MISSOURI PUBLIC SERVICE COMMISSION

STAFF'S

RATE DESIGN

AND

CLASS COST-OF-SERVICE

REPORT

EMPIRE DISTRICT ELECTRIC COMPANY

CASE NO. ER-2012-0345

Jefferson City, Missouri
December 13, 2012

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REPORT

I. Executive Summary

Staff's rate design recommendations in this case based on Staff's Class Cost-of-Service ("CCOS") study results are that the Commission order Empire District Electric Company ("Empire" or "Company") to implement the following:

1. Adjustments to class revenue responsibilities be made first on a company-wide revenue neutral basis to the residential class, commercial building class and general power class. The Empire residential class should receive a positive 0.5% adjustment. The Empire commercial building class and general power class should receive a negative adjustment of approximately 0.82%. All other classes should receive the system average increase (commercial space heating, special transmission: Praxair, total electric building, feed mill and grain elevator, large power, lighting, and miscellaneous).

2. After having made the recommended revenue neutral adjustments, above, any overall change in revenues the Commission orders should be applied on an equal percentage basis to all classes. Staff further recommends that an additional constraint (revenue requirement after true-up) be placed on which class revenues are moved towards class cost of service to ensure that no class receives an overall reduction in its rate revenues while another customer class receives an overall increase in its rate revenues.

3. Staff recommends that there be a separate DSM cost recovery rate on each rate schedule along with another rate to reflect either: 1) rate including the DSM cost recovery rate (applied to those who have not opted out of DSM), or 2) rate excluding the DSM cost recovery rate (applied to those who opted out of DSM).

4. That the residential customer charge be increased to $13.25.

Staff's CCOS and Rate Design objectives in this report are:

1. To present an overview of Staff's CCOS study and the study results based upon the test year of April 1, 2011, through March 31, 2012, updated through June 30, 2012.

2. Provide the Commission with a rate design recommendation based on each customer class's relative cost-of-service responsibility.

3. Provide methods to implement any Commission-ordered overall change in customer revenue responsibility in rates.

4. Retain, to the extent possible, existing rate schedules, rate structures, and important features of the current rate design and mitigate the potential for rate shock.

Staff's Class Cost-of-Service and Rate Design Report (Report) is organized into the following main sections. They are:

- Executive Summary
- Class Cost-of-Service and Rate Design Overview
- Staff's Class Cost-of-Service Study
- Rate Design
- Loss study
- Fuel Adjustment Clause Tariff Sheets
- Fuel Adjustment Clause Heat Rate and Efficiency Testing

Current Class Revenues and Cost to Serve

Table 1 shows the rate revenue shifts necessary for the current rate revenues from each customer class to exactly match Staff's determination of Empire's cost-of-serving that class as filed in Staff's Cost of Service Report at the high-point rate of return.

Table 1

Summary Results of Staff's CCOS Study - Empire District Electric Company

Customer Class	**Revenue Deficiency**	**CCOS % Increase**	**System Average**	**Neutral Increase**
Residential	$14,226,427	7.67%	3.34%	4.33%
Commercial Building	($584,894)	-1.55%	3.34%	-4.89%
Commercial Space Heating	$472,442	4.92%	3.34%	1.58%
General Power	($2,707,887)	-3.47%	3.34%	-6.81%
Special Transmission Service Contract: Praxair	$32,607	1.01%	3.34%	-2.33%
Total Electric Building	$1,025,956	3.05%	3.34%	-0.29%
Feed Mill and Grain Elevator	$3,665	6.70%	3.34%	3.36%
Large Power	$442,700	0.91%	3.34%	-2.43%
Lighting and Miscellaneous (Street, Private, Special, Miscellaneous)	$563,649	7.75%	3.34%	4.41%
Subtotal	$13,474,665	3.34%	3.34%	0.00%
Interruptible Credits	$342,912			
Total	$13,817,577			

Staff developed its analysis of the cost of serving each class using inputs taken from Staff's Revenue Requirement Cost of Service Report ("COS Report") including the Staff Accounting Schedules filed in this case on November 30, 2012. Staff's recommended revenue requirement for Empire is $5,266,465 to $13,817,579 based on a return on equity ("ROE") range of 8.50% to 9.50%. Staff's revenue requirement as presented in its Accounting Schedules is based on actual results through the June 30, 2012 update period, based on current information. Staff will further update the case for Empire to include actual results for the true-up period ending December 31, 2012.

The results of a CCOS study can be presented either in terms of (1) the rate of return realized for providing service to each class or (2) in terms of the revenue shifts (expressed as negative or positive dollar amounts or percentages) that are required to equalize the utility's rate of return from each class. Staff prefers to present its results in the latter format, i.e., negative or positive dollar amounts or percentages. The results of Staff's analysis are presented in terms of the shifts in revenue that produce an equal rate of return for Empire from each customer class.

A negative amount or percentage indicates revenue from the customer class exceeds the cost of providing service to that class; therefore, to equalize revenues and cost of service, rate revenues should be reduced, i.e., the class is overpaying. A positive amount or percentage indicates revenue from the class is less than the cost of providing service to that class; therefore, to equalize revenues and cost of service, rate revenues should be increased, i.e., the class is underpaying.

The customer classes used in Staff's study correspond to Empire's current rate schedules, except its lighting rate schedules, which Staff combined into one customer class for its study. Aside from its lighting classes, Empire has nine rate schedules: Residential Service ("RG"), Commercial Building Service ("CB"), Commercial Small Heating Service ("SH"), General Power Service ("GP"), Total Electric Building Service ("TEB"), Feed Mill / Grain Elevator Service ("PFM"), Large Power Service ("LP"), and Special Transmission Service Contract: Praxair ("SC-P"). Also, Empire has a Special Transmission Service ("ST") although no customers are currently served under that rate schedule. Staff's rate classes are shown in Table 1 above.

Staff recommends adjustments to the RG, CB, and GP classes which would bring these classes closer to Empire's actual cost to serve each class. Staff recommends that the SH, SC-P, TEB, PFM, LP, lighting and miscellaneous classes receive the system average increase as these classes revenue responsibility are close to Empire's cost to serve them. These adjustments bring certain classes closer to the cost of serving them, while still maintaining rate continuity, rate stability, revenue stability; and minimizing rate shock to any one customer class.

II. Class Cost-of-Service and Rate Design Overview

The purpose of a CCOS study is to determine whether each class of customers is providing the utility with a level of revenue reasonably necessary to cover (1) the utility's investments required to provide service to that class of customers and (2) the utility's ongoing expenses to provide electric service to that class of customers. A CCOS study provides a basis for allocating and/or assigning to the customer classes the utility's total cost of providing electric service to all the customer classes in a manner which best reflects cost causation. Staff's CCOS study is a continuation and refinement of Staff's cost-of-service revenue requirement study, resulting in a determination of the costs incurred in providing electric service to each of Empire's customer classes. Since those costs equate to the utility's revenue requirement, the results of a CCOS study determine class revenue requirements based on the cost responsibility of each customer class for its equitable share of the utility's total annual cost of providing electric service.

Schedule MSS-6 provides fundamental concepts, terminology, and definitions, used in CCOS studies and rate design. It addresses functionalization, classification, and allocation, as used in CCOS studies. It lists generation allocation methods outlined in the National Association of Utility Commissioners ("NARUC") Manual and provides descriptions of the strengths and weaknesses of some of the more common allocation methods used in CCOS studies.

III. Staff's Class Cost-of-Service Study

The results of Staff's CCOS study are shown in Table 1 above. This shows the change to the current rate revenues of each customer class required to exactly match that customer class's rate revenues with Empire's cost to serve that class. The results are also presented, on a revenue neutral basis, as the revenue shifts (expressed as negative or positive dollar amounts or percentages) that are required to equalize the utility's rate of return from each class.

"Revenue neutral" means that the revenue shifts among classes do not change the utility's total system revenues. The revenue neutral format aids in comparing revenue deficiencies between customer classes and makes it easier to discuss revenue neutral shifts between classes, if appropriate. Staff calculated the revenue neutral percent increase to a class's rate revenue by subtracting the overall system average increase of 3.34% (high-point range) from each customer class's required percentage increase to rate revenue to match the revenues Empire should receive from that class to match Empire's cost to serve that class shown in Table 1.

For example, based on Table 1, on a revenue neutral basis, the Residential customer class is providing 4.33% less revenue to Empire than Empire's cost to serve that class. Also, the Commercial Building customer class is providing 4.89% more revenue to Empire than Empire's cost to serve that class. Staff's CCOS study results for all of the customer classes Staff used for Empire are presented in Table 1.

Because a CCOS study is not precise and one of a number of factors the Commission may consider in determining rates, it should be used only as a guide for designing rates. In addition, bill impacts, revenue stability, rate stability, and rate continuity need to be considered. While reducing over-collection from customer classes with negative revenue shift percentages (revenues greater than cost to serve) all the way to zero is appealing, the bill impact on the customer classes with positive revenue shift percentages must be considered.

Staff's recommendations for shifts in the class revenue requirements are based on its study results in this case, Staff's review of Empire's revenue neutral adjustments in its last two general rate increase cases (Case Nos. ER-2010-0130 and ER-2011-0004), and Staff's judgment regarding the impact of revenue shifts on all of Empire's customer classes.

Empire's customers who belong to the residential class and the lighting class are well defined. The remaining customers generally belong to one of five main rate groups based upon their load and cost characteristics. A typical customer in each of the rate groups can be described as follows:

- CB: Electric load is not in excess of 40 KW.
- SH: Average load is not in excess of 40 KW during the summer season and regularly uses electric space-heating equipment for all internal space-heating requirements.

- GP: Available for electric service to any general service customer except those who are conveying electric service received to other whose utilization is purely for residential purposes other than transient or seasonal. The monthly billing demand will be the monthly metered demand or 40 kW, whichever is greater.
- LP: Available for electric service to any general service customer except those who are conveying electric service received to others whose utilization is purely for residential purposes other than transient or seasonal. The monthly billing demand will be the monthly metered demand or 1000 kW, whichever is greater.
- PFM: Available for electric service to any custom feed mill or grain elevator. No new customers will be accepted on this rate.
- TEB: General service total electric service which may include motels, hotels, inns, etc. The monthly facilities demand charge will be the monthly metered demand or 40 kW, whichever is greater.
- SC-P: Available for electric service to Praxair, Inc. The monthly on-peak demand shall be determined during the peak hours but in no event shall the peak demand be less than the lesser of 6000 kW or customers Maximum Firm Demand ("MFD"). Contract has curtailment limits.
- ST: Available for electric service to any general service customer who has signed a service contract with the company. The monthly on-peak demand shall be determined by a suitable demand meter during the peak hours but in no event less than the lesser of 6000 kW or customer's MFD.

The Staff's CCOS study provided the investment and costs associated for Empire to provide service to the Lighting class.

Staff's CCOS study used costs and revenues from Staff's accounting information and other sources as outlined below:

A. <u>Data Sources</u>

Staff's CCOS study utilized the Staff's revenue requirement position as filed on November 30, 2012, through Staff's direct revenue requirement cost-of-service recommendation for Empire's retail cost of service. This data includes:

- Adjusted Missouri investment and cost data by FERC account;
- Annualized, normalized rate revenues;
- Fuel and purchased power costs;
- Other operating and maintenance expenses;

- Depreciation and amortizations; and
- Taxes.

In addition, Staff reviewed Empire's CCOS study from Case No. ER-2011-0004 and workpapers on meters, meter reading, uncollectible accounts, customer premise installations, and customer deposits.

B. Classes and Rate Schedules

Empire currently provides service to its customers in a number of rate groups that are designated for residential or non-residential service and are listed in Table 1 above. The non-residential customer groups are differentiated by voltage level and/or by kilowatt ("kW") demands.

C. Functions

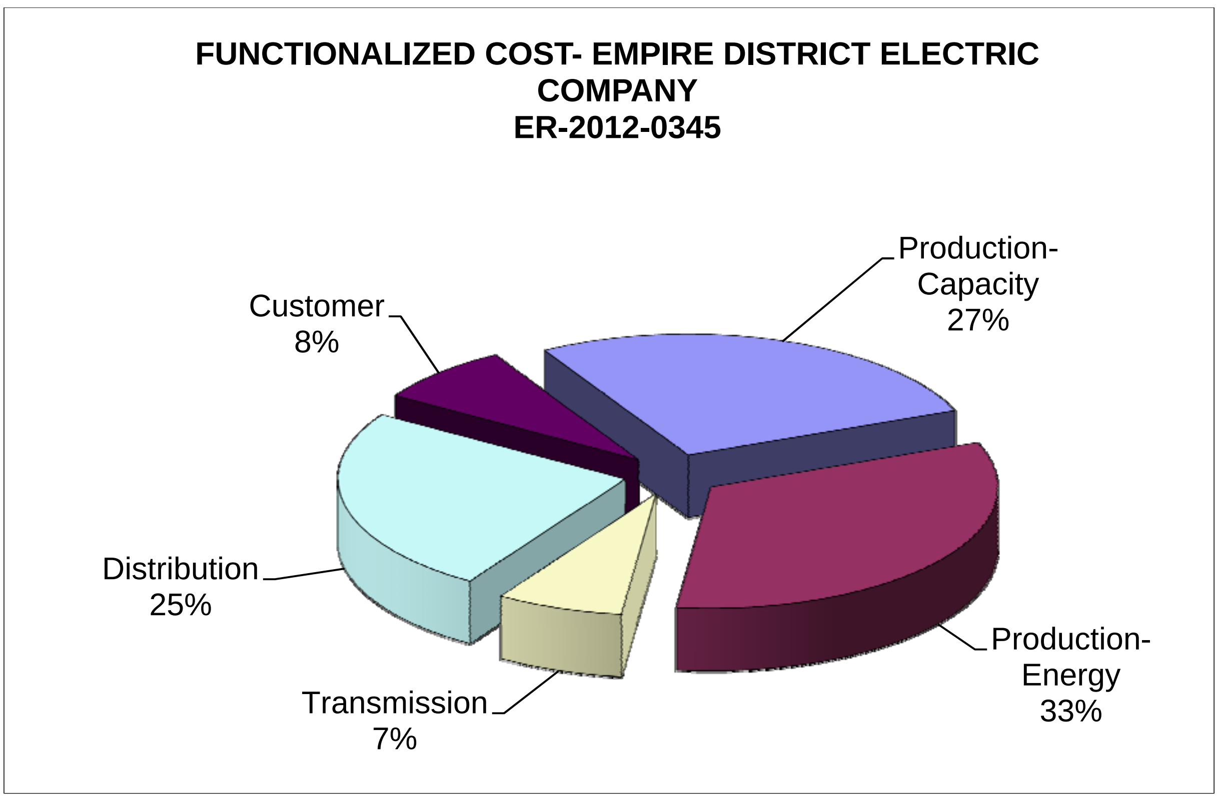
The major functional cost categories Staff used in its CCOS study are Production, Transmission, Distribution, and Customer. Within the Production Function, a distinction was made between "Production-Capacity" and "Production-Energy." Production-Capacity costs are those costs directly related to the capital cost of generation. They are allocated by designated base usage, intermediate usage, and peak usage. The designated usage for each group (base, intermediate, and peak) is allocated to each customer class based on usage characteristics of the customers in the class.

Energy-related costs are those costs related directly to the customer's consumption of electrical energy (kilowatt-hours) and consist primarily of fuel, fuel handling, and the energy portion of net interchange power costs. The other functions that costs are classified by are distribution, transmission and customer costs.

The "Production Function" (combination of Production-Capacity and Production-Energy) is the single largest cost component, and represents 60% of the total cost. The

"Distribution Function," at 25% of the total cost, is the second largest contributor to total cost, and includes substations, overhead and underground lines, and line transformers, as well as the costs to operate and maintain this equipment. "Customer Services," at 8%, and "Transmission," at 7%, round out the total cost. Schedule MSS-1 provides Staff's functionalized CCOS with each class's revenue deficiency required to exactly match that customer class's rate revenues with Empire's cost to serve that class. Schedule MSS-2 provides a detailed description of each external allocation factor Staff used to allocate each function in its CCOS study.

Table 2



D. <u>Allocation of Production Costs</u>

"Production demand," refers to the rate at which electric energy is delivered to the system to match the energy requirements of its customers, either at an instant in-time or averaged over a designated interval of time. In order to develop a fully comprehensive cost-of-service analysis to identify the revenue requirements for Empire, all of Empire's production costs for plant investment and the production expenses appearing on its income statement must be appropriately allocated by a production-capacity (fixed) or a production-energy (variable) allocator. Empire's generation facilities, used to produce electricity to Empire retail customers in Missouri, are predominantly considered fixed assets. The costs and investments of these assets are apportioned to the rate classes on the basis of production-capacity allocator. Both the demand and energy characteristics of Empire's load are important determinants of production investment and costs, since Empire must produce or purchase output enough to meet both periods of normal-use and intermittent peak-use throughout the year. The costs of generation facilities are directly related to a utility's generation capacity, which is determined through the utility's system planning, where many factors including load factor and peak demand are considered, and thus are classified as capacity-related.

Staff allocated Production-Energy fuel costs on annualized kWh usage at generation. Fuel expenses and purchased power costs are directly related to the amount of electricity sold, and thus classified as energy-related.

Staff allocated Production-Capacity costs based on a modified Base-Intermediate-Peak ("BIP") method. The modified BIP method is based on recognition that capacity requirements are an important determinant of production-capacity investment and costs. With the modified BIP method, the utility company's required investments, and the ongoing expense of providing service are allocated based on:

1. A base component consisting of the annual energy attributable to a given customer class; this portion is weighted by the system load factor;

2. An intermediate component consisting of the average 12 Non-Coincident Peak ("NCP[1]") of demand for electricity for a given class minus the base component previously allocated; and

3. A peaking component consisting of the average 3 NCP[2] component of demand for electricity less the base and intermediate components previously allocated.

The BIP method is described in the NARUC ELECTRIC UTILITY COST ALLOCATION MANUAL ("NARUC Manual").[3] The NARUC Manual[4] in Part IV, C, Section 2 describes the BIP method as a time-differentiated method that assigns production plant costs to three rating periods (1) peak hours, (2) secondary peak, or intermediate hours, and (3) base-loading hours. Generally, base-load units have high capital costs, generally take five-to-ten years to build, and have low, constant running costs. Because of this, these units run almost continuously, except during periods of maintenance. Because base-load units operate regardless of peak requirements, they are appropriately classified as energy-related.[5] Intermediate units, those with capital costs and operating characteristics between those of base-load units and peaking units, serve a dual purpose in that they are partially energy-related and partially-demand related.[6] Peaking units have low capital costs, are relatively quick to build—typically twelve to eighteen months, but are more costly to run. It is typically most cost-effective to only run these units for the few hours of the year when the utility's system load is the highest. The output of peaking units is used to follow the energy requirements of the system on a real-time basis.

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[1] 12 NCP is each month's maximum peak demand of each customer class at any time during the months of January through December.
[2] 3 NCP is each month's maximum peak demand of each customer class during June, July, and August.
[3] Published January 1992.
[4] Schedule MSS-4 details the BIP method as described in the NARUC Manual.
[5] **Energy-related**: Energy-related costs are those costs related directly to the customer's consumption of electrical energy (kilowatt-hours) and consist primarily of fuel, fuel handling, and the energy portion of net interchange power costs.
[6] **Demand-related:** Demand-related costs are rate base investment and related operating and maintenance expenses associated with facilities necessary to supply a customer's service requirements (kW) during periods of maximum, or peak, levels of power consumption.

Empire operates and maintains generating units that are required to provide both capacity and energy for its customers throughout the year. Prudency requires that Empire operate and maintain these units in a manner that minimizes the overall cost for it to produce safe and reliable electricity for its customers through a mix of generating units that best fits the load on Empire's system, both instantaneously and over time.

The modified BIP method Staff used to allocate production-capacity costs recognizes that generation is built to meet both peak demands and energy usage. The basic components of the modified BIP method are:

1. A portion of the total production-capacity costs is allocated to each customer class based upon that class's contribution to annual energy. This portion is classified as the base peak portion. This portion is weighted by the system load factor;

2. A portion of the total production-capacity costs is allocated to each customer class based upon that class's contribution to intermediate peak demand. Because for each class the portion allocated to it includes the base portion allocated to the class, the base portion allocated to the class is subtracted; and

3. A portion of the total costs allocated to each class based upon each class's contribution to the peak demand. Because for each class the portion allocated to it includes both the base portion and the intermediate portion allocated to it, the base and intermediate portions allocated to the class is subtracted.

In the modified BIP method, the base allocator (the "B" portion in the modified BIP) is calculated on each class's annual kWh usage at generation in the update period and weighted by the system load factor. The intermediate piece (the "I" in the modified BIP) involves using the average of the 12 Non-Coincident Peaks (NCP) for the intermediate piece. The NCP demand is the maximum monthly peak demand of each customer class at any time during the study period, and it may or may not fall on the same hour as the system peak for that month. The intermediate portion is determined by the intermediate peak less the base portion already allocated to the various classes. The final step is to determine the peak portion (the "P" in the modified BIP) for allocation to the various classes. A listing of monthly peak loads, Table 3 below, helps to define the twelve months in terms of a peak season and a non-peak season. Empire is a dual-peaking utility with significant peaks in both winter and summer as compared to its shoulder months. Empire's highest monthly coincident peaks occurred in the summer season for 2008, 2009, 2011, and 2012, and in the winter season in 2010.

Table 3

Coincident System Peak @ Generation kW - Total Company					
Month	2008	2009	2010	2011	2012
January	1,043,000	1,082,000	1,199,000	1,145,000	955,000
February	988,000	993,000	1,013,000	1,153,000	892,000
March	891,000	933,000	880,000	792,000	728,000
April	778,000	788,000	628,000	715,000	735,000
May	815,000	733,000	868,000	834,000	914,000
June	979,000	1,085,000	1,093,000	1,072,000	1,093,000
July	1,083,000	1,005,000	1,085,000	1,145,000	1,136,000
August	1,152,000	1,028,000	1,156,000	1,198,000	1,142,000
September	897,000	813,000	973,000	1,110,000	1,071,000
October	769,700	636,000	666,000	671,000	
November	875,000	743,000	803,000	834,000	
December	1,100,000	1,060,000	1,013,000	915,000	

The peak portion is allocated to the various classes based on each class's share of the summer peak, based on the monthly peaks of June, July, and August less the base and intermediate portions already allocated to the various classes. Staff used the three summer months during the test year for calculating the production–capacity cost allocator, since the three summer peaks are within approximately 94% of Empire's system peak.

The modified BIP method takes into consideration the differences in the capacity/energy cost trade-off that exists across a company's generation mix. The modified BIP methodology gives weight to both considerations. It does so by considering energy in the base component through the allocation of base usage to all classes, and by considering capacity in the allocation of intermediate and peak components. For these reasons, Staff recommends using the modified BIP method for production investment and for production costs for Empire. Staff explains the modified BIP method further, and addresses other production allocation methods from the NARUC Manual, beginning on page 12, in the attached Schedule MSS-6.

I will describe how with regard to Production-Capacity allocator, Staff used the non-coincidental peak ("NCP") information to allocate production-capacity investment and expense accounts instead of using a coincidental peak ("CP") method for Empire. In a lot of cases described by NARUC, the NCP and CP are common allocation methods for allocating production-capacity costs. While CCOS is very analytic, it is also an art. There is no "right" answer. However, there are reasonable and unreasonable answers.

Two major factors associated with generation capacity planning prompted the use of the NCP demand cost allocation in Staff's modified BIP methodology. The type of capacity (base, intermediate or peaking facilities) which the company adds to its generation fleet is not dictated by maximum customer demand alone, but also by annual energy or kilowatt-hours ("kWh"). A cost allocation methodology that gives weight to both class peak demands and class energy consumption is a realistic and reliable means giving weight to both considerations. The modified BIP method gives weight to both of these considerations, the kWh in the year divided by 8,760 hours in the year in the base component and the excess demands of each class in the intermediate component (12 NCP less base) and peak periods (usually summer months 3 NCP less base and intermediate component already allocated).

One concern with utilizing a CP-based allocation factor is that a particular rate class or parts of a rate class are found to be prominently or completely off-peak in nature. For example, over-reliance on the CP information may result in free ridership for parts of the lighting class and other classes. Free ridership is when service rendered completely off-peak or not at the system peak time is not assigned any responsibility for capacity cost. Outdoor lighting could avoid some of the demand cost assignment as system peaks generally occur during daylight hours. Another example of free ridership is when a utility has demand reducing provisions in its tariff (interruptible service or MPower programs) where a utility may control its peaking dates and times. To alleviate any concern of free ridership or irrational CP allocations, Staff uses NCP information. Another concern with utilizing a CP-based factor is that Empire's "tariff provision" allows Empire the flexibility to implement demand reductions during time of system peaks or for operational and economic reasons. These provisions are contained in Empire's Tariff:

Section 2 Sheet Nos. 9 – 9b Special Transmission Service Contact: Praxair (1 customer)
Section 4 Sheet Nos. 4 – 4e Interruptible Service (3 customers)

These provisions allow Empire to control (request) demand reductions during time of system peaks. These demand reductions may alter the date and time of system peaks and alter the demand production-capacity allocator for certain classes. This could result in the production-capacity allocator being allocated in an irrational manner for certain classes if CP-based information is used. Schedule MSS-5 outlines CP and NCP information for Empire by class. Also, Schedule MSS-5 outlines that Empire interrupted the load of Praxair during the system peak occurring in August.

Additionally, the rates for various classes include time differentiated rates such as seasonal and time-of-use rates. Staff's consistent position has been that the allocation of costs among retail classes should provide a reasonable basis for setting time or seasonal differentiated rates. The modified BIP allocation method using NCP information provides a reasonable method of cost allocation to be used in determining time and seasonal differentiated rates. Staff uses NCP information instead of CP information to alleviate any of the concerns expressed above and to allocate seasonal rate differences (summer v. winter) for rate classes.

Staff used the class modified BIP allocation factors it developed to allocate Empire's investment in fixed production plant and depreciation reserve accounts. The approach of using the same allocators for allocating investments and costs to each class of customer is referred to as "expenses follow plant." Production plant expenses are associated with maintaining and operating the production plant; therefore, it is appropriate to use the same allocator for allocating both plant investment and plant expense.

E. Allocation of Transmission Costs

A transmission system moves electricity, at a very high voltage, from generating plants over long distances to local service areas. Transmission cost consists of costs for high voltage lines and labor to operate and maintain these facilities. Empire's transmission investment and transmission costs comprise approximately 7% of the functionalized investment and costs Staff allocated to the customer classes. Empire's transmission system consists of highly integrated bulk power supply facilities and high voltage power lines that convert voltages for transporting power over other transmission or distribution lines and systems. Staff allocated transmission investment and costs to the customer classes based on the class loads at the time of the 12 monthly NCP, on a 12 NCP basis. Staff recommends the 12 NCP allocation method for this purpose because, by including periods of normal use and intermittent peak use throughout all 12 months of the year, it takes into account the needs for a transmission system that is designed both to transmit electricity during both peak loads and also to transmit electricity throughout the year.

F. <u>Allocation of Distribution Costs</u>

The distribution system converts high voltage power from the transmission system into lower primary voltage and delivers it to large industrial complexes, and further converts it into even lower secondary voltage power which can be delivered into homes for lights and appliances. Distribution is the final link in the chain built to deliver electricity to the customers' homes or businesses. A utility's distribution plant includes distribution substations, poles, wires, transformers, and meters, as well as service and labor expenses incurred for the operation and maintenance of these distribution facilities. Voltage level is a factor that Staff considered when allocating distribution costs to customer classes. A customer's use or non-use of specific utility-owned equipment is directly related to the voltage level needs of the customer. All residential customers are served at secondary voltage; non-residential customers are served at secondary, primary, substation, or transmission level voltages. Only those customers in customer classes served at substation voltage, or below were included in the calculation of the allocation factor for distribution substations. Staff used the annual class peak of these customer classes to allocate substation costs.

Staff allocated the costs of the primary distribution facilities on the basis of each customer class's annual peak demand measured at primary voltage. All customers, except those served at transmission level, (i.e., primary and secondary customers) were included in the calculation of the primary distribution allocation factor, so that distribution primary costs were allocated only to those customers that used these facilities. Staff used the annual customer class peak to allocate primary costs.

Load diversity is important in allocating demand-related distribution costs because the greater the diversity among customers within a class or among classes, the smaller the total capacity (and total cost) of the equipment required for the utility to meet those customers' needs. Load diversity exists when the peak demands of customers do not occur at the same time. The spread of individual customer peaks over time within a customer class reflects the diversity of the class load. Therefore, when allocating costs of demand-related distribution costs that are shared by groups of customers, it is important to choose a measure of demand that corresponds to the proper level of diversity. The following table summarizes the type of demands Staff used for allocating the demand-related portions of the various distribution function categories.

Table 4
Allocation of Demand Related Distribution Facilities

Functional Category	**Demand Measure**	**Amount of Diversity**
N/A	Coincident Peak	High
Substations	Class Peak	Moderate to High
Primary	Class Peak	Moderate to High
OH/UG Conduits/Conductors	Diversified Peak	Low to Moderate
Line Transformers	Diversified Peak	Low to Moderate

Coincident peak demand is "the demand of each customer class and each customer at the hour when the overall system peak occurs." Coincident peak demand reflects the maximum amount of diversity, because most customer classes are not at their individual class peaks at the time of the coincident peak. Class peak demand is "the maximum hourly demand of all customers within a specific class, often does not occur at the same hour, i.e., does not coincide with, the system peak." Although, not all customers peak at the same time (due to intra-class diversity), to achieve the class peak a significant percentage of the customers in the class will be at or near their peak. Therefore, class peak demand will have less diversity than the class' load at time of system peak.

Diversified demand is the weighted average of the class's customer maximum demand and its annual maximum class peak demand. As constructed, diversified demand has less diversity than the class peak, but more diversity than the customer maximum demand. Customer maximum demand has no diversity. It is defined as the sum of the annual peak demands of each customer, whenever it occurs. If there is no sharing of equipment, there is no diversity.

Staff recommends allocating the costs of distribution secondary and line transformers on the basis of each class's annual peak demand and on customer maximum demands. Only secondary customers served at the secondary voltage level were included in the calculation of the allocation factor, so that distribution secondary costs were allocated only to those customers that use these facilities.

Empire conducted special studies to split the cost of poles, towers, fixtures; and overhead ("OH") and underground ("UG") distribution lines between primary- and secondary-related in its previous electric case (ER-2011-0004). Rather than independently conducting its own studies, Staff reviewed Empire's studies and, finding them reliable, chose to rely on them in this case since the data had not changed significantly from Empire's 2011 case.

Staff recommends allocating meter costs using the same allocator that Empire's used to allocate meter costs in Case No. ER-2011-0004. This allocator is based on an Empire study that weights the meter investment by class, and by the cost of the meter used to serve that class.

G. Allocation of Customer Service Costs

Customer costs include labor expenses incurred for billing and customer services. Customer-related costs are costs necessary to make electric service available to the customer, regardless of the electric service utilized. Examples of such costs include meter reading, billing, postage, customer accounting, and customer service expenses.

Staff reviewed how Empire developed its allocators for allocating meter reading costs, uncollectible accounts, and for allocating customer deposits. These three allocators are derived using Empire's studies from Case No. ER-2011-0004 that directly assign the costs of meter reading, uncollectible accounts, and customer deposits to the customer classes. The allocators are the fraction of total costs of meter reading, uncollectible accounts and customer deposits assigned to each class, respectively. Staff has reviewed Empire's methods of allocating these costs between classes in Case No. ER-2011-0004 (Empire's last rate increase case) and has concluded they are reasonable. Staff used these allocators and recommends the Commission rely on them as well.

H. Revenues

Operating revenues consist of (1) the revenue that the utility collects from the sale of electricity to Missouri retail customers ("rate revenues"), and (2) the revenue the utility receives for providing other services ("other revenues"). Rate Revenues are also used in developing Staff's rate design recommendation and will be used to develop the rate schedules required to implement the Commission's ordered revenue requirement and rate design for

Empire in this case. The normalized and annualized class rate revenues in Staff's COS Report filed November 30, 2012, totaling $403.5 million were used in Staff's CCOS Study.

Other Electric Revenues of $7.2 million were also allocated to the rate classes using Staff's production-energy and other cost allocators. Other operating revenue includes forfeited discounts, reconnect charges, rent from electric property, miscellaneous electric revenues, SO2 allowances and renewable energy credits.

I. Allocation of Taxes

Taxes consist of real estate and property taxes, payroll tax expenses and income taxes. Real estate and property tax expenses are directly related to Empire's original cost investment in plant, so these expenses are allocated to customer classes on the basis of the sum of the previously allocated production, transmission, distribution and general plant investment.

Payroll tax expenses are directly related to Empire's payroll expenses, so these expenses are allocated to customer classes on the basis of previously allocated payroll expenses.

Staff calculated income taxes separately for each customer class. Each calculation recognizes the appropriate income tax deductions for each class, and calculates the income tax obligation of each customer class as a function of its taxable income. This has the effect of allocating income taxes based on class earnings.

J. Allocation of Energy Efficiency Costs

On February 28, 2012, Empire filed an application seeking approval of its Missouri Energy Efficiency Investment Act ("MEEIA") plan and for authority to establish a Demand Side Management Mechanism tracker, but on July 5, 2012, withdrew it. However, from 2005 to date, Empire incurred energy efficiency program costs, which it is including in this case in its rate base. Empire's existing DSM programs are the result of an agreement reached in Empire's Experimental Regulatory Plan proceeding, Case No. EO-2005-0263. The existing programs and costs have also been part of Empire's last four (4) general rate cases in Missouri, Case Nos. ER-2006-0315, ER-2008-0093, ER-2010-0130, and ER-2011-0004. Staff allocated these energy efficiency program costs to the residential and non-residential classes (commercial and industrial rate classes), excluding lighting, based on its energy allocator less estimated opt-out customers. Staff recommends that there be a separate DSM cost recovery rate on each rate schedule along with another rate to reflect either: 1) rate including the DSM cost recovery rate (applied to those who have not opted out of DSM), or 2) rate excluding the DSM cost recovery rate (applied to those who opted out of DSM).

Staff Experts: Michael S. Scheperle and Robin Kliethermes

IV. Rate Design

Staff's rate design objectives in this case are to:

- Provide the Commission with a rate design recommendation based on each customer class's relative cost-of-service responsibility.
- Provide methods to implement in rates any Commission-ordered overall change in customer revenue responsibility.
- Retain, to the extent possible, existing rate schedules, rate structures, and important features of the current rate design that reduce the number of customers that switch rates looking for the lowest bill, and mitigate the potential for rate shock.

Staff's rate design recommendations in this case are:

1. Adjustments to class revenue responsibilities made first on a company-wide revenue neutral basis to the residential class, commercial building class and general power class. The Empire residential class should receive a positive 0.5% adjustment. The Empire commercial building class and general power class should receive a negative adjustment of approximately 0.82%. All other classes should receive the system average increase (commercial space heating, special transmission service contract: Praxair, total electric building, feed mill and grain elevator, large power, lighting, and miscellaneous).

2. After having made the recommended revenue neutral adjustments above, any overall change in revenues the Commission orders should be applied on an equal percentage basis to all classes. Staff further recommends that an additional constraint (revenue requirement after true-up) be placed on which class revenues are moved towards class cost-of-service to ensure that no class receives an overall reduction in its rate revenues while another customer class receives an overall increase in its rate revenues.

3. That the residential customer charge be increased to $13.25.

4. That the energy charges for the residential group be increased uniformly, after making the adjustments described in 1, 2, and 3 above.

5. That the charges for the CB, SH, GP, SC-P, TEB, PFM, and LP be increased uniformly, after making the adjustments described in 1 and 2 above.

6. That the lighting charges be increased uniformly after making the adjustments described in 1 and 2 above.

7. Staff recommends that there be a separate DSM cost recovery rate on each rate schedule along with another rate to reflect either: 1) rate including the DSM cost recovery rate (applied to those who have not opted out of DSM), or 2) rate excluding the DSM cost recovery rate (applied to those who opted out of DSM).

Empire has three active lighting service classifications and one miscellaneous service classification 1) Municipal Street Lighting Service Schedule - SPL; 2) Private Lighting Service Schedule - PL; 3) Special Lighting Service Schedule – LS; and 4) Miscellaneous Service Schedule - MS. Staff combined these lighting and miscellaneous service classifications in its CCOS study.

Schedule MSS-3 shows that Empire's residential customer charge is the highest of the five electric utility tariffs in the state. The results of Staff's CCOS study calculate that residential customer costs are $16.63. Staff recommends increasing Empire's residential customer charge by $0.73, from $12.52 to $13.25 after considering and taking into account Staff's revenue-neutral rate increase recommendation for the residential class.

Current Rate Schedules

Empire's charges are determined by each customer's usage and the (per unit) rates that are applied to that usage. The rate schedules should continue to reflect any cost difference associated with service at different voltage levels (i.e., losses and facilities ownership by customers).

The residential rate schedule consists of the following elements:

- Regular Rate Schedule
- Residential Time of Day rate schedule
- Customer Charge
- Energy Charge – per kWh per season

The customers who belong to the residential class and the lighting classes are well defined. The remaining customers generally belong to one of eight main rate groups based upon their load and cost characteristics. A typical customer in each of the other rate groups can be described as follows:

- Commercial Building Service Schedule CB: Electric load is not in excess of 40kW.
- Small Heating service: Average load is not in excess of 40kW during the summer season and regularly uses electric space-heating equipment for all internal space-heating requirements.
- General Power Service Schedule GP: Available for electric service to any general service customer except those who are conveying electric service received to other whose utilization is purely for residential purposes other than transient or seasonal. The monthly billing demand will be the monthly metered demand or 40 kW, whichever is greater.
- Large Power Service Schedule LP: Available for service to any general service customer except those who are conveying electric service to others whose utilization is purely for residential purposes other than transient or seasonal. The monthly billing demand will be the monthly metered demand or 1000kW, whichever is greater.
- Feed Mill and Grain Elevator Service Schedule PFM: Available for electric service to any customer feed mill or grain elevator.
- Total Electric Building Service Schedule TEB: Available to any general service customers on the lines of Empire for total electric service except those customers who

are conveying electric service to others whose utilization of the same is for residential purposes other than transient or seasonal. The monthly billing demand will be the monthly metered demand or 40 kW, whichever is greater.

- Special Transmission Service Contract: Praxair Schedule SC-P: Schedule is available for electric service to Praxair, Inc. In no event shall the Peak demand be lesser of 6000 kW or customer's MFD for Customers that have contracted interruptible capacity as specified in the contract or any future amendments thereto.
- Special Transmission Service Schedule ST: Schedule is available for electric service to any general service customer who has signed a service contract with the Empire.

For its CCOS study, Staff broke the above rate groups into separate rate classes. Staff's CCOS study provided the investment and costs associated for Empire to provide service to the Lighting and Miscellaneous class (Municipal, Private, Special, Miscellaneous).

Staff Expert: Michael S. Scheperle

V. Loss Study

A. <u>Fuel Adjustment Clause Voltage Adjustment Factors</u>

Rule 4 CSR 240-20.090(9) requires an electric utility that wants to continue to utilize its Rate Adjustment Mechanism ("RAM") to conduct a jurisdictional system loss study on the losses incurred from the delivery of electricity. The utility is to perform such a study at least every four years after the Commission's initial granting of a fuel adjustment clause ("FAC"), and a loss study is to be completed within four years of the initiation of any general electric rate case in which the utility requests continuation of its FAC.[7] Empire failed to file a Loss Study at the start of this general rate case, however, Empire did provide a Loss Study in response to Staff DR 208 on December 7, 2012—five months after Empire filed its rate case.

[7] 4 CSR 240-20.090(9) reads as follows: "Rate Design of the RAM. The design of the RAM rates shall reflect differences in losses incurred in the delivery of electricity at different voltage levels for the electric utility's different rate classes. Therefore, the electric utility shall conduct a Missouri jurisdictional system loss study within twenty-four (24) months prior to the general rate proceeding in which it requests its initial RAM. The electric utility shall conduct a Missouri jurisdictional loss study no less often than every four (4) years thereafter, on a schedule that permits the study to be used in the general rate proceeding necessary for the electric utility to continue to utilize a RAM."

The Empire 2011 Analysis of System Losses ("Loss Study") was performed by Management Applications Consulting, Inc. and is the most current loss study for Empire's electric system. The Loss Study is dated December 2012 and contains system loss data for calendar year 2011. Because Staff just received the Loss Study, it has not been able to conduct a thorough review of the Lost Study. However, for this filing, Staff used the information from the Summary of Losses found in Appendix B of the Loss Study to develop the FAC voltage adjustment factors below.

The voltage adjustment factors account for the energy losses incurred in the transmission and distribution of energy from the generator to the customer. These factors are used in calculations to adjust the fuel adjustment rates ("FAR") in the Company's FAC to the applicable individual voltage service classification. Incorrect loss studies will not prevent Empire from ultimately billing the difference between actual and base net energy costs, since the FAC requires a true-up. However, if the actual cost equaled the net base energy cost, using losses that are too low would result in a positive true-up, because Empire would have been under-billing customers. Likewise, using losses that are too high would result in Empire billing the customers too much, so the true-up would be negative. If the total losses are accurate, but the primary/secondary split is inaccurate, it would result in one of the groups of customers paying more than the cost they caused.

Table 1 provides Staff's preliminary new FAC voltage adjustment factors for primary and above and for secondary voltage levels.

Table 1: Empire FAC		
Voltage Adjustment Factors	Voltage Level	
	Primary	Secondary
Current Tariff	1.0502	1.0686
Proposed	**1.0466**	**1.0662**
Change	(0.0036)	(0.0024)

Staff will continue its review of the Loss Study and update its recommended voltage adjustment factors, if necessary, in its rebuttal and/or surrebuttal testimony filings.

Staff Expert: David Roos

B. Current Treatment of Voltage Level in Empire's Rate Schedules

Empire provides service to demand-metered Missouri commercial and industrial customers under three general application rate schedules:

- General Power-Schedule GP
- Large Power-Schedule LP
- Special Transmission Service-Schedule STS

Each of these rate schedules is available to customers within a certain maximum demand and load factor (constancy of load over time), and certain voltage level (secondary, primary, transmission) characteristics. However, none of these characteristics are mandatory requirements; each commercial or industrial customer can choose to take service under the provisions of any general application rate schedule. Voltage level, in particular, does not determine a customer's eligibility for service under any specific rate schedule, even those with restricted availability, since each rate schedule contains provisions to treat customers with non-standard voltage service.

In addition to the three general application rate schedules, Empire offers service to customers on two rate schedules with restricted availability:

- Total Electric Buildings-Schedule TEB
- Special Contract-Praxair-Schedule SC-P

TEB is the companion rate schedule to GP that is only available to "all-electric" customers. SC-Praxair is a companion rate schedule to STS that is only available to Praxair.

The table below summarizes the voltage options for current rate schedules:

Rate Schedule	Type of Rate Schedule	Standard Delivery & Metering Voltage	Non-Standard Delivery Voltages	Non-Standard Metering Voltages
General Power (GP)	General Application	Secondary	Primary	Primary
Total Electric Buildings (TEB)	Restricted Availability	Secondary	Primary	Primary
Large Power (LP)	General Application	Primary	Secondary, Transmission	Secondary, Transmission
Special Contract – Praxair (SC-P)	Restricted Availability	Transmission	Transmission	Primary Substation
Special Transmission Service (STS)	General Application	Transmission	Transmission	Primary Substation

This table highlights the customer options for metered voltage and delivery voltage. Current rate tariff sheets describe the metered voltage options in the Metering Adjustment Section, and the delivery voltage options are described in the Transformer Ownership Section.

Staff Expert: David Roos

C. Proposed Metering Adjustments to Reflect Updated Loss Study

When a customer's electric service is metered at a voltage level other than the standard rate schedule voltage level, an adjustment is made to the customer's metered demand (kilowatts) and energy (kilowatt-hours) prior to billing. Staff is proposing in this case new meter adjustment factors in Empire's rate schedules to reflect the results of Empire's Loss Study. The new metering adjustment factors in the rate schedules allow the losses embedded in permanent rates to be correct and consistent with the losses embedded in the FAC proposed base factors ("BF"). The updated metering adjustment factors are preliminary and Staff will continue its review of the Loss Study and update the metering adjustment factors, if necessary, in its rebuttal and/or surrebuttal testimony filings. Staff's preliminary metering adjustment factors are summarized below:

Rate Schedules	Voltage Level From:	Voltage Level To:	Proposed Factor
General Power	Primary	Secondary	0.9817
Large Power	Secondary	Primary	1.0187
Large Power	Transmission	Primary	0.9778
Special Transmission	Primary Substation	Transmission	1.008

Staff Expert: David Roos

VI. Fuel Adjustment Clause Tariff Sheets

In its COS Report in this case, Staff provided its analysis of and recommendations for the following issues which have an impact on Empire's FAC tariff sheets:

1. Change the sharing mechanism from 95% returned/recovered from the customers and 5% kept/absorbed by Empire to 85% returned/recovered from the customers and 15% kept/absorbed by Empire to provide Empire with a greater incentive to keep its fuel and purchased power costs down;

2. Standardize the terminology in Empire's FAC tariff sheets to be consistent with the changes Staff is recommending, when appropriate, to the FAC tariff sheets of the three investor-owned electric utilities with FACs.

Staff recommends the Commission approve the exemplar FAC tariff sheets provided in Schedule MJB-2.

Staff recommends the Commission change the net base energy cost per kWh rate to the below rate based upon the following information in Staff's COS Report in this case: 1) base energy costs (fuel and purchased power costs less emission allowance revenues, off-system sales revenues and renewable energy credits revenues); 2) Staff's adjustments to test year expenses related to base energy costs; and 3) normalized net system inputs. Staff calculated the net base energy cost per kWh rate before voltage adjustments to be $0.03223 per kWh. Staff will update the net base energy cost per kWh before voltage adjustment rates for Empire as part of the test year true-up in this case.

There are certain items of cost and/or revenue included in specified accounts used to calculate the net base energy cost for the above net base energy cost per kWh rate. At the time of filing this testimony, Staff was and still continues to be in discussions with Empire to determine which Federal Energy Regulatory Commission (FERC) accounts and subaccounts should flow through the FAC and which ones should not. As an example, in Empire's response to Staff data request number 0163, Empire lists all the FERC accounts that flow through the FAC (See Schedule MJB-4). Some of the FERC accounts include FAS 133 effective and ineffective gains and losses related to derivatives. Staff wants to gain a better understanding of what those costs are and why Empire believes they should flow through Empire's FAC before Staff recommends to the Commission that these costs be flowed through the FAC.

Changes to Terminology in Empire's FAC Tariff Sheets

The Commission, Staff, the electric utilities and other parties have been refining FACs, and the tariff sheets that implement them, since the Commission first authorized Aquila, Inc., n/k/a KCP&L Greater Missouri Operations Company ("GMO") to use a FAC in Case No. ER-2007-0004. While each utility's FAC operates in a similar fashion and the FAC tariff sheets are similar, each utility has a unique FAC and unique FAC tariff sheets with unique acronyms and definitions. Different nomenclatures for the same thing are used across the utilities, and sometimes even within a single utility's FAC tariff sheets. On Page 144, Line 14 through Line 19, in the COS Report filed November 30, 2012, Staff provided an example of the various terms that the Missouri electric utilities use for the dollar amount of the adjustment. Another example is the terms used to identify the FAC dollar per kWh charge before voltage adjustment rate of each utility. Union Electric Company d/b/a Ameren Missouri refers to it as “FPA rate,” “FPA_c rate” or just “FPA_c.” GMO refers to it as a “Cost Adjustment Factor” or “CAF,” “Current annual CAF,” “Annual CAF,” and “Fourth Interim Total.” Empire refers to it as a “Cost Adjustment Factor” or “CAF.” It is Staff’s proposal that the FAC dollar per kWh charge before voltage adjustment rate be called the “Fuel Adjustment Rate” or “FAR” consistently in the FAC tariff sheets of all the electric utilities.

Schedule MJB-1 contains a table that lists the terminology and definitions that Staff is proposing be made consistent across the three electric utilities’ FAC tariff sheets. Staff has been working with all of the electric utilities, including Empire, on these proposals to reach a consensus with them on the terminology to be used within the electric utility industry in Missouri. It is not Staff’s desire to change the intent or the meaning of different concepts in each utility’s FAC tariff sheets with these changes, but to help avoid and minimize confusion when discussing the FACs of electric utilities in Missouri. Staff witness Lena M. Mantle made this same recommendation in the current Ameren Missouri general rate case, Case No. ER-2012-0166, and Staff witness Matthew J. Barnes made the same recommendation in KCP&L Greater Missouri Operation Company’s general electric rate case, Case No. ER-2012-0175.

The attached exemplar FAC tariff sheets also include some “clean up” suggestions along with other changes Staff has identified and is recommending. Staff continues to work with Empire to finalize specific language in the tariff sheets including more descriptive language regarding the costs and revenues that flow through Empire’s FAC.

Schedule MJB-2 contains Staff's proposed exemplar tariff sheets for Empire's FAC. Schedule MJB-3 is Staff's redline/strikeout comparison of these exemplar tariff sheets with Empire's currently effective FAC tariff sheets.

Staff Expert: Matthew J. Barnes

VII. Fuel Adjustment Clause Heat Rate and Efficiency Testing

In Staff's COS Report filed on November 30, 2012, Staff stated its intent to file additional testimony on the FAC heat rate testing. Commission Rule 4 CSR 240-3.161(3)(Q) requires that an electric utility shall file specific heat rate testing information as part of its direct testimony in a general rate proceeding and that the tests should be performed in the 24-month period preceding the filing of the general rate proceeding. Company witness Todd W. Tarter filed the results of the most recent heat rate/efficiency tests for the Company's generating units. Staff determined that the results for the Asbury and State Line Combined Cycle (SLCC) unit were based on tests completed in June of 2010, which is the month before the 24 month period required by the rule. The Company provided Staff with new heat rate tests results for Asbury and SLCC on November 30, 2012. Staff has reviewed the summary results of those tests and compared the results with the summary results from the previous general rate proceedings. The heat rate/efficiency testing information for the Asbury and SLCC units appears to be reasonable.

The Company also provided Staff with new heat rate tests results for the Riverton units on November 30, 2012. The previous tests for the Riverton units were performed in July 2010, which is within the 24-month period required by the rule. However, since two of the Riverton units (Riverton 7 & 8) were primarily run on coal in the previous tests but are now exclusively fueled by natural gas, the Company provided new test results for all of the

Riverton units. Riverton 7 & 8 are the units with the most change from previous test results. The results indicate that Riverton 7 & 8 have significant efficiency improvements primarily due to the elimination of coal handling facilities that previously used a significant amount of the station use power. The heat rate/efficiency testing information for the Riverton units appears to be reasonable.

Staff would also note that on page 146, line 21, of Staff's COS Report, the Staff incorrectly identified KCP&L Greater Missouri Operations Company's current rate proceeding as Case No. ER-2012-0356, but the correct case number is Case No. ER-2012-0175.

Staff Expert: Daniel I. Beck

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company of Joplin, Missouri Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company	)))))	Case No. ER-2012-0345

AFFIDAVIT OF MICHAEL S. SCHEPERLE

STATE OF MISSOURI)
) **ss**
COUNTY OF COLE)

Michael S. Scheperle, employee of the Staff of the Missouri Public Service Commission, being of lawful age and after being duly sworn, states that he has participated in the preparation of the accompany Staff Report on pages 1 - 25, and the facts therein are true and correct to the best of his knowledge and belief.

Michael Scheperle
Michael S. Scheperle

Subscribed and sworn to before me this 13th day of December, 2012.

SUSAN L. SUNDERMEYER
Notary Public - Notary Seal
State of Missouri
Commissioned for Callaway County
My Commission Expires: October 03, 2014
Commission Number: 10942086

Susan L. Sundermeyer
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company of Joplin, Missouri Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company	)))))	Case No. ER-2012-0345

AFFIDAVIT OF ROBIN KLIETHERMES

STATE OF MISSOURI)
) **ss**
COUNTY OF COLE)

Robin Kliethermes, employee of the Staff of the Missouri Public Service Commission, being of lawful age and after being duly sworn, states that she has participated in the preparation of the accompany Staff Report on pages 5 — 22, and the facts therein are true and correct to the best of her knowledge and belief.

Robin Kliethermes

Subscribed and sworn to before me this 13th day of December, 2012.

Susan L Sundermeyer
Notary Public

SUSAN L. SUNDERMEYER
Notary Public - Notary Seal
State of Missouri
Commissioned for Callaway County
My Commission Expires: October 03, 2014
Commission Number: 10942086

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company of Joplin, Missouri Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company	)))))	Case No. ER-2012-0345

AFFIDAVIT OF DAVID C. ROOS

STATE OF MISSOURI)
) **ss**
COUNTY OF COLE)

David C. Roos, employee of the Staff of the Missouri Public Service Commission, being of lawful age and after being duly sworn, states that he has participated in the preparation of the accompany Staff Report on pages 25-29, and the facts therein are true and correct to the best of his knowledge and belief.

David C. Roos
David C. Roos

Subscribed and sworn to before me this 13th day of December, 2012.

Susan L Sundermeyer
Notary Public

SUSAN L. SUNDERMEYER
Notary Public - Notary Seal
State of Missouri
Commissioned for Callaway County
My Commission Expires: October 03, 2014
Commission Number: 10942086

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company of Joplin, Missouri Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company	)))))	Case No. ER-2012-0345

AFFIDAVIT OF MATTHEW J. BARNES

STATE OF MISSOURI)
) **ss**
COUNTY OF COLE)

Matthew J. Barnes, employee of the Staff of the Missouri Public Service Commission, being of lawful age and after being duly sworn, states that he has participated in the preparation of the accompany Staff Report on pages 29-32, and the facts therein are true and correct to the best of his knowledge and belief.

Matthew J. Barnes

Matthew J. Barnes

Subscribed and sworn to before me this 13th day of December, 2012.

Susan L. Sundermeyer

Notary Public

SUSAN L. SUNDERMEYER
Notary Public - Notary Seal
State of Missouri
Commissioned for Callaway County
My Commission Expires: October 03, 2014
Commission Number: 10942086

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company of Joplin, Missouri Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company	)))))	Case No. ER-2012-0345

AFFIDAVIT OF DANIEL I. BECK

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

Daniel I. Beck, employee of the Staff of the Missouri Public Service Commission, being of lawful age and after being duly sworn, states that he has participated in the preparation of the accompany Staff Report on pages 32 – 33, and the facts therein are true and correct to the best of his knowledge and belief.

Daniel I Beck

Daniel I. Beck

Subscribed and sworn to before me this 13th day of December, 2012.

Susan L Sundermeyer

Notary Public

SUSAN L. SUNDERMEYER
Notary Public - Notary Seal
State of Missouri
Commissioned for Callaway County
My Commission Expires: October 03, 2014
Commission Number: 10942086

Missouri Public Service Commission
Case No. ER-2012-0345

Functional Category	RES	CB	SH	GP	SC-P	TEB	PFM	LP	MS	SPL	PL	LS	Total
Production - Capacity	$55,549,157	$10,484,344	$2,697,989	$21,324,711	$1,072,565	$9,961,121	$21,635	$13,654,639	$2,178	$694,853	$576,845	$260,708	$116,300,744
Production - Energy	$57,543,846	$10,407,179	$3,134,709	$29,266,741	$2,047,276	$12,490,456	$11,137	$22,096,613	$4,585	$602,056	$486,870	$26,953	$138,118,422
Transmission	$14,647,989	$2,548,282	$774,233	$5,332,607	$295,976	$2,790,313	$5,063	$3,536,480	$591	$205,867	$142,603	$34,544	$30,314,548
Distribution - Demand	$39,096,368	$6,419,940	$2,177,142	$11,884,451	$580	$6,829,327	$13,870	$6,646,274	$1,153	$390,309	$337,326	$178,832	$73,975,573
Distribution - Services	$7,688,377	$1,409,752	$249,851	$226,657	$0	$93,251	$559	$0	$0	$0	$0	$11,627	$9,680,074
Distribution - Meters	$3,255,414	$1,142,428	$202,473	$296,344	$8,128	$160,758	$453	$88,250	$0	$0	$0	$9,422	$5,163,671
Distribution - Customer Installations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,284,288	$0	$1,284,288
Distribution - Lighting	$0	$0	$0	$0	$0	$0	$0	$0	$0	$882,507	$1,194,470	$0	$2,076,977
Customer Deposit	($134,824)	($57,950)	($20,416)	($41,016)	$0	($40,108)	($230)	($1,928)	$0	$0	($954)	($162)	($297,587)
Customer Meter Reading	$1,804,259	$253,856	$44,991	$29,205	$144	$15,843	$1,209	$3,281	$0	$0	$6,253	$2,094	$2,161,134
Other Customer Billing	$6,010,316	$833,758	$145,903	$83,079	$48	$44,963	$335	$1,820	$48	$287	$18,914	$6,991	$7,146,462
Uncollectible Accounts	$1,938,013	$16,475	$4,341	$33,154	$1,376	$15,481	$36	$524	$0	$0	$0	$0	$2,009,397
Customer Services and Information	$2,617,924	$363,161	$63,551	$36,187	$21	$19,585	$146	$793	$21	$125	$8,238	$3,045	$3,112,797
Sales Expenses	$307,659	$42,679	$7,469	$4,253	$2	$2,302	$17	$93	$2	$15	$968	$358	$365,817
Income Tax	$12,693,946	$3,815,758	$750,464	$8,032,254	$238,757	$2,837,311	$4,930	$3,982,365	$2,187	$314,603	$284,729	($78,026)	$32,879,279
Excess Facilities	$148,257	$26,813	$8,076	$53,289	$0	$32,181	$29	$41,330	$0	$0	$0	$0	$309,975
Total CCOS Including Additional Income Tax	$203,166,702	$37,706,476	$10,240,774	$76,561,916	$3,664,873	$35,252,782	$59,191	$50,050,533	$10,764	$3,090,623	$4,340,551	$456,387	$424,601,572
Rate Revenue	$185,477,796	$37,676,461	$9,594,656	$77,976,650	$3,220,490	$33,596,999	$54,703	$48,670,626	$12,896	$2,937,276	$4,188,922	$130,100	$403,537,574
Other Operating Revenue	$3,462,480	$614,909	$173,676	$1,293,152	$411,776	$629,827	$823	$937,208	$903	$29,106	$32,925	$2,548	$7,589,333
Total Revenue	$188,940,275	$38,291,370	$9,768,332	$79,269,802	$3,632,265	$34,226,826	$55,526	$49,607,833	$13,799	$2,966,383	$4,221,847	$132,648	$411,126,907
Revenue Deficiency	$14,226,427	($584,894)	$472,442	($2,707,887)	$32,607	$1,025,956	$3,665	$442,700	($3,035)	$124,241	$118,704	$323,739	$13,474,665
Percent Change	7.67%	-1.55%	4.92%	-3.47%	1.01%	3.05%	6.70%	0.91%	-23.54%	4.23%	2.83%	248.84%	3.34%

Missouri Public Service Commission
Case No. ER-2012-0345
Summary of Functions and Allocation Methods in CCOS Study

Function	Allocation to Rate Schedules
Production Plant and Reserve	
Base	Annual kWh usage @ generation for each rate class
Intermediate	12 NCP remaining less Base
Peak	3 NCP in summer less Base and Intermediate
Transmission Plant and Reserve	12 NCP Average
Distribution Plant and Reserve	
Substations	NCP class demand @ substation
Primary	NCP class demands @ primary
Secondary	NCP class demands and Maximum customer demands
Line Transformers	NCP class demands and Maximum customer demands
Services	Empire study from Case No. ER-2011-0004
Meters	Empire study from Case No. ER-2011-0004
General and Intangible Plant and Reserv	Functional separation of Production, Transmission and Distribution Plant
Other Rate Base	Revenues, Energy, Labor, Plant, O&M, and company studies
Expenses	
Production	
Fuel	Annual kWh usage @ generation for each rate class
Other	Fixed - expenses follow plant
Maintenance	Fixed - expenses follow plant
Transmission	12 NCP Average
Distribution	NCP, Distribution Plant, and company studies
Customer Billing, Services and Sales	Number of customers and company studies
Depreciation and Amortization Expenses	
Production	Base, Intermediate, and Peak component based on Production Plant
Transmission	12 NCP Average
Distribution	Distribution Plant
General and Intangible	Functional separation of Production, Transmission and Distribution Plant
A&G expenses	Labor, plant, and revenues
Taxes, other than Income Taxes	Plant, Labor
Taxes	Earnings of each class

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Customer Charges for Residential Class

Company	Current Residential Customer Charge
AmerenUE (1)	$8.03
Empire District Electric Company (2)	$12.52
Kansas City Power & Light Company (3)	$9.00
KCP&L Greater Missouri Operations Company - L&P (4)	$9.75
KCP&L Greater Missouri Operations Company - MPS (5)	$10.43

(1) Mo. P.S.C. Schedule No. 5 , Sheet No. 28 (Includes Low-Income Pilot Program)
(2) P.S.C. Mo. No. 5, Section 1, Sheet No. 1
(3) P.S.C. Mo. No. 7, Sheet No. 5A
(4) P.S.C. Mo. No. 1, Sheet No. 18
(5) P.S.C. Mo. No. 1, Sheet No. 51

TABLE 4-16

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE 12 CP AND 1/13TH WEIGHTED AVERAGE DEMAND METHOD

Rate	Demand Allocation Factor - 12 CP MW (Percent)	Demand-Related Production Plant Revenue Requirement	Average Demand (Total MWH) Allocation Factor	Energy-Related Production Plant Revenue Requirement	Total Class Production Plant Revenue Requirement
DOM	32.09	314,111,612	30.96	25,259,288	339,370,900
LSMP	38.43	376,184,775	33.87	27,629,934	403,814,709
LP	26.71	261,492,120	31.21	25,455,979	286,948,099
AG&P	2.42	23,723,364	3.22	2,629,450	26,352,815
SL	0.35	3,389,052	0.74	600,426	3,989,478
TOTAL	100.00	978,900,923	100.00	81,575,077	$1,060,476,000

Notes: Using this method, 12/13ths (92.31 percent) of production plant revenue requirement is classified as demand-related and allocated using the 12 CP allocation factor, and 1/13th (7.69 percent) is classified as energy-related and allocated on the basis of total energy consumption or average demand.

Some columns may not add to indicated totals due to rounding.

C. Time-Differentiated Embedded Cost of Service Methods

Time-differentiated cost of service methods allocate production plant costs to baseload and peak hours, and perhaps to intermediate hours. These cost of service methods can also be easily used to allocate production plant costs to classes without specifically identifying allocation to time periods. Methods discussed briefly here include production stacking methods, system planning approaches, the base-intermediate-peak method, the LOLP production cost method, and the probability of dispatch method.

1. Production Stacking Methods

Objective: The cost of service analyst can use production stacking methods to determine the amount of production plant costs to classify as energy-related and to determine appropriate cost allocations to on-peak and off-peak periods. The basic principle of such methods is to identify the configuration of generating plants that would be used to serve some specified base level of load to classify the costs associated with those units as energy-related. The choice of the base level of load is crucial because it determines the amount of production plant cost to classify as energy-related. Various base load level options are available: average annual load, minimum annual load, average off-peak load, and maximum off-peak load.

Implementation: In performing a cost of service study using this approach, the first step is to determine what load level the "production stack" of baseload generating units is to serve. Next, identify the revenue requirements associated with these units. These are classified as energy-related and allocated according to the classes' energy use. If the cost of service study is being used to develop time-differentiated costs and rates, it will be necessary to allocate the production plant costs of the baseload units first to time periods and then to classes based on their energy consumption in the respective time periods. The remaining production plant costs are classified as demand-related and allocated to the classes using a factor appropriate for the given utility.

An example of a production stack cost of service study is presented in Table 4-17. This particular method simply identified the utility's nuclear, coal-fired and hydroelectric generating units as the production stack to be classified as energy-related. The rationale for this approach is that these are truly baseload units. Additionally, the combined capacity of these units (4,920.7 MW) is significantly less than either the utility's average demand (7,880 MW) or its average off-peak demand (7,525.5 MW); thus, to get up to the utility's average off-peak demand would have required adding oil and gas-fired units, which generally are not regarded as baseload units. This method results in 89.72 percent of production plant being classified as energy-related and 10.28 percent as demand-related. The allocation factor and the classes' revenue responsibility are shown in Table 4-17.

2. Base-Intermediate-Peak (BIP) Method

The BIP method is a time-differentiated method that assigns production plant costs to three rating periods: (1) peak hours, (2) secondary peak (intermediate, or shoulder hours) and (3) base loading hours. This method is based on the concept that specific utility system generation resources can be assigned in the cost of service analysis as serving different components of load; i.e., the base, intermediate and peak load components. In the analysis, units are ranked from lowest to highest operating costs. Those with the lower operating costs are assigned to all three periods, those with intermediate running costs are assigned to the intermediate and peak periods, and those with the highest operating costs are assigned to the peak rating period only.

TABLE 4-17

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING A PRODUCTION STACKING METHOD

Rate Class	Demand Allocation Factor - 3 Summer & 3 Winter Peaks (%)	Demand-Related Production Plant Revenue Requirement	Energy Allocation Factor (Total MWH)	Energy-Related Production Plant Revenue Requirement	Total Class Production Plant Revenue Requirement
DOM	36.67	39,976,509	30.96	294,614,229	334,590,738
LSMP	35.50	38,701,011	33.87	322,264,499	360,965,510
LP	25.14	27,406,857	31.21	296,908,356	324,315,213
AG&P	2.22	2,420,176	3.22	30,668,858	33,089,034
SL	0.47	512,380	0.74	7,003,125	7,515,505
TOTAL	100.00	109,016,933	100.00	951,459,067	$1,060,476,000

Note: This allocation method uses the same allocation factors as the equivalent peaker cost method illustrated in Table 4-12. The difference between the two studies is in the proportions of production plant classified as demand- and energy-related. In the method illustrated here, the utility's identified baseload generating units -- its nuclear, coal-fired and hydroelectric generating units -- were classified as energy-related, and the remaining units -- the utility's oil- and gas-fired steam units, its combined cycle units and its combustion turbines -- were classified as demand-related. The result was that 89.72 percent of the utility's production plant revenue requirement was classified as energy-related and allocated on the basis of the classes' energy consumption, and 10.28 percent was classified as demand-related and allocated on the basis of the classes' contributions to the 3 summer and 3 winter peaks.

Some columns may not add to indicated totals due to rounding

There are several methods that may be used for allocating these categorized costs to customer classes. One common allocation method is as follows: (1) peak production plant costs are allocated using an appropriate coincident peak allocation factor; (2) intermediate production plant costs are allocated using an allocator based on the classes' contributions to demand in the intermediate or shoulder period; and (3) base load production plant costs are allocated using the classes' average demands for the base or off-peak rating period.

In a BIP study, production plant costs may be classified as energy-related or demand-related. If the analyst believes that the classes' energy loads or off-peak average demands are the primary determinants of baseload production plant costs, as indicated by the inter-class allocation of these costs, then they should also be classified as energy-related and recovered via an energy charge. Failure to do so -- i.e., classifying production plant costs as demand-related and recovering them through a $/KW demand charge -- will result in a disproportionate assignment of costs to low load factor customers within classes, inconsistent with the basic premise of the method.

3. LOLP Production Cost Method

LOLP is the acronym for loss of load probability, a measure of the expected value of the frequency with which a loss of load due to insufficient generating capacity will occur. Using the LOLP production cost method, hourly LOLP's are calculated and the hours are grouped into on-peak, off-peak and shoulder periods based on the similarity of the LOLP values. Production plant costs are allocated to rating periods according to the relative proportions of LOLP's occurring in each. Production plant costs are then allocated to classes using appropriate allocation factors for each of the three rating periods; i.e., such factors as might be used in a BIP study as discussed above. This method requires detailed analysis of hourly LOLP values and a significant data manipulation effort.

4. Probability of Dispatch Method

The probability of dispatch (POD) method is primarily a tool for analyzing cost of service by time periods. The method requires analyzing an actual or estimated hourly load curve for the utility and identifying the generating units that would normally be used to serve each hourly load. The annual revenue requirement of each generating unit is divided by the number of hours in the year that it operates, and that "per hour cost" is assigned to each hour that it runs. In allocating production plant costs to classes, the total cost for all units for each hour is allocated to the classes according to the KWH use in each hour. The total production plant cost allocated to each class is then obtained by summing the hourly cost over all hours of the year. These costs may then be recovered via an appropriate combination of demand and energy charges. It must be noted that this method has substantial input data and analysis requirements that may make it prohibitively expensive for utilities that do not develop and maintain the required data.

TABLE 4-18

SUMMARY OF PRODUCTION PLANT
COST ALLOCATIONS USING DIFFERENT COST OF SERVICE METHODS

	1 CP METHOD		12 CP METHOD		3 SUMMER & 3 WINTER PEAK METHOD		ALL PEAK HOURS APPROACH		AVERAGE AND EXCESS METHOD	
	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total
DOM	$ 369,461,692	34.84	$ 340,287,579	32.09	$ 388,925,712	36.67	$ 340,747,311	32.13	$ 386,682,685	36,46
LSMP	394,976,787	37.25	407,533,507	38.43	376,433,254	35.50	384,043,376	36.21	369,289,317	34.82
LP	261,159,089	24.63	283,283,130	26.71	266,582,600	25.14	299,737,319	28.26	254,184,071	23.97
AG&P	34,878,432	3.29	25,700,311	2.42	23,555,089	2.22	28,970,743	2.73	41,218,363	3.89
SL	0	0.00	3,671,473	0.35	4,978,544	0.47	6,977,251	0.66	9,101,564	0.86
Total	$1,060,476,000	100.00	$1,060,476,000	100.0	$1,060,476,000	100.00	$1,060,476,000	100.0	$1,060,476,000	100.0

	EQUIVALENT PEAKER COST METHOD		BASE AND PEAK METHOD		1 CP AND AVERAGE DEMAND METHOD		12 CP AND 1/13th AVERAGE DEMAND METHOD		PRODUCTION STACKING METHOD	
Rate Class	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total
DOM	$ 340,657,471	32.12	$ 3350,522,360	33.05	$ 354,381,313	33.42	$ 339,370,900	32.00	$ 334,590,738	31.55
LSMP	362,698,678	34.20	382,505,016	36.07	381,842,722	36.01	403,814,709	38.08	360,965,510	34.04
LP	317,863,510	29.97	293,007,874	27.63	286,764,179	27.04	286,948,099	27.06	324,315,213	30.58
AG&P	32,021,813	3.02	27,868,280	2.63	34,623,156	3.36	26,352,815	2.48	33,089,034	3.12
SL	7,232,529	0.68	6,572,470	0.62	2,864,631	0.27	3,989,478	0.38	7,515,505	0.71
Total	$1,060,476,000	100.00	$1,060,476,000	100.00	$1,060,476,000	100.00	$1,060,476,000	100.00	$1,060,476,000	100.00

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		Coincidental Peak - CP Information (Missour Retail)											
Month	RG	CB	SH	GP	SC-P	TEB	PFM	LP	Misc	SPL	PL	Special	Total
January	469,588	67,736	28,291	132,064	6,820	90,064	74	80,756	16	0	0	0	875,409
February	391,194	59,593	23,000	120,971	6,931	76,099	85	81,430	17	0	0	0	759,320
March	335,932	52,211	20,512	120,778	7,135	72,267	77	79,957	16	0	0	0	688,885
April	189,493	52,849	13,707	129,605	7,869	53,172	29	94,528	17	0	0	0	541,269
May	258,043	63,876	15,441	133,092	7,048	58,618	58	101,094	16	0	0	0	637,286
June	398,479	76,920	19,852	159,726	6,943	71,351	86	103,782	17	0	0	0	837,156
July	433,013	63,659	18,356	155,980	6,727	72,283	70	96,621	16	0	0	0	846,725
August	417,078	85,528	21,727	171,453	74	80,185	51	99,690	16	0	0	0	875,802
September	358,697	57,772	16,008	151,572	6,740	63,430	98	95,091	17	0	0	0	749,425
October	243,415	51,131	12,732	112,581	7,443	69,381	55	80,427	16	0	0	0	577,181
November	286,910	58,921	16,553	122,517	6,925	69,675	40	87,119	17	0	0	0	648,677
December	425,727	62,826	26,087	130,905	6,808	97,256	57	83,862	16	0	0	0	833,544
Total	4,207,569	753,022	232,266	1,641,244	77,463	873,781	780	1,084,357	197	0	0	0	8,870,679
Percent	47.432%	8.489%	2.618%	18.502%	0.873%	9.850%	0.009%	12.224%	0.002%	0.000%	0.000%	0.000%	100.000%

		Non-Coincidental Peak - NCP Information (Missouri Retail)											
Month	RG	CB	SH	GP	SC-P	TEB	PFM	LP	Misc	SPL	PL	Special	Total
January	532,071	74,195	30,241	135,725	8,178	92,433	98	87,999	16	5,702	3,110	405	970,173
February	469,201	63,398	25,057	132,088	8,178	81,876	99	89,282	17	5,711	3,586	161	878,654
March	405,968	59,155	20,512	127,005	8,172	72,267	95	96,395	16	5,698	3,706	206	799,195
April	281,002	59,353	16,183	142,590	8,320	66,351	99	96,890	17	5,735	4,226	607	681,373
May	300,458	70,444	17,107	146,811	8,382	62,594	117	104,574	16	5,772	4,561	1,199	722,035
June	429,289	79,502	20,590	165,807	8,320	75,856	192	112,073	17	5,770	5,007	2,654	905,077
July	459,586	90,486	22,370	167,517	8,153	81,779	179	103,586	16	5,794	4,794	2,597	946,857
August	470,445	87,358	22,471	176,038	8,147	82,347	178	104,665	16	5,644	4,507	1,551	963,367
September	358,697	75,302	20,044	169,106	8,147	74,464	196	102,059	17	5,612	4,010	858	818,512
October	300,079	61,196	15,630	148,015	8,172	69,381	171	96,855	16	5,614	3,473	665	709,267
November	392,900	61,835	21,188	127,259	8,135	71,348	102	92,915	17	5,743	3,289	388	785,119
December	471,672	65,239	26,087	135,464	8,128	97,256	159	88,807	16	5,670	3,156	199	901,853
Total	4,871,368	847,463	257,480	1,773,425	98,432	927,952	1,685	1,176,100	197	68,465	47,425	11,490	10,081,482
Percent	48.320%	8.406%	2.554%	17.591%	0.976%	9.205%	0.017%	11.666%	0.002%	0.679%	0.470%	0.114%	100.000%

STAFF RATE DESIGN AND CLASS COST-OF-SERVICE REPORT

Class Cost-of-Service and Rate Design Overview

A Class Cost of Service (CCOS) study is a detailed analysis where the costs incurred to provide utility service to a particular jurisdiction (e.g., Missouri retail) are assigned to customers, or customer classes, based on the manner in which the costs are incurred. An electric utility's power system is designed, constructed, and operated in order to meet the ongoing energy and load requirements of vast numbers of diverse customers. How and when customers utilize energy has a great bearing on the fixed and variable costs of service. Customer classes are groups of customers with similar electrical service characteristics. For proper cost assignment, the composite load of the system must be differentiated by the various customer classes in order to determine the proportional responsibilities of each customer class. In other words, the customers' load contributions to the total demand are a major cost driver. Staff's CCOS study generally follows the procedures described in Chapter 2 of the NARUC Manual. Staff produces an embedded cost study using historical information developed from data collected over the test year updated through the true-up date set in the case.

Definitions and Fundamental Concepts of Electric CCOS and Rate Design

Cost-of-Service: All the costs that a utility prudently incurs to provide utility service to all of its customers in a particular jurisdiction.

Cost-of-Service Study: A study of total company costs, adjusted in accordance with regulatory principles (annualizations and normalizations), allocated to the relevant jurisdiction, and then compared to the revenues the utility is generating from its retail rates, off-system sales and other sources. The results of a cost-of-service study are typically presented in terms of the additional revenue required for the utility to recover its cost-of-service or the amount of revenue over what is required for the utility to recover its cost-of-service.

Class Cost-of-Service (CCOS) Study: A Class Cost-of-Service study is where a utility's revenue requirement is allocated among the various rate classes of that utility. It is a quantitative analysis of the costs the utility incurs to serve each of its various customer classes. When Staff performs a CCOS study it performs each of the following steps: a) categorize or functionalize costs based upon the specific role the cost plays in the operations of the utility's integrated electrical system; b) classify costs by whether they are demand-related, energy-related, or customer-related; and c) allocate the functionalized/classified costs to the utility's customer classes. The sum of all the costs allocated to a customer class is the cost to serve[1] that class.

Relationship between Cost-of-Service and Class Cost-of-Service: The sum of all *class* cost-of-service in a jurisdiction is the cost-of-service of that jurisdiction. The purpose of a Cost-of-Service study is to determine what portion of a utility's costs are attributable to a particular jurisdiction. The purpose of a Class-Cost-of-Service study is to allocate the cost-of-service study costs to the customer classes in that jurisdiction.

Cost allocation: A procedure by which costs incurred to serve multiple customers or customer classes are apportioned among those customers or classes of customers.

Cost Functionalization: The grouping of rate base and expense accounts according to the specific function they play in the operations of an integrated electrical system. The most aggregated functional categories are production, transmission, distribution and

[1] The cost to serve a particular class is sometimes referred to as the cost-of-service for that class.

customer-related costs, but numerous sub-categories within each functional category are commonly used.

Customer Class: A group of customers with similar characteristics (such as usage patterns, conditions of service, usage levels, etc.) that are identified for the purpose of setting rates for electric service.[2]

Rate Design: (1) A process used to determine the rates for an electric utility once cost-of-service and CCOS is known; (2) Characteristics such as rate structure, rate values, and availability that define a rate schedule and provide the instructions necessary to calculate a customer's electric bill. Rates are designed to collect revenue to recover the cost to serve the class.

Rate Design Study: While a CCOS study focuses on customer class revenue responsibility, a rate design study focuses on how service is priced and billed to the individual customers within each class and to sending appropriate price signals to customers. The rate design process attempts to recover costs in each time period (such as summer/winter seasonal pricing, or peak/off-peak time-of-day pricing) from each rate component for each customer in a way that best approximates the cost of providing service and send appropriate price signals, e.g., costs are higher in the summer so rates are higher in the summer..

Rate Schedule: One or more tariff sheets that describe the availability requirements, prices, and terms applicable to a particular type of retail electric service. A customer class used in a class cost-of-service study may consist of one or more rate schedules.

[2] A customer class used in a class cost-of-service study may consist of one or more rate schedules.

Rate Structure: Rate structure is the composition of the various charges for the utility's products. These charges include

1) customer charge: a fixed dollar amount per month irrespective of the amount of usage;
2) usage (energy) charges: a price per unit charged on the total units of the usage during the month; and
3) peak (demand) usage charge: a price per unit charge on the maximum units of the product taken over a short period of time (for electricity, usually 15 minutes or 30 minutes), which may or may not have occurred within the particular billing month.

More elaborate variations such as seasonal differentials (different charges for different seasons of the year), time-of-day differentials (different charges for different times during the day), declining block rates (lowest per-unit charges for higher usage), hours-use rates (rates which decline as the customer's hours of use – the ratio of monthly usage to maximum hourly usage – increases) are also possible. Different variations are used to send price signals to the customer.

Rate Values (Rates): The per-unit prices the utility charges for each element of its rate structure. Rate values are expressed as dollars per unit of demand (kilowatt), cents per unit of energy (kWh), etc.

Tariff: A document filed by a regulated entity with either a federal or state commission. It describes both the rate values (prices) the regulated entity will charge to provide service to its customers as well as the terms and conditions under which those rate values are applicable.

<u>Class Cost-of-Service Overview on Functionalization, Classification and Allocation</u>

The cost allocation process consists of three major parts: functionalization, classification and allocation.

1. Functionalization

The first step of a CCOS study is functionalization. Functionalization of costs involves categorizing plant investment and operation cost accounts by the type of function with which an account is associated. A utility's equipment investment and operations can be organized along the lines of the function (purpose) that each piece of equipment or task provides in delivering electricity to customers. The result of functionalization is the assignment of plant investment and expenses to the principal utility functions, which include:

1. Production
2. Transmission
3. Distribution
4. Customer Accounts
5. Customer Assistance
6. Customer Sales

Attachment 1 is a diagram of a typical vertically integrated electrical system, and illustrates the concept of functionalization. Electric power is produced at the generation station, transmitted some distance through high voltage lines, stepped down to secondary voltage and distributed to secondary voltage customers. Other customers (high voltage and primary voltage) are served from various points along the system.

In practice, each major Federal Energy Regulatory Commission (FERC) account is assigned to the functional area that causes the cost. This assignment process is called functionalization. Some costs cannot be directly attributed to a single functional area, and are shared between functions -- these costs are refunctionalized to more than one functional area, with the distribution of costs between functions based upon some relating factor.[3] As an example, it is reasonable to assume that social security taxes are directly related to payroll costs so that these taxes can be assigned to functions in the same manner as payroll costs. In

[3] The costs in the FERC account are distributed based on a relationship of the distributed cost to a function rather than all the costs in that account being associated to a particular function.

this case, the ratio of labor costs assigned to the various functional categories becomes the factor for distributing social security taxes between functional groups.

Yet other costs can be clearly attributed to providing service to a particular class of customers, and these costs can be directly assigned to that customer class. Special studies are undertaken by the utility to determine the assignment of costs to customer classes. An example of a direct assignment is the assignment of the cost of transmission equipment used only by a large customer on a particular rate schedule to the rate class associated with that rate schedule.

Functionalized costs are then subdivided into measurable, cost-defining service components. Measurable means that data is available to appropriately divide costs between service components. Cost-defining means that a cost-causing relationship exists between the service component and the cost to be allocated. Functionalized costs are often divided into customer-related costs and demand-related costs. In addition, some functionalized costs can be classified on the basis of the voltage level at which the customer receives electric service.

2. Classification

The second step of a CCOS study is to separate the functionalized costs into classifications based on the components of utility service being provided. Classification is a means to divide the functionalized, cost-defining components into a: 1) customer component, 2) demand component, 3) and an energy component for rate design considerations. The January 1992 edition of the NARUC Manual references customer-related, demand-related, and energy-related cost components for all distribution plant and operating expense accounts, other than for substations and street lighting.

Customer-related costs are the costs to connect the customer to the electrical system and to maintain that connection. Examples of such costs include meter reading expense, billing expense, postage expense, customer accounting expense, customer service expense, and various distribution costs (plant, reserve, and operating and maintenance expenses). The customer components of the distribution system are those costs necessary to make service available to a customer.

Demand-related costs are rate base investment and related operating and maintenance expenses associated with the facilities necessary to supply a customer's service requirements during periods of maximum, or peak, levels of power consumption each month. The major portion of demand-related costs consists of generation and transmission plant and the non-customer-related portion of distribution plant. Demand-related costs are based on the maximum rate of use (maximum demand) of electricity by the customer. In addition, some demand-related investment and costs can be classified on the basis of voltage level at which the customer receives electric service.

Energy-related costs are those costs related directly to the customer's consumption of electrical energy (kilowatt-hours) and consist primarily of fuel, fuel handling, a portion of production plant maintenance expenses and the energy portion of net interchange power costs.

The purpose of classification is to make the third step, allocation, more accurate. For example, assume a special study shows that overhead lines for distribution can be classified into a demand component directly related to a customer's maximum rate of energy usage, and a customer component that is directly related to the fact that a customer exists and requires service. The demand-related portion of overhead distribution line costs can be allocated on the basis of customer maximum demands and the customer-related portion can be allocated on the basis of the number of customers in each class. Typically, the information allowing classification is obtained through special studies of the distribution system. These studies often include statistical analysis of equipment and labor costs, and line losses.

3. Allocation

The third step of performing a CCOS study is called allocation. After the costs have been functionalized and classified, the next step in a CCOS study is to allocate costs to the customer classes. This process involves applying the allocation factors developed for each class to each component of rate base investment and each of the elements of expense specified in the jurisdictional cost of service study. The allocation factors or allocators determine the results of this process. The aggregation of such cost allocations indicates the total annual revenue requirement associated with serving a particular customer class. Allocation factors are chosen that will reasonably distribute a portion of the functionalized costs to each customer class on the basis of cost causation. Allocation factors are typically ratios that represent the fraction of total units (e.g., total number of customers; total annual energy consumption) that are attributable to a certain customer class. These ratios are then used to calculate the fraction of various cost categories for which a class is responsible.

Calculation of Class Net Income and Rate of Return

The operating revenues of each customer class minus its total operating expenses determined through the functionalization, classification and allocation process provide the resulting net income to the utility of each class. The net operating income divided by the allocated rate base of each class will indicate the percentage rate of return being earned by the utility from a particular customer class.

Generation Allocation Methods Listed in NARUC Manual

Utilities design and build generation facilities to meet the energy and demand requirements of their customers on a collective basis. It is impossible to determine which customer classes are being served by which facilities. As such, generation facilities are joint costs used by all customers and allocated to customer classes. Utilities experience periods of high demand during certain times of the year and during various hours of the day (summer hours). All customer classes do not contribute in equal proportions to the varying demands placed on the utility system. Utilities design their mix of generation facilities to minimize the total costs of energy and capacity, while making certain that there is enough available capacity to meet demands for every hour of the year. For example, base load nuclear and coal units require high capital expenditures resulting in large investments per kW, whereas smaller units like gas and oil require less investment per kW but higher variable production costs. It is most cost-effective to build base load units to meet the continuous load of the year and depend on small units to meet the few peak hours of the year. Therefore, production costs vary each hour of the year.

Different parties use different methodologies to allocate generation related plant and expenses. For example, the National Association of Regulatory Commissioners (NARUC) outlined thirteen (13) generation allocation methods in its 1992 Electric Utility Cost Allocation Manual (Manual). The thirteen generation allocation methods are:

1. Single Coincident Peak Method (1-CP)
2. Summer and Winter Peak Method (S/W)
3. Twelve Monthly Coincident Peak (12CP)
4. Multiple Coincident Peak Method
5. All Peak Hours Approach
6. Average and Excess Method (A&E)
7. Equivalent Peaker Methods (EP)
8. Base and Peak Method (B&P)

9. Peak and Average Demand (P&A)
10. Production Stacking Methods
11. Base-Intermediate-Peak (BIP)
12. Loss of Load Probability (LOLP)
13. Probability of Dispatch Method (POD)

A brief description of some of the cost methodologies used most often along with the assumptions and implications are as follows:

Single Coincident Peak Method (1-CP) – The NARUC Manual describes the objective of the 1-CP is to allocate production plant costs to customer classes according to the load of the customer classes at the time of the utility's highest measured one-hour demand in the test year, the class coincident peak load. The calculation translates class load at the time of the system peak into a percentage of the company's total system peak, and applies that percentage to the company's production-demand revenue requirements. The basic premise of the 1-CP method is that an electric utility must have enough capacity available to meet its customers' peak coincident demand. Strengths of this methodology are that the concepts are easy to understand and the data to conduct the CCOS are relatively simple and easy to obtain. The weaknesses are that the sole criteria is based on load during a single hour of the year; the results of the 1-CP method can be unstable from year to year, i.e., if peak occurs on a weekend or holiday, the class contributions to the peak load will be significantly different if the peak occurred during a weekday. Also, when using this methodology there can be free ride allocation. In this context, free ridership is when service rendered completely off-peak is not assigned any responsibility for capacity costs. An example of the free ride allocation may occur for street lighting. Street lights are not on during the day and would be allocated no capacity costs at all if the peak occurred during daylight hours.

The system peak typically occurs on days with extreme weather. Therefore this allocation methodology will allocate more costs to weather sensitive classes and less costs to non-weather sensitive classes than other methodologies.

Summer and Winter Coincident Peak (S/W Peak) – The NARUC Manual describes the objective of S/W Peak method is to reflect the effect of two distinct seasonal peaks on customer cost assignment. This approach may be used if the summer and winter peaks are close in value. The S/W Peak method was developed because some utilities annual peak load occurs in the summer for certain years and in the winter during other years. This method has essentially the same strengths and weaknesses as the 1-CP method except that two hours are used to define the class allocations for generating facilities.

Twelve Monthly Coincident Peak (12-CP) - The NARUC Manual describes this method as an allocator based on the class contribution to the 12 monthly maximum system peaks. This method is usually used when the monthly peaks lie within a narrow range for all twelve months. Most electric utilities have distinct seasonal load patterns such as high peaks in the summer months and lower peaks during the winter, spring and autumn months. However, depending on types of heating options available, winter months may be equal or exceed summer month peaks. This method may be appropriate for some electric utilities where the winter heating season is within a narrow band with the summer cooling season.

The 12-CP method assigns class responsibilities based on their respective contributions throughout the year more closely matching the fact that utilities use all of their resources during the highest peaks, and only use their most efficient plants during lower peak periods than the 1-CP and S/W Peak methods. Weaknesses of this method are that the utility must accurately track load data for all twelve months and customer classes who have major off-peak usage may not receive its fair share of generation facilities. A strength of this method is that a utility can allocate its proportion of cost using twelve months of data information and this method takes into account some class diversity in allocations. The percent allocated to weather sensitive classes is not as great as with the 1-CP and S/W Peak methods.

<u>Average and Excess Method (A&E)</u> – The NARUC Manual describes the A&E method as a method that allocates production plant costs to rate classes using factors that combine the classes' average demands and non-coincident peak (NCP) demands. All production plant costs are usually classified as demand related. The A&E method consists of two parts. The first component of each class's allocation factor is its proportion of the class' total average demand (based on energy consumption) times the system load factor. The second component of each class's allocation factor is called the "excess" demand factor. This component is multiplied by the remaining proportion of production plant (1 minus system load factor). The first and second components (Average and Excess components) are then added to obtain the total allocator. A weakness of this method is that the allocation favors high load factor customers, e.g., classes with industrial customers, and disfavors customer classes with lower load factor customers, e.g., residential and small commercial classes, because the "excess" portion of the allocator uses non-coincidental peak information. Some of the non-coincidental peaks for classes may not occur in peaking seasons. Strengths are that no class of customers will receive a free-ride under this method, e.g., street lighting, and recognition is given to average consumption as well as to additional costs imposed by certain classes for not maintaining a perfectly constant load.

<u>Equivalent Peaker (EP)</u> – The NARUC Manual describes EP as a method based on generation expansion planning practices, which consider peak demand loads and energy loads separately in determining the need for additional generating capacity and the most cost-effective type of capacity to be added. The EP method often relies on planning information in order to classify individual generating units as energy or demand-related and considers the need for a mix of base load, intermediate load, and peaking load generation resources. The EP method has some appeal because base load units that operate with high capacity factors are allocated largely on the basis of energy consumption with costs shared by all classes based on their usage, while peaking units that are seldom used are allocated based on peak demands to those classes contributing to the system peak load. With the EP method, only the combustion turbines and the combustion turbines equivalent capacity cost portion of all other units are treated as demand related. The remainder of the total plant investment is thus treated as energy related. A strength of the EP method is that base load units that operate with high capacity factors are allocated largely on the basis of energy consumption with costs shared by all classes based on their usage, while peaking units used sparingly and only called upon

during peak periods are allocated based on peak demands to those classes contributing to the system peak load. One weakness of this method is that it requires a significant amount of data.

Peak and Average (P&A) – The NARUC Manual describes the impetus for this method as some regulatory commissions recognizing that energy loads are an important determinant of production plant costs, requiring the incorporation of judgmentally-established energy weightings into cost studies. The allocator is effectively the average of adding together each class's contribution to the system peak demand and its average demand. This methodology premise is that a utility's actual generation facilities are placed into service to meet peak load and to serve customers demands throughout the entire year. This method assigns capacity cost partially on the basis of contributions to peak load and partially on the basis of consumption throughout the year or peak period. Strengths of this methodology are an attempt to recognize the capacity/energy allocation in the assignment of fixed capacity costs and that data requirements are minimal. Weaknesses are that the capacity/energy allocation method may have the perception that double-counting occurs in the capacity/energy allocation.

Base-Intermediate-Peak (BIP) – The NARUC Manual describes the BIP method as a time-differentiated method that assigns production plant costs to three rating periods: (1) peak hours, (2) secondary peak (intermediate hours), and (3) base loading hours. The BIP method is based on the concept that specific utility system generation resources can be assigned in the cost of service analysis as serving different components of load (base, intermediate, and peak). The BIP method is an accepted allocation method that attempts to recognize the capacity/energy trade-off that exists within a utility's generation asset portfolio. A utility's base load units tend to operate during all periods of the year (less outages or maintenance) to satisfy energy requirements in the most efficient manner possible during minimum periods. Because base load units operate regardless of peak requirements, they are appropriately classified as energy related. Intermediate plants serve a dual purpose in that they are partially energy-related and partially-demand related. Peaking plants operate with high variable cost and are only utilized to help meet peak period demands. As such, peaker generating facilities plants are classified as peak demand-related. The BIP method considers the differences in the capacity/energy trade off that exist across a company's generation mix. Strengths of the BIP method are that there are three different components being allocated to the various rate classes. There is a base component (based on energy), an intermediate component based on demands less base portion, and a peaking component based on demands less the base and intermediate components already allocated to the classes. The BIP method is one of several methods that allow for a complete recognition of the dual nature of generating resources and provides a structured and precise way to model the costs and develop appropriate class allocators for production plant. Another strength is that each generating unit may be classified as a base, intermediate, or peak generating facility based on fuel costs, heat rates, and operating hours in its classification or the method may allocate investment in production plant and facilities as a whole and does not require an analysis of individual generating units. An additional strength is it eliminates free ridership by customer classes with a substantial off-peak usage. A general weakness is that the BIP method may not be appropriate for utilities that purchase the majority of their energy needs or for utilities with an inefficient mix of generating resources.

Time of Use (TOU) – A production allocation method that assigns production costs to each hour of the year that the specific production occurs. The TOU method apportions production plant accounts for both demand and energy characteristics as each much satisfy both periods of normal use throughout the year and intermittent peak use. The TOU is used for analyzing cost of service by time periods. This method requires analyzing an actual or estimated hourly load curve for the utility and identifying the generating units that would normally be used to serve each hourly load. Previous Staff employee Mike Proctor refined this process with the Commission adopting the TOU methodology in previous cases in Case No. EO-78-161, Case No. EO-85-17, and Case No. ER-85-60. Strengths of the method is that all 8,760 hours are analyzed and assigned to rate groups. Also, each class of customers is assigned their share of costs for the entire test year period. Weaknesses are that a lot of data is needed to analyze and the data needs to be weather normalized for each hour. The Commission rejected this method in a previous case noting that the TOU is unreliable because it considers every hour in the year to be a demand peak.

FAC Tariff Sheet Comparison

	Ameren Mo	GMO	Empire
Accumulation period definition	The historical calendar months during which fuel and purchased power costs, including transportation, net of OSSR for all kWh of energy supplied to Missouri retail customers are determined	None	The six calendar months during which the actual costs subject to this rider will be accumulated for purposes of determining the CAF
Proposal	The four 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 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)	
Recovery Period definition	The billing months as set forth in the above table during which the difference between the Actual Net Fuel Costs during an Accumulation Period and NBFC are applied to and recovered through retail customer billings on a per kWh basis, as adjusted for service voltage level.	the billing months during which the Cost Adjustment Factor (CAF) for each of the respective accumulation periods are applied to retail customer billings on a per kilowatt-hour (kWh) basis	The billing months during which CAF is applied to retail customer billings on a per kilowatt-hour (kWh) basis
Proposal	The billing months during which FAR is applied to retail customer usage on a per kilowatt-hour (kWh) basis adjusted for service voltage		
Filing date	By set date	By set date	set date
Proposal	60 days prior to the first billing cycle read date for the first billing month in the recovery period	By set date	By set date
Adjustment Amount ($) name	Third Subtotal	Fuel Adjustment Clause (FAC), Fuel and Purchased Power Adjustment, FPA, FAC Costs, FAC	FAC, Fuel Adjustment Clause

FAC Tariff Sheet Comparison

	Ameren Mo	GMO	Empire
Proposal	Fuel and Purchase Power Adjustment (FPA)		
$/kWh charge before voltage adj	FPA rate, FPA_c rate, FPA_c	Cost Adjustment Factor (CAF) CAF, Current annual CAF Annual CAF, Forth Interim Total	Cost Adjustment Factor (CAF) and CAF
Proposal	Fuel Adjustment Rate (FAR)		
$/kWh charge for recovery period for that just ended	$FPA_{(RP)}$	Current period CAF Single Accumulation Period CAF	Cost Adjustment Factor (CAF) and CAF
Proposal	FAR_{RP}	FAR_{RP}	FAR
$/kWh charge for prior period	$FPA_{(RP-1)}$ and $FPA_{(RP-2)}$	Previous period CAF Single Accumulation Period CAF	N/A
Proposal	FAR_{RP-1}	FAR_{RP-1}	N/A
Adjustment for losses	Voltage level adjustment factors	Expanded for losses Expansion factors, XF XF_{Sec} and XF_{Pri}	Expansion factors
Proposal	Voltage Adjustment Factors (VAF), VAF_{SEC}, VAF_{PRI}, and VAF_{TRAN}		
Voltage adjusted $/kWh charge	FPA rate, FPAc (with voltage level adjustment)	Annual CAF, FPA CAF	
Proposal	FAR_{SEC}, FAR_{PRI}, and FAR_{TRAN}		

FAC Tariff Sheet Comparison

	Ameren Mo	GMO	Empire
Base definition	net output calculation in the fuel run used in part to determine Net Base Fuel Costs, as included in the Company's retail rates	Base energy costs are costs as defined in the description of TEC (Total Energy Cost).	are calculated using the costs included in the revenue requirement upon which Empire's general rates are set for fuel including the costs associated with the Company's fuel hedging program; purchased power energy charges, including applicable transmission fees; Southwest Power Pool variable costs, Air Quality Control consumables, such as anhydrous ammonia, limestone, and powder activated carbon, and emission allowance costs, but not purchased power demand costs as off-set by off-system sales revenue, any emission allowances revenues and renewable energy credit revenues in the accumulation period. Base energy cost per kWh: cost per kWh at the generator , established in the most recent base rate case
Proposal	Base energy costs are ordered by the Commission in the last rate case consistent with the costs and revenues included in the calculation of the FPA		
Base acronym $	Net Base Fuel Costs (factor NBFC), NBFC and First Subtotal	B and Base energy cost	B and Base Energy Cost
Proposal	Net Base Energy Costs (B)		

FAC Tariff Sheet Comparison

	Ameren Mo	GMO	Empire
Base energy $/kWh name	NBFC rate, Net Base Fuel Costs and NBFC	Applicable Base Energy Cost, base energy cost	Base energy cost per kWh
Proposal	Base Factor (BF)		
Name of filing to change rate	Fuel and Purchased Power Adjustment (FPA) filing, FPA filing	None	Cost Adjustment Factor (CAF) filing
Proposal	Fuel Adjustment Rate filing		
Fuel Costs	Included in CF	FC	F
Proposal	Set out separately as FC		
Cost of Purchased Power	CPP	PP	P
Proposal	PP		
Off-System Sales Revenues	OSSR	OSSR	O
Proposal	OSSR		
Interest calculation	Monthly based on the weighted average interest rate paid on the Company's short-term debt	As applied to deferred electric energy costs: at a rate equal to the weighted average interest paid on short-term debt No explanation for true-up interest calculation	The Company's short-term interest rate
Proposal	Monthly based on the weighted average interest rate paid on the Company's short-term debt.		Monthly based on the interest rate paid on the Company's short-term debt.
Under/over recovery amount	R – includes interest	C – includes accumulated interest	C - doesn't mention interest
Proposal	T. Interest would be in a separate term (I)		
Accumulation Period kWh	S_{AP}	NSI and total system kWh, net system input	NSI kWh and NSI
Proposal	S_{AP}		
Recovery Period kWh	S_{RP}	RNSI	S

FAC Tariff Sheet Comparison

	Ameren Mo	GMO	Empire
Proposal	S_{RP}		
True-up filing timing	In conjunction with an adjustment to its FAC	At the end of each recovery period	Upon completion of each recovery period
Proposal	In conjunction with an adjustment to its Fuel Adjustment Rate (FAR)		
Actual Energy Cost name	CF also called Actual Net Fuel Costs	TEC – consists of FC, EC, PP, TC and OSSR	None
Proposal	Actual Net Energy Costs (ANEC)		
Emissions Cost	Included in CF	EC – net emissions costs	E – Actual total system net emission allowance cost and revenue
Proposal	Explicit in equation as "E"		
Transmission costs	Not mentioned	TC – for off-system sales	Included in description of base energy cost, not mentioned elsewhere
Proposal	Include in purchase power costs. Explicitly mention in tariff as portion of purchased power costs		
Jurisdictional factor acronym	N/A	J and Energy retail ratio	J and Missouri Energy Ratio
Proposal	N/A	Missouri Retail Energy Ratio (J)	
Prudence disallowances included in under/ over recovery	Modifications as a result of prudence reviews	Modifications due to prudence reviews	This factor will reflect any modifications due to prudence reviews
Proposal	Modifications as ordered by the Commission as a result of prudence reviews		
Other changes allowed in under/over recovery	Other disallowances and reconciliations		
Proposal	Other disallowances and reconciliations as ordered by Commission, if any		
Interest included in under/over recovery	Yes	Yes	No
Proposal	Should be included in tariff language		
REC revenues included	No	No	Yes – factor R

FAC Tariff Sheet Comparison

	Ameren Mo	GMO	Empire
Proposal	If included in FAC designate as REC		
Prudence amount return	Shall be returned to customers with interest at a rate equal to the weighted average interest rate paid on the Company's short-term debt.	Adjustments, if any, necessary by Commission order pursuant to any prudence review shall also be placed in the FAC for collection unless a separate refund is ordered by the Commission	In C ➔ This factor will reflect any modifications made due to prudence reviews
Proposal	Adjustments by Commission order pursuant to any prudence review shall also be placed in the FPA for collection unless a separate refund is ordered by the Commission		
Prudence amount designation	None	None	None
Proposal	P		
Emission type allowed	SO_2 and NO_x emissions allowances	Costs in Acct 509 or any other Acct FERC may designate for emission expenses in the future	Emission allowance costs in Acct 509 and 254.103
Proposal	Type of emission allowance (e.g., SO_2, NO_x) as ordered by Commission with appropriate FERC account		

FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
RIDER FAC
For service on and after XX-XX-XXXX.

The two six-month accumulation periods, the two six-month recovery periods and filing dates are set forth in the following table:

Accumulation Periods	Filing Dates	Recovery Periods
September - February	By April 1	June - November
March - August	By October 1	December – May

The Company will make a Fuel Adjustment Rate ("FAR") filing by each Filing Date. The new FAR rates for which a filing is made will be applicable starting with the recovery period that begins following the Filing Date. All FAR filings shall be accompanied by detailed workpapers supporting the filing in an electronic format with all formulas intact.

DEFINITIONS

ACCUMULATION PERIOD:
The six calendar months during which the actual costs and revenues subject to this rider will be accumulated for the purpose of determining the FAR.

RECOVERY PERIOD:
The billing months during which a FAR is applied to retail customer usage on a per kilowatt-hour (kWh) basis.

BASE ENERGY COSTS AND REVENUES:
Base energy costs are ordered by the Commission in the last rate case consistent with the costs and revenues included in the calculation of the Fuel and Purchase Power Adjustment ("FPA").

BASE FACTOR ("BF"):
The base factor is the base energy cost divided by net generation kWh determined by the Commission in the last general rate case. BF = $0.03223 per kWh for each accumulation period.

FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
RIDER FAC
For service on and after XX-XX-XXXX.

APPLICATION
FUEL & PURCHASE POWER ADJUSTMENT

$$FPA = \{[(FC + PP + E + TC - OSSR - REC - B) * J] * 0.85\} + T + I + P$$

Where:

FC = Fuel Costs Incurred to Support Sales:

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

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

PP = Purchased Power costs:

The following costs or revenues reflected in FERC Account Number 555: purchased power costs, purchased power demand costs associated with purchased power contracts with a duration of one year or less, settlements, insurance recoveries, and subrogation recoveries for purchased power expenses, virtual energy charges, generating unit price adjustments, load/export charges, energy position charges, ancillary services including penalty and distribution charges, hedging costs, broker commissions, fees, and margins, SPP EIS market charges, and SPP Integrated Market charges (see note A. below)

E = Net Emission Costs:

The following costs and revenues reflected in FERC Account Numbers 509, 411.8 and 411.9 (or any other account FERC may designate for emissions expenses in the future): emission allowance costs offset by revenues from the sale of emission allowances including any associated hedging costs, broker commissions, fees, commodity based services, and margins.

TC = Transmission Costs:

The following costs reflected in FERC Account Number 565 (excluding Base Plan Funding costs): transmission costs that are necessary to receive purchased power to serve native load and transmission costs that are necessary to make off-system sales.

OSSR = Revenue from Off-System Sales:

A. The following revenues or costs reflected in FERC Account Number 447: all revenues from off-system sales but excluding revenues from full and partial requirements sales to Missouri municipalities that are associated with Empire, hedging costs, SPP EIS market charges, and SPP Integrated Market revenues (see note A. below)

REC = Renewable energy credit revenue:

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

Hedging Costs = Hedging costs are defined as realized losses and costs (including broker commission fees and margins) minus realized gains associated with mitigating volatility in the Company's cost of fuel, fuel additives, fuel transportation, emission allowances, transmission and purchased power costs, including but not limited to, the Company's use of derivatives whether over-the counter or exchange traded including, without limitation, futures or forward contracts, puts, calls, caps, floors, collars, and swaps.

Note A. In anticipation of the implementation of the SPP Integrated Market, the Company and the Missouri Public Service Commission Staff (Staff) will meet quarterly to discuss and review the charge types proposed by SPP and the new market. The Company will provide a listing of charge types and definitions to discuss. Staff and other interested intervenors will provide feedback relating to those costs included in the Fuel Adjustment Clause. Documentation of the quarterly meetings will be filed with the most closely following monthly Section 5 report to be filed with the Commission.

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

B = Net base energy cost is calculated as follows:

$B = (S_{AP} * \$0.03223)$

S_{AP} = Actual net system input at the generation level for the accumulation period.

$$J = \frac{\text{Missouri retail kWh sales}}{\text{Total system kWh sales}}$$

Where Total system kWh sales includes sales to Missouri municipalities that are associated with Empire and excludes off-system sales.

T = True-up of over/under recovery of FAC balance from prior recovery period as included in the deferred energy cost balancing account. Adjustments by Commission order pursuant to any prudence review shall also be placed in the FPA for collection unless a separate refund is ordered by the Commission.

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

P = Prudence disallowance amount, if any, as defined below.

FUEL ADJUSTMENT RATE

The FAR is the result of dividing the FPA by estimated recovery period S_{RP} kWh, rounded to the nearest $0.00000. The FAR shall be adjusted to reflect the differences in line losses that occur at primary and above voltage and secondary voltage by multiplying the average cost at the generator by 1.0502 and 1.0686, respectively. Any FAR authorized by the Commission shall be billed based upon customers' energy usage on and after the authorized effective date of the FAR. The formula for the FPA is displayed below.

$$FAR = \frac{FPA}{S_{RP}}$$

Where:

S_{RP} = Forecasted Missouri NSI kWh for the recovery period.

$$= \text{Forecasted total system NSI} * \frac{\text{Forecasted Missouri retail kWh sales}}{\text{Forecasted total system kWh sales}}$$

Where Forecasted total system NSI kWh sales includes sales to Missouri municipalities that are associated with Empire and excludes off-system sales.

FUEL & PURCHASE POWER ADJUSTMENTRIDER FAC
For service on and after XX-XX-XXXX.

PRUDENCE REVIEW

Prudence reviews of the costs subject to this 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 shall be returned to customers. Adjustments by Commission order, if any, pursuant to any prudence review shall be included in the FAR calculation in P above unless a separate refund is ordered by the Commission. Interest on the prudence adjustment will be included in I above.

TRUE-UP OF FPA

In conjunction with an adjustment to its FAR, the Company will make a true-up filing with an adjustment to its FAC on the first Filing Date that occurs after completion of each recovery period. The true-up adjustment shall be the difference between the revenues billed and the revenues authorized for collection during the true-up recovery period, i.e. the true-up adjustment. Any true-up adjustments or refunds shall be reflected in item T above and shall include interest calculated as provided for in item I above.

FUEL & PURCHASE POWER ADJUSTMENT
RIDER FAC
For service on and after XX-XX-XXXX.

Accumulation Period Ending:			Month, Day, Year
1	Total Energy Cost(TEC) = (FC+PP+E+TC-OSSR-REC)		
2	Net Base Energy Cost (B)	-	
	2.1 Base Factor (BF)		
	2.2 Accumulation Period NSI (S_{AP})		
3	(TEC-B)		
4	Missouri Energy Ratio (J)	*	%
5	(TEC-B)*J		
6	Fuel Cost Recovery	*	%
7	(TEC-B)*J * 0.85		
8	True-Up Amount (T)	+	
9	Prudence Adjustment Amount (P)	+	
10	Interest (I)	+	
11	Fuel and Purchased Power Adjustment (FPA)	=	
12	Forecasted Missouri NSI (S_{RP})	÷	
13	Current Period Fuel Adjustment Rate (FAR) to be applied to bills Beginning XX-XX-XXXX	=	
14	Current Period FAR_{Prim} = FAR x VAF_{Prim}		
15	Prior Period FAR_{Prim}	+	
16	Current Annual FAR_{Prim}		
17	Current Period FAR_{Sec} = FAR x VAF_{Sec}		
18	Prior Period FAR_{Sec}	+	
19	Current Annual FAR_{Sec}		
	VAF_{Prim} = X.XXXX		
	VAF_{Sec} = X.XXXX		

Primary Voltage Adjustment Factor (VAF_{PRIM}) = 1.0502
Secondary Voltage Adjustment Factor (VAF_{SEC})= 1.0686

FUEL & PURCHASE POWER ADJUSTMENT
RIDER FAC
For service on and after XX-XX-XXXX.

THE EMPIRE DISTRICT ELECTRIC COMPANY

P.S.C. Mo. No. 5 Sec. 4 1st Revised Sheet No. 17h

Canceling P.S.C. Mo. No. 5 Sec. 4 Original Sheet No. 17h

For ALL TERRITORY

FUEL & PURCHASE POWER ADJUSTMENT- CLAUSE
~~FUEL ADJUSTMENT CLAUSE~~
~~SCHEDULE~~RIDER FAC
For service on and after XX-XX-XXXX.

The two six-month accumulation periods, the two six-month recovery periods and filing dates ~~will be as follows~~are set forth -in the following table:

Accumulation Periods	**Filing Dates**	**Recovery Periods**
September - February	By April 1	June - November
March - August	By October 1	December -– May

	~~ACCUMULATION PERIOD~~	~~RECOVERY PERIOD~~	~~ACCUMULATION PERIOD~~	~~RECOVERY PERIOD~~
	~~SEPTEMBER~~	~~JUNE~~	~~MARCH~~	~~DECEMBER~~
	~~OCTOBER~~	~~JULY~~	~~APRIL~~	~~JANUARY~~
	~~NOVEMBER~~	~~AUGUST~~	~~MAY~~	~~FEBRUARY~~
	~~DECEMBER~~	~~SEPTEMBER~~	~~JUNE~~	~~MARCH~~
	~~JANUARY~~	~~OCTOBER~~	~~JULY~~	~~APRIL~~
	~~FEBRUARY~~	~~NOVEMBER~~	~~AUGUST~~	~~MAY~~
~~Filing date:~~		~~April 1st~~		~~October 1st~~

The Company will make a ~~Cost Adjustment Factor~~Fuel Adjustment Rate ("~~CAF~~FAR") filing by each Filing Date. The new ~~CAF~~FAR rates for which a~~the~~ filing is made will be applicable starting with the recovery period that begins following the Filing Date. All ~~CAF~~FAR filings shall be accompanied by detailed workpapers supporting the filing in an electronic format with all formulas intact.

DEFINITIONS

ACCUMULATION PERIOD:
The six calendar months during which the actual costs and revenues subject to this rider will be accumulated for the purpose~~s~~ of determining the ~~CAF~~FAR.

RECOVERY PERIOD:
The billing months during which a ~~CAF~~ FAR is applied to retail customer ~~billings~~ usage on a per kilowatt-hour (kWh) basis.

BASE ENERGY COSTS AND REVENUES:
Base energy costs are ordered by the Commission in the last rate case consistent with the costs and revenues included in the calculation of the Fuel and Purchase Power Adjustment ("FPA"). ~~Base Energy Cost in this FAC are calculated using the costs included in the revenue requirement upon which Empire's general rates are set for fuel including the costs associated with the Company's fuel~~

DATE OF ISSUE July 6, 2012 DATE EFFECTIVE August 5, 2012
ISSUED BY Kelly S. Walters, Vice President, Joplin, MO

FUEL & PURCHASE POWER ADJUSTMENT- CLAUSE

~~FUEL ADJUSTMENT CLAUSE~~

~~SCHEDULE~~RIDER FAC

For service on and after XX-XX-XXXX.

~~hedging program; purchased power energy charges, including applicable transmission fees; Southwest Power Pool variable costs, Air Quality Control System consumables, such as anhydrous ammonia, limestone, and powder activated carbon, and emission allowance costs, but not purchased power demand costs as off-set by off-system sales revenue, any emission allowance revenues, and renewable energy credit revenues in the accumulation period.~~

BASE FACTOR ("BF") ~~ENERGY COST PER kWh~~:

~~Base energy cost per kWh at the generator, established in the most recent base rate case.~~ The base ~~energy~~ factor ~~cost per kWh~~ is the base energy cost divided by net generation kWh determined by the Commission in the last general rate case. BF = $0.0~~2837~~3223 per kWh for each accumulation period.

FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
~~FUEL ADJUSTMENT CLAUSE~~
~~SCHEDULE~~ RIDER F~~P~~PAC~~AC~~
For service on and after XX-XX-XXXX.

APPLICATION

FUEL & PURCHASE POWER ADJUSTMENT~~FUEL ADJUSTMENT CLAUSE~~

~~The average price per kWh of electricity generated or purchased will be adjusted subject to application of the FAC, and approved by the Public Service Commission. The price will reflect 95 percent of the accumulation period costs either above or below base costs specified below for:~~

~~Fuel and AQCS consumables consumed in Company electric generating plants;~~

~~Purchased energy (excluding demand);~~

~~Off-system sales revenue;~~

~~Emission allowance costs and revenues; and~~

~~Renewable energy credit revenues.~~

~~It will also include:~~

~~An adjustment for the prior recovery period's over/under recovery of FAC Costs;~~

~~Interest at a rate equal to the Company's short-term interest rate will be applied to the average monthly deferred electric energy costs and will be accumulated during the accumulation period. Deferred electric energy cost shall be determined monthly. The monthly deferred amount may be negative or positive during the accumulation period.~~

~~The formula and components are displayed below.~~

FPAA~~C~~ = {[(FC + PP + E + TC– OSSR - REC - B) * J] * 0.~~9~~85} + ~~C~~T + I + P

Where:

FC = Fuel Costs Incurred to Support Sales:

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

The following costs reflected in FERC Account Number 547: natural gas generation costs related to commodity, oil, transportation, storage, fuel losses, hedging costs for natural gas, oil, and natural gas used to cross-hedge purchased power, fuel additives, and settlement proceeds, insurance recoveries, subrogation recoveries for increased fuel expenses, broker commissions and fees. ~~Actual total cost of fuel - FERC Accounts 501 & 547 (excluding fixed pipeline reservation charges and fixed pipeline storage charges), and AQCS consumables – FERC Account 506.2.~~

PP = Purchased Power costs:
~~Actual total system cost of purchased energy - FERC Account 555 (excluding purchase power demand charges).~~
The following costs or revenues reflected in FERC Account Number 555: purchased power costs, purchased power demand costs associated with purchased power contracts with a duration of one year or less, settlements, insurance recoveries, and subrogation recoveries for purchased power expenses, virtual energy charges, generating unit price adjustments, load/export charges, energy position charges, ancillary services including penalty and distribution charges, hedging costs, broker commissions, fees, and margins, SPP EIS market charges, and SPP Integrated Market charges (see note A. below)

E = Net Emission Costs ~~Actual total system net emission allowance cost and revenues - FERC Accounts 509 & 254.103~~:

The following costs and revenues reflected in FERC Account Numbers 509, 411.8 and 411.9 (or any other account FERC may designate for emissions expenses in the future): emission allowance costs offset by revenues from the sale of emission allowances including any associated hedging costs, broker commissions, fees, commodity based services, and margins.

TC = Transmission Costs:

The following costs reflected in FERC Account Number 565 (excluding Base Plan Funding costs): transmission costs that are necessary to receive purchased power to serve native load and transmission costs that are necessary to make off-system sales.

OSSR = Revenue from Off-System Sales:

~~Actual total system o~~Off-system sales revenue.~~A. The following revenues or costs reflected in FERC Account Number 447: all revenues from off-system sales but excluding revenues from full and partial requirements sales to Missouri municipalities that are associated with Empire~~GMO~~, hedging costs, SPP EIS market charges, and SPP Integrated Market revenues (see note A. below)

REC = Renewable energy credit revenue~~s.~~:

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

Hedging Costs = Hedging costs are defined as realized losses and costs (including broker commission fees and margins) minus realized gains associated with mitigating volatility in the Company's cost of fuel, fuel additives, fuel transportation, emission allowances, transmission and purchased power costs, including but not limited to, the Company's use of derivatives whether over-the counter or exchange traded including, without limitation, futures or forward contracts, puts, calls, caps, floors, collars, and swaps.

Note A. In anticipation of the implementation of the SPP Integrated Market, the Company and the Missouri Public Service Commission Staff (Staff) will meet quarterly to discuss and review the charge types proposed by SPP and the new market. The Company will provide a listing of charge types and definitions to discuss. Staff and other interested intervenors will provide feedback relating to those costs included in the Fuel Adjustment Clause. Documentation of the quarterly meetings will be filed with the most closely following monthly Section 5 report to be filed with the Commission.

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

THE EMPIRE DISTRICT ELECTRIC COMPANY

P.S.C. Mo. No.	5	Sec.	4	1st	Revised Sheet No.	17i
Canceling P.S.C. Mo. No.	5	Sec.	4		Original Sheet No.	17i

For ALL TERRITORY

FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
~~FUEL ADJUSTMENT CLAUSE~~
~~SCHEDULE~~ RIDER FPAC~~AC~~
For service on and after XX-XX-XXXX.

B = Net ~~B~~base energy cost is ~~-~~calculated as follows:

~~1. For each accumulation period~~ B = (~~NSI kWh~~S_{AP} * $0.03223~~2837~~)

S_{AP}~~NSI~~ = Actual net system input at the generation level for the accumulation period.

DATE OF ISSUE July 6, 2012 DATE EFFECTIVE August 5, 2012
ISSUED BY Kelly S. Walters, Vice President, Joplin, MO

Schedule MJB-3-6

FUEL & PURCHASE POWER ADJUSTMENT~~FUEL ADJUSTMENT CLAUSE~~
~~SCHEDULE~~RIDER F~~P~~AC~~AC~~
For service on and after XX-XX-XXXX.

~~R = Renewable energy credit revenues.~~

J = ~~Missouri energy ratio calculated as follows:~~

~~Missouri energy ratio =~~Missouri retail kWh sales / Total system kWh sales

Where Total system kWh sales includes sales to Missouri municipalities that are associated with Empire and excludes off-system sales.

T~~C~~ = True-up of over/under recovery of FAC balance from prior recovery period as included in the deferred energy cost balancing account. ~~This factor will reflect any modifications made due to prudence reviews.~~ Adjustments by Commission order pursuant to any prudence review shall also be placed in the FPA for collection unless a separate refund is ordered by the Commission.

I = Interest applicable to (i) the difference between Total energy cost (FC + PP + E + TC – OSSR – REC) and Net base energy cost (“B”) multiplied by the Missouri energy ratio (“J”) for all kWh of energy supplied during an AP until those costs have been recovered; (ii) refunds due to prudence reviews (“P”), if any; and (iii) all under- or over-recovery balances created through operation of this FAC, as determined in the true-up filings (“T”) provided for herein. Interest shall be calculated monthly at a rate equal to the weighted average interest paid on the Company’s short-term debt, applied to the month-end balance of items (i) through (iii) in the preceding sentence.~~Interest.~~

P ~~+~~= Prudence disallowance amount, if any, as defined below.

~~COST~~ FUEL ADJUSTMENT ~~FACTOR~~RATE

The FAR~~CAF~~ is the result of dividing the ~~FAC~~ FPA by estimated recovery period ~~Missouri net system input (NSI)~~S_{ARP} kWh, rounded to the nearest \$0.00000. The ~~CAF~~ FAR shall be adjusted to reflect the differences in line losses that occur at primary and above voltage and secondary voltage by multiplying the average cost at the generator by 1.0502 and 1.0686, respectively. Any ~~CAF~~ FAR authorized by the Commission shall be billed based upon customers’ energy usage on and after the authorized effective date of the ~~CAF~~FAR. The formula for the FPA is ~~and components are~~ displayed below.

$$\cancel{CAF}\ FAR = \frac{FPA\cancel{AC}}{S_{RP}}$$

Where:

FUEL & PURCHASE POWER ADJUSTMENT~~FUEL ADJUSTMENT CLAUSE~~
~~SCHEDULE~~RIDER F~~P~~PAC~~AC~~
For service on and after XX-XX-XXXX.

S_{RP} = Forecasted Missouri NSI kWh for the recovery period. ~~Missouri NSI kWh is calculated as:~~

~~Missouri NSI~~ = Forecasted total system NSI * Forecasted Missouri retail kWh sales / Forecasted total system kWh sales

Where Forecasted ~~t~~Total ~~s~~System NSI kWh ~~s~~Sales includes sales to Missouri municipalities that are associated with Empire and excludes off-system sales.

PRUDENCE REVIEW

Prudence reviews of the costs subject to this 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 shall be returned to customers. Adjustments by Commission order, if any, pursuant to any prudence review shall be included in the FAR calculation in P above unless a separate refund is ordered by the Commission. Interest on the prudence adjustment will be included in I above.

~~There shall be a periodic review of fuel and energy costs subject to the FAC and a comparison of the FAC revenue collected. Prudence reviews shall occur no less frequently than at eighteen (18) month intervals.~~

TRUE-UP OF FPAA~~C~~

~~After completion of each recovery period~~In conjunction with an adjustment to its FAR, the Company will make a true-up filing ~~in conjunction~~ with an adjustment to its FAC on the first Filing Date that occurs after completion of each recovery period. The true-up adjustment shall be the difference between the revenues billed and the revenues authorized for collection during the true-up recovery period ~~in the recovery period to the costs authorized for collection in the recovery period~~, i.e. the true-up adjustment. Any true-up adjustments or refunds shall be reflected in item ~~C~~ T above and shall include interest calculated as provided for in item I above.

THE EMPIRE DISTRICT ELECTRIC COMPANY

P.S.C. Mo. No. 5 Sec. 4 3rd Revised Sheet No. 17k

Canceling P.S.C. Mo. No. 5 Sec. 4 2nd Revised Sheet No. 17k

For ALL TERRITORY

FUEL & PURCHASE POWER ADJUSTMENT~~FUEL ADJUSTMENT CLAUSE~~
~~SCHEDULE~~RIDER FAC~~ACPA~~
For service on and after XX-XX-XXXX.

Accumulation Period Ending:			Month, Day, Year
1	~~Actual Net Energy Cost (ANEC)~~Total Energy Cost(TEC) = (FC+PP+E+TC--OSSR-REC)		
2	Net Base Energy Cost (B)	-	
	2.1 Base Factor (BF)		
	2.2 Accumulation Period NSI (S_{AP})		
3	(~~AN~~TEC-B)		
4	~~Jurisdictional Factor~~Missouri Energy Ratio (J)	*	%
5	(~~AN~~TEC-B)*J		
6	~~Customer Responsibility~~Fuel Cost Recovery	*	%
7	~~__% *(~~(~~AN~~TEC-B)*J~~)~~ * 0.85		
8	True-Up Amount (T)	±	
9	Prudence Adjustment Amount (P)	±	
10	Interest (I)	±	
11	Fuel and Purchased Power Adjustment (FPA)	=	
12	Forecasted Missouri NSI (S_{RP})	÷	
13	Current Period Fuel Adjustment Rate (FAR) to be applied to bills Beginning XX-XX-XXXX	=	
14	Current Period FAR_{Prim} = FAR x VAF_{Prim}		
15	Prior Period FAR_{Prim}	+	
16	Current Annual FAR_{Prim}		
17	Current Period FAR_{Sec} = FAR x VAF_{Sec}		
18	Prior Period FAR_{Sec}	+	
19	Current Annual FAR_{Sec}		
	VAF_{Prim} = ~~1.0502~~X.XXXX		
	VAF_{Sec} = ~~1.0686~~X.XXXX		

~~ACCUMULATION PERIOD ENDING, (XX-XX-XXXX)~~

~~1. Total energy cost (F + P + E – O - R) $XXXXXXXX~~

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FUEL & PURCHASE POWER ADJUSTMENT~~FUEL ADJUSTMENT CLAUSE~~
~~SCHEDULE~~RIDER FAC~~ACPA~~
For service on and after XX-XX-XXXX.

~~2. Base energy cost (B) $XXXXXXXX~~

~~3. Missouri energy ratio (J) XXXXX~~

~~4. Fuel cost recovery [(F + P + E – O - R) – B] * J * 0.95 $XXXXXXX~~

~~5. Adj for over/under recovery for the recovery period ending XX-XX-XXXX (C) $XXXXXX~~

~~Interest (I) $XXXXX~~

~~6. Prudence Disallowance Amount (P) $XXXXX~~

~~7. Fuel Adjustment Clause (FAC) $XXXXXXX~~

~~8. Forecasted Missouri NSI for the recovery period (S) XXXXXXXXXX~~

~~9. Cost Adjustment Factor (CAF) to be applied to bills beginning XX-XX-XXXX $XXXXXX / kWh~~

~~10. CAF - Primary and above (Line 9 x Primary Expansion Factor) $XXXXXX / kWh~~

~~11. CAF - Secondary (Line 9 x Secondary Expansion Factor) $XXXXXX / kWh~~

Primary ~~Expansion Factor~~Voltage Adjustment Factor (VAF_{PRIM}) = 1.0502
Secondary ~~Expansion~~ Voltage Adjustment Factor (VAF_{SEC})= 1.0686

Empire District Electric
ER-2012-0345
DR# 163

Acct	Description
	FUEL
501011	Conv & Seminar-Fuel
501042	Fuel - Coal
501045	Fuel - Oil
501048	Fuel - Petroleum Coke
501054	Fuel - Natural Gas
501183	Sales Of Ash
501211	Ineffect (Gain)Loss Deri Steam
501212	Effective (Gn)Lss Deriv Steam
501214	Rlzd Deriv (Gn)Ls Strg/P&L-Stm
501215	MO/KS Derv Unrecov Fu Ex-Steam
501216	NonFAS133Deriv(Gain)/LossSteam
501300	Fuel - Tires
501400	Ops Labor-Fuel Handling
501401	Ops Mtls-Fuel Handling
501601	Fuel Administration - Asbury
501604	Fuel Administration - Riverton
501605	Fuel Administration Plum Point
501607	Fuel Adm E Trader Commission
501608	Fuel Adm E Trader Option Prem
547205	Natural Gas SLCC Tolling
547206	Nat Gas-Tollng SLCC Ineffectiv
547207	Nat Gas-Tolling SLCC Effective
547208	Comb Turb Fuel Sales - Nat Gas
547210	Combust Turb Fuel Natural Gas
547211	Ineffect (Gain)Loss Deriv Gas
547212	Effective (Gain)Loss Deriv Gas
547213	Fuel - No 2 Oil Fuel
547214	Rlzd Deriv (Gn)Ls Strg/Park&Ln
547300	MO/KS Deriv Unrecov Fuel Exp
547301	NonFAS133 Deriv (Gain)/Loss
547603	Fuel Adm Riverton Gas
547605	Fuel Adm State Line
547606	Fuel Adm Energy Center
547607	Fuel Adm E Traders Commission
547608	Fuel Adm E Traders Option Prem
	AQCS
506201	Limestone Expense
506202	Ammonia Expense
506203	Powdered Activated Carbon
506204	Lime Expense
	Purchase Power
555430	Direct Purchases
555431	Purchase Power Tolling Fees
555432	Energy Imbalance
555436	Purchased Power Exchanged Spa
555437	Interrupt Svc Compensation
	Emissions
509052	Emission Allowance Exp

Empire District Electric
ER-2012-0345
DR# 163

Acct	Description
254103	Gain-Disposition of Emis Allow
	REVENUE
447610	Energy Imbalance - Arkansas
447620	Energy Imbalance - Kansas
447630	Energy Imbalance - Missouri
447640	Energy Imbalance - Oklahoma
447113	Gen Ark Off-Sys Sale-Resale
447124	Gen Ks Off-System Sale-Resale
447430	Aec - Off-Sys-Missouri
447133	Gen Mo Off-Sys Sale-Resale
447540	Oklahoma G R D A Off-System
447143	Gen Ok Off-Sys Sales-Resale
565419	Off Sys Sales Trans Costs
	Renewable Energy Credit
556415	REC Fees & Commissions
456071	Misc Elec Rev-Green Credits-AR
456072	Misc Elec Rev-Green Credits-KS
456073	Misc Elec Rev-Green Credits-MO
456074	Misc Elec Rev-Green Credits-OK

Detailed Description

Cost associated with education seminars for fuel personal
Cost of coal burned
Cost of oil burned
Cost of pet coke burned
Cost of natural gas burned
Sale of coal ash
FAS 133 Ineffective derivative gain/loss
FAS133 Effective derivative gain/loss
Derivative gain/loss distributed to park and loan gas
Unrecoverable portion of unrealized mtm gain/loss
Derivative gain/loss
Cost of tires burned
Fuel handling labor costs
Fuel handling material costs
Administration cost for Asbury associated with fuel
Administration cost for Riverton associated with fuel
Administration cost for Plum Point associated with fuel
Broker commission expense
Option premium cost
Gas burn cost for tolling
FAS133 Ineffectiveness derivative gain/loss
FAS133 derivative gain/loss
Sale of excess natural gas
Gas burn cost
FAS133 Ineffectiveness derivative gain/loss
FAS133 derivative gain/loss
Cost of No 2 fuel oil burned
Derivative gain/loss distributed to park and loan gas
Unrecoverable portion of unrealized mtm gain/loss
Derivative gain/loss
Administration costs associated with Riverton gas consumption
Administration costs associated with State Line gas consumption
Administration costs associated with Energy Center gas consumption
Broker commission expense
Option premium cost

Air quality consumables used

Direct Purchases
Purchase Power Tolling Fees
Energy Imbalance
Purchased Power Exchanged
Compensation for Interruption of service per contracts

Emission Allowance Expense

Detailed Description
Gain-Disposition of Emission Allowance
Revenue allocated to Arkansas for Energy Imbalance
Revenue allocated to Kansas for Energy Imbalance
Revenue allocated to Missouri for Energy Imbalance
Revenue allocated to Oklahoma for Energy Imbalance
Revenue allocated to Arkansas for Off Systems Sales
Revenue allocated to Kansas for Off Systems Sales
Revenue allocated to Associated Electric for their portion of Off Systems Sales
Revenue allocated to Missouri for Off Systems Sales
Revenue allocated to Grand River Dam for their portion of Off Systems Sales
Revenue allocated to Oklahoma for Off Systems
Transmission costs associated with Off System Sales
Commissions and fees associated with Renewable Energy Credits
Revenue associated with Renewable Energy Credits for Arkansas
Revenue associated with Renewable Energy Credits for Kansas
Revenue associated with Renewable Energy Credits for Missouri
Revenue associated with Renewable Energy Credits for Oklahoma