |
| 513002 | Elec Plt Maint - Transfer FF | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 513003 | Elec Plt Maint - Aux Elec | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 513006 | Elec Plt Maint - Cooling | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 514000 | Misc Steam Plt - | 3,13 | Electric After Steam Allocation (O&M) | Ratio of the allocated Steam Payroll to total non-fuel production GMO Payroll charged to O&M |
| 551000 | Comb Turbine Mtce-Supv & Engnr | 3,1 | 100% Electric | |
| 552000 | Othr Gen Maint of Structures | 3,1 | 100% Electric | |
| 552001 | CT Mtce Structure-Facilities | 3,1 | 100% Electric | |
| 552002 | Comb Turbine Mtce - Bulk Oil F | 3,1 | 100% Electric | |
| 552003 | Comb Turbine Mtce - Fire CT | 3,1 | 100% Electric | |
| 553000 | Comb Turbine Maint - | 3,1 | 100% Electric | |
| 553001 | Comb Turbine Maint - Comb Turb | 3,1 | 100% Electric | |
| 553100 | Oth Pwr Gen Maint Turb Gen | 3,1 | 100% Electric | |
| 554000 | Comb Turbine Maint- Comp Air | 3,1 | 100% Electric | |
| 568000 | Transm Mtce-Suprv & Enginring | 8,1 | 100% Electric | |
| 569000 | Transm Mtce-Subst Bldg/Grounds | 8,1 | 100% Electric | |
| 570000 | Transm Mtce-Subst Equip | 8,1 | 100% Electric | |
| 570001 | Transm Mtce-Subst Teleco/SCADA | 8,1 | 100% Electric | |
| 570002 | Transm Mtce-Subst Breakers | 8,1 | 100% Electric | |
| 570003 | Transm Mtce-Subst Xfrms/Regltr | 8,1 | 100% Electric | |
| 570004 | Transm Mtce-Subst Bus/Groundin | 8,1 | 100% Electric | |
| 570005 | Transm Mtce-Subst Relay Panels | 8,1 | 100% Electric | |
| 570006 | Trans Maint Subst Capacitr Bnk | 8,1 | 100% Electric | |
| 570007 | Trans Maint Subst Eqp Bat Bkup | 8,1 | 100% Electric | |
| 571000 | Transm Mtce-Overhead Lines | 8,1 | 100% Electric | |
| 571002 | Trans Maint Oh Lines Twr Lghtg | 8,1 | 100% Electric | |
| 571003 | Transm Mtce-Overhead Structure | 8,1 | 100% Electric | |
| 571004 | Transm Mtce-Cndctrs/Devices | 8,1 | 100% Electric | |
| 571005 | Transm Mtce-Tree-Hand Cutting | 8,1 | 100% Electric | |
| 571006 | Transm Mtce-Tree-Mech Cut | 8,1 | 100% Electric | |
| 572000 | Transm Mtce-Underground Lines | 8,1 | 100% Electric | |
| 573000 | Trans Maint of Misc Trans Plan | 8,1 | 100% Electric | |
| 590000 | Distr Mtce-Suprv & Enginring | 5,1 | 100% Electric | |
| 591000 | Distr Mtce-Structures | 5,1 | 100% Electric | |
| 592000 | Distr Mtce-Station Equip | 5,1 | 100% Electric | |
| 592001 | Distr Mtce-Subst Welding | 5,1 | 100% Electric | |
| 592002 | Distr Mtce-Tele/SCADA | 5,1 | 100% Electric | |
| 592003 | Distr Mtce-Subst Breakers | 5,1 | 100% Electric | |
| 592004 | Distr Mtce-Subst Transformers | 5,1 | 100% Electric | |
| 592005 | Distr Mtce-Subst Line/Bus | 5,1 | 100% Electric | |
| 592006 | Distr Mtce-Subst Relay | 5,1 | 100% Electric | |
| 592007 | Dist Mtce Sub Capacitor | 5,1 | 100% Electric | |
| 592008 | Distr Mtce-Sub Battery Bkup | 5,1 | 100% Electric | |
| 593000 | Distr Mtce-OH-Perform Line Cle | 5,1 | 100% Electric | |
| 593001 | Distr Mtce-OH- Wood Poles | 5,1 | 100% Electric | |
| 593002 | Distr Mtce-OH-Poles/Fixtures | 5,1 | 100% Electric | |
| 593003 | Distr Mtce-OH-Conductors/Devic | 5,1 | 100% Electric | |
| 593004 | Distr Mtce-OH-Prop Dmg Uncolle | 5,1 | 100% Electric | |
| 594000 | Distr Mtce-UG-Dist | 5,1 | 100% Electric | |
| 594001 | Distr Mtce-UG-Dist Conduits | 5,1 | 100% Electric | |
| 594002 | Distr Mtce-UG-Conductors/Devic | 5,1 | 100% Electric | |
| 594003 | Distr Mtce-UG Prop Dmg Uncoll | 5,1 | 100% Electric | |
| 595000 | Distr Mtce-Transformers | 5,1 | 100% Electric | |

**KCP&L Greater Missouri Operations**

**O&M, A&G, OtherTaxes**

**Revenue Requirements Model Schedule 2**

| Account No. | Description | Juris Factor No. | Allocator Factor | Allocation based on |
|---|---|---|---|---|
| 595001 | Distr Mtce-Transfm-Rep Dist Po | 5,1 | 100% Electric | |
| 595002 | Distr Mtce-Transfm0Rep Dist Pa | 5,1 | 100% Electric | |
| 595003 | Distr Mtce-Transfm-Repair | 5,1 | 100% Electric | |
| 596000 | Distr Mtce-Street Ltg & Signls | 5,1 | 100% Electric | |
| 596001 | Distr Mtce-St Ltg & Sig-Rpr OH | 5,1 | 100% Electric | |
| 596002 | Distr Mtce-St Ltg & Sig-Rpr UG | 5,1 | 100% Electric | |
| 596003 | Distr Mtce-St Ltg & Sig-Prop D | 5,1 | 100% Electric | |
| 597000 | Distr Mtce-Meters | 5,1 | 100% Electric | |
| 598000 | Distr Mtce-Misc Dist Plt | 5,1 | 100% Electric | |
| 598730 | Dist Mtce Ind Steam | 2,2 | 100% Steam | |
| | **OTHER TAXES** | | | |
| 408101 | State Cap Stk Tax Elec | 7,1 | 100% Electric | |
| 408110 | Earnings Tax Electric | 6,1 | 100% Electric | |
| 408112 | Totit Elec | 6,1 | 100% Electric | |
| 408120 | Property Taxes - Elec | 7,3 | Allocated Plant Base | Ratio of Total GMO Plant excluding ARO's adjusted for the total Steam Allocated Plant |
| 408140 | TOTIT FICA FUTA SUTA | 6,14 | Electric After Steam Allocation (A&G) | 50/50 weighting of the Allocated Plant Base Factor and the Allocated O&M Factor |

## KCP&L Greater Missouri Operations

# Lake Road Fuel Inventory Analysis 11/1/17

### COAL

| | | | | |
|---|---|---|---|---|
| Burn | Jan17-Oct17 | | mmBtus | |
| | | Electric | 11,954 | 0.83% |
| | | Steam | 1,427,761 | 99.17% |
| | | Total | 1,439,715 | |
| Inventory | | | Tons | $$ |
| | | Available | 22,000 | |
| | | Basemat | 13,736 | |
| | | Total | 35,736 | $1,235,394 |
| | | mmbtu's per ton | 17.6 | (8800 Btu's per lb. of coal) |
| | | Total mmbtu's | 628,954 | |
| Allocation | | Steam 60 Day Average burn on Coal | 287,943 | mmbtu's |

Recommendation based on 35,736 tons

| | |
|---|---|
| Electric | 50.00% |
| Steam | 50.00% |

### OIL

| | | |
|---|---|---|
| | mmBtus | |
| Electric | 6,462 | 99.17% |
| Steam | 54 | 0.83% |
| Total | 6,516 | |
| | Barrels | $$ |
| Available | 21,428 | |
| Total | 21,428 | $1,725,424 |
| mmbtu's per barrel | 5.801 | (138,139 Btu's per gallon, 42 gal per barrel)) |
| Total mmbtu's | 124,304 | |

Oil is primarily a reserve fuel for Electricity and Steam. While use of oil for electricity covers generators beyond the 900 lb. system, the allocation should be based on overall capability of the plant to use oil.

KCP&L Greater Missouri Operations

## Steam Equivalent Employment Factor

**From:** John Janorschke
**Sent:** Friday, January 26, 2018 8:38 AM
**To:** Tim Rush <Tim.Rush@kcpl.com>
**Cc:** Aron Branson <Aron.Branson@kcpl.com>; Linda Nunn <Linda.Nunn@kcpl.com>
**Subject:** FW: Steam Equivalent Employment Factor

This documents the calculation for the Equivalent Employment Factor used in our Steam/Electric allocation procedures. Based on a review of each shift, time worked on steam sales for the 8 hour shift are as follows:

| | |
|---|---|
| Control Operator Hi Side, 4/6 and combustion turbines | 0.5 hours |
| Control Operator Rover, red holds, switching, plant rounds and misc. work | 1.0 Hours |
| Control Operator Low Side, 900# boilers, 900# turbines and steam sales | 4.5 Hours |
| Plant Equipment Operator, outside operator for 4/6, 900# steam turbines and misc. | 1.5 Hours |
| Plant Equipment Operator, 900# boilers, CTs, water system and steam sales | 2.5 Hours |
| Total time to steam sales for each 8 hour shift | 10.0 Hours |

Equivalent Employment Factors are as follows:

Steam: Equivalent Employment Factor = 10 Hrs. / 40 Hrs. = 0.25
Electric: Equivalent Employment Factor = 1 - 0.25 = 0.75

**John Janorschke**
Operations Superintendent
Kansas City Power and Light
Lake Road Generation Station
St. Joseph, MO 64504
P | 816.387.6421 C | 816.261.7739

CLEAN CHARGE NETWORK
SCHEDULE CCN

PURPOSE

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

AVAILABILITY

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

HOST PARTICIPATION

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

The maximum number of EV charging stations identified by the Company under this Schedule CCN is 400. The Company may not exceed 400 EV charging stations under this tariff without approval of the State Regulatory Commission.

PROGRAM ADMINISTRATION

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

BILLING OPTIONS

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

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

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

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

CLEAN CHARGE NETWORK
SCHEDULE CCN

RATES FOR SERVICE

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

A. Energy Charge (per kWh)

| | |
|---|---|
| Level 2: | $0.20000 |
| Level 3: | $0.25000 |

B. Session Overstay Charge (optional) (per hour): $0.00 - $6.00

The Energy Charge shall be defined as a flat rate per kWh, and reflect the inclusion of the following riders: (1) Fuel Adjustment Clause (FAC); (2) Renewable Energy Standard Rate Adjustment Mechanism Rider (RESRAM); and (3) Demand-Side Investment Mechanism Rider (DSIM).

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

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

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

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

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

BILLING

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

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

ADJUSTMENTS AND SURCHARGES

The rates hereunder are subject to adjustment as provided in the Tax and License Rider.

REGULATIONS

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