MISSOURI PUBLIC SERVICE COMMISSION

RATE DESIGN
AND
CLASS COST-OF-SERVICE
REPORT

KCP&L GREATER MISSOURI OPERATIONS COMPANY
FILE NO. ER-2010-0356

Jefferson City, Missouri
December 1, 2010

Denotes Highly Confidential Information

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Table of Contents

STAFF'S

CLASS COST-OF-SERVICE

AND

RATE DESIGN REPORT

I. Executive Summary

Staff's Class Cost-of-Service (CCOS) and Rate Design objectives in this case are:

1. To present an overview of Staff's CCOS study results for MPS—that part of KCP&L Greater Missouri Operations Company's (GMO) service area in and about Kansas City and for L&P—that part of GMO's service area in and about St. Joseph. The CCOS study is based upon the test year of January 1, 2009 through December 31, 2009, updated through June 30, 2010, and trued-up through December 31, 2010.
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 in rates any Commission-ordered overall changes in customer revenue responsibility.
4. Retain, to the extent practical, 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.
5. Provide the Commission with a recommendation for a high efficiency street and area lighting tariff provision.
6. Modify the fuel adjustment clause (FAC) tariff sheets to be consistent with Staff recommendations in the Staff's Revenue Requirement Cost-of-Service Report (COS Report) filing made on November 17, 2010 and to simplify and clarify current FAC language.

Staff's CCOS Report is organized into the following main sections. They are:

- Executive Summary
- Class Cost-of-Service and Rate Design Overview
- Staff Class Cost-of-Service Study - MPS and L&P
- Rate Design – MPS and L&P
- Miscellaneous Tariff Issues
- High Efficiency Street and Area Lighting
- Fuel adjustment clause – MPS and L&P

The results of Staff's CCOS study for GMO are summarized in Table 1 below. Table 1 shows the rate revenue shifts necessary for the current rate revenues from each customer class to exactly match with Staff's determination of GMO's cost of serving that class. Staff developed its analysis of the cost of serving each class using inputs taken from the Staff's COS Report and the Staff Accounting Schedules. Staff's customer classes correspond to GMO's current rate schedules, except that MPS primary[1] and secondary general service customers were combined into one class, L&P Limited Demand, Short Term, and separate meter general service customers were combined,[2] into one class, all MPS lighting rate schedules were combined into one customer class, and all L&P lighting rate schedules were combined into another class. Staff's customer classes are shown in Table 1 below.

[1] MPS only has three general service customers that are served at primary.
[2] Each billed on service charge and energy charge by season (no demand).

Table 1

Summary Results of Staff's Revenue Neutral CCOS Study – MPS			
Customer Class/Rate Schedule	CCOS % Increase	Less: System Average	Revenue Neutral % Increase
RESIDENTIAL			
Regular	4.80%	-1.02%	3.78%
Space Heating	1.33%	-1.02%	0.31%
Other	-37.30%	-1.02%	-38.31%
SMALL GENERAL SERVICE			
Primary and Secondary	-5.52%	-1.02%	-6.54%
ND (non demand)	-17.29%	-1.02%	-18.31%
Short Term without Demand	-23.47%	-1.02%	-24.49%
LARGE GENERAL SERVICE			
Primary	0.17%	-1.02%	-0.85%
Secondary	-2.63%	-1.02%	-3.65%
LARGE POWER SERVICE			
Primary	3.96%	-1.02%	2.94%
Secondary	-0.56%	-1.02%	-1.57%
LIGHTING	17.13%	-1.02%	16.11%
TOTAL	1.02%	-1.02%	0.00%

Summary Results of Staff's Revenue Neutral CCOS Study - L&P			
Customer Class/Rate Schedule	CCOS % %Increase	Less: System Average	Revenue Neutral % Increase
RESIDENTIAL			
Regular	23.85%	-21.86%	1.99%
Other	44.82%	-21.86%	22.95%
Space Heating	28.51%	-21.86%	6.64%
GENERAL SERVICE			
General Use	-8.27%	-21.86%	-30.13%
Limited Demand, Short Term, Separate Mtr. SH/WH	-16.40%	-21.86%	-38.26%
LARGE GENERAL SERVICE			
Primary, Secondary, and Substation (1 rate schedule)	14.82%	-21.86%	-7.04%
LARGE POWER SERVICE			
TOU - Primary, Secondary, Substation, Transmission (1 rate schedule)	28.77%	-21.86%	6.91%
LIGHTING - All	18.71%	-21.86%	-3.15%
TOTAL	21.86%	-21.86%	0.00%

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 GMO 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 has overpaid. 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 has underpaid.

Staff's recommended customer class revenue adjustments are an attempt to bring each customer class closer to GMO's cost to serve that class while still maintaining rate continuity and stability, revenue stability, and minimize rate shock to any customer class.

Because Staff developed separate revenue requirements for MPS and L&P in its COS Report, Staff has different recommendations for revenue neutral customer class revenue responsibility shifts for MPS and L&P. Based on Staff's CCOS study results, Staff recommends that each MPS customer class with a negative revenue shift percentage (revenue from the class exceeds the cost to serve) over ten percent (-10%) receive no rate increase for any Commission ordered increase for MPS up to and including $5 million; and that each MPS customer class with a positive revenue shift percentage (cost to serve exceeds revenue from the class) over ten percent (+10%) share the first $5 million of any rate increase on an equal percentage basis; and for any increase above $5 million, Staff recommends that the additional amount above $5 million be allocated to all MPS customer classes on an equal percentage basis. The impact of the first $5 million on the affected customer classes would be an increase in their rates of approximately an additional 1%. Based on Staff's CCOS study results, Staff recommends that each L&P customer class with a positive revenue shift percentage (cost to serve exceeds revenue) share the first $3 million of any Commission ordered rate increase for L&P on an equal percentage basis; and, for any increase above $3 million, Staff recommends that the additional amount above $3 million be allocated to all L&P customer classes on an equal percentage basis. The impact of the first $3 million on the affected customer classes would be an increase in their rates of approximately an additional 1%.

Staff's recommended customer class revenue adjustments would bring each customer class closer to GMO's cost to serve that class while still maintaining rate continuity and stability, revenue stability; and minimize rate shock to any customer class.

Staff also recommends the Commission order GMO to complete its evaluation of Light Emitting Diode (LED) Street and Area Lighting (SAL) systems and, no later than twelve (12) months of the effective date of the Commission's Report and Order in this case, file proposed LED lighting tariff sheet(s) to offer a LED SAL demand-side program, unless GMO's analysis shows that a LED SAL demand-side program would not be cost-effective. If a LED SAL demand-side program is not cost-effective, update the Staff as to the finding's rationale and file a proposed tariff sheet(s) that would provide LED SAL services at cost to its customers.

Staff recommends changes to the FAC tariff sheets to implement the changes identified in the Staff's COS Report and update the expansion factors used. Staff also recommends changes to the FAC tariff sheet to simplify and clarify current FAC language

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 jurisdictional cost of providing electric service to all the customer classes in a manner which best reflects cost causation. Since those jurisdictional costs equate to the utility's jurisdictional 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 within a given jurisdiction -- Missouri retail in this case.

Appendix A 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 Staff's 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 studies appear in Table 1 (MPS and L&P) above and are outlined in Schedules MSS-1 and MSS-2. They show the changes to the current rate revenues of each customer class required to exactly match that customer class's rate revenues with GMO'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 GMO's rate of return from each customer class.

Revenue neutral means that the revenue shifts among classes do not change the utility's total system revenues. Staff finds 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 1.02% for MPS and 21.86% for L&P from each MPS or L&P customer class's required percentage increase to rate revenue, respectively, to match the revenues GMO should receive from that class to match GMO's cost to serve that class.

For example, based on Schedule MSS-1, on a revenue neutral basis, the Residential - Regular customer (MPS) class is providing 4.80% fewer revenues to GMO than GMO's cost to serve that class. Also, the Small General Service No Demand customer class (MPS) is providing 17.29% more revenues to GMO than GMO's cost to serve that class. Staff's CCOS study results for all nineteen (19) customer classes it used (eleven for MPS and eight for L&P) are found, separated by MPS and L&P, in Schedule MSS-1 and Schedule MSS-2, respectively.

Because a CCOS study is not precise and the results can vary according to the allocation methodologies chosen, it should be used only as a guide for designing rates. In addition, bill impacts need to be considered. While reducing over collection from customer classes with negative revenue shift percentages (revenues greater than cost to serve) is appealing, the bill impact on the customer classes with positive revenue shift percentages must be considered. Based on its study results and judgment, Staff recommends revenue neutral adjustments to many GMO rate schedules.

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

A. Data Sources

Staff's CCOS studies are a continuation of the Staff's revenue requirements positions for MPS and L&P, as filed on November 17, 2010, through Staff's direct revenue requirement cost of service recommendation for GMO's retail jurisdictional cost of service. This data includes:

- Adjusted jurisdictional investment and cost data by FERC account;
- Annualized, normalized rate revenues;
- Fuel and purchased power costs;
- Other operating and maintenance expenses;
- Depreciation and amortizations;
- Taxes; and
- Off-system sales.

In addition, data was also obtained from GMO witness Paul Normand's Direct Testimony and Workpapers from this case, including:

- Customer demand splits;
- Customer coincidental peaks per rate schedule;
- Customer non-coincidental peaks per rate schedule;
- Customer maximums per rate schedule;
- Annual energy per rate schedule; and
- Certain other allocation factors for specific customer allocations (CUST4, CUST5, CUST6, CUST10, CUST 18, CUST21). These relate to information on services, meters, meter readings, uncollectible accounts, customer premise installations, and customer deposits.

B. Classes and Rate Schedules

GMO currently provides service to its customers in a number of rate classifications 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 demand meters (e.g., no demand or short term service without demand).

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 is allocated by designated base plants, intermediate plants, and peaking plants. The designated plants for each group (base, intermediate, and peak) is allocated to each customer class based on plant investment and costs associated with the 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, a portion of production plant maintenance expenses and the energy portion of net interchange power costs. The charts below show the percentage of total costs associated within each major function for MPS (Table 2) and L&P (Table 3).

Table 2

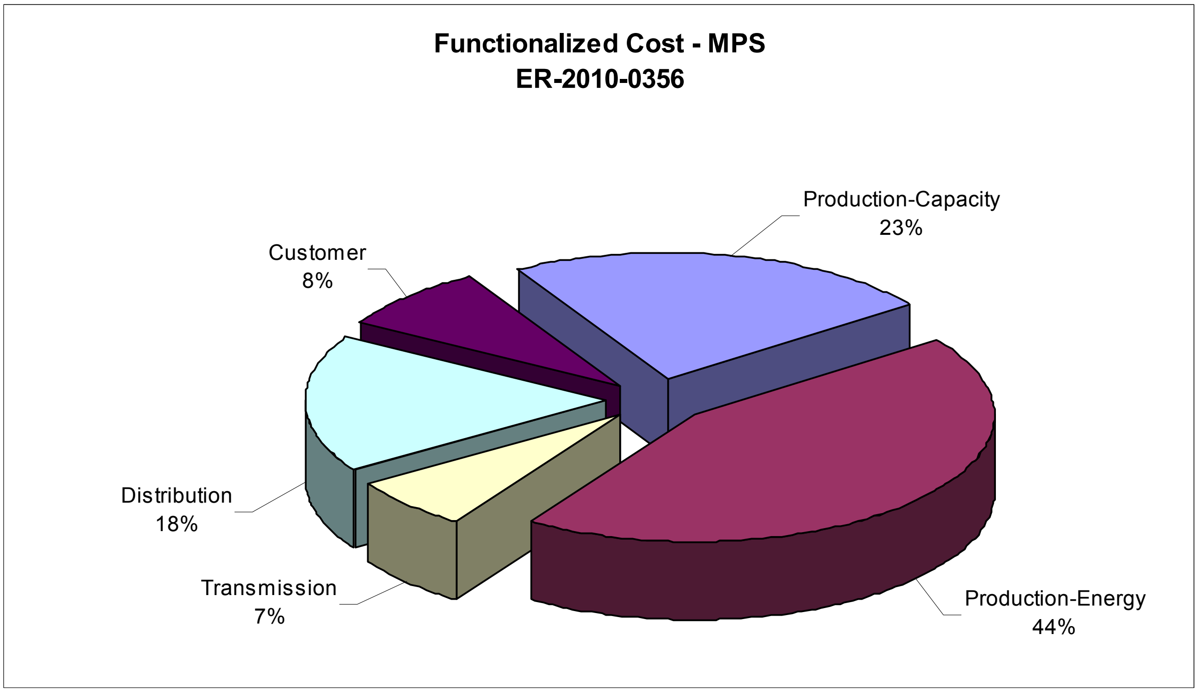
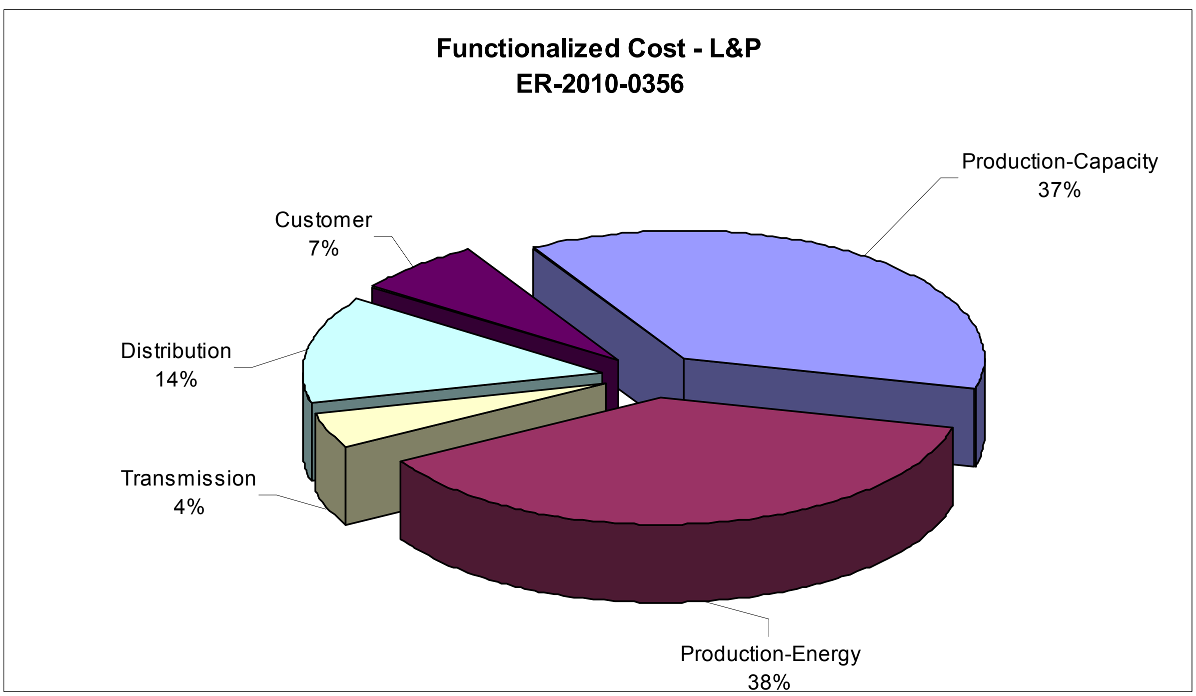


Table 3



The Production Function (combination of Production-Capacity and Production-Energy) is the single largest cost component, and represents 67% of the total cost for MPS and 75% for L&P. The Distribution Function, at 18% for MPS and 14% for L&P of the total cost, is the second largest contributor to total cost, and includes substations, overhead (OH) and underground (UG) lines, and line transformers, as well as the costs to operate and maintain this equipment. Customer Services at 8% for MPS and 7% for L&P, and Transmission at 7% for MPS and 4% for L&P round out the total cost. Schedule MSS-3 provides a detailed description of each external allocation factor Staff used in its CCOS study.

D. Allocation of Production Costs

Allocators are used to distribute the functionalized costs to the customer classes. The Production investment and costs comprise approximately 67% (MPS) and 75% (L&P) of the functionalized investment and cost. Both the demand and energy characteristics of GMO's load are important determinants of production investment and costs, since production must produce output to satisfy periods of normal use and intermittent peak use throughout the year. These functionalized costs are: 1) Production–Capacity, and 2) Production–Energy.

Staff allocated Production–Capacity costs and Production-Energy fuel costs based on a Base-Intermediate-Peak (BIP) method. The BIP method is based on recognition that both capacity and energy requirements are an important determinant of Production–Capacity investment and costs. With the 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;

2. An intermediate component consisting of the average 12 NCP[3] 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[4] 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, January 1992[5] (NARUC Manual). Schedule MSS-4 details the BIP method as described in the NARUC Manual. The BIP method is 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. In the BIP method, generating units are ranked from lowest to highest based on operating costs. The lowest operating cost units are considered base load units. 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 for when they need maintenance. Because base load units operate regardless of peak requirements, they are appropriately classified as energy-related.[6] 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.[7] Older coal units sometimes are in this category. Gas–fired combined cycle units are also generally considered intermediate units. Peaking units have low capital costs, are relatively quick to build—typically twelve to eighteen months—but are costly to run. It is most cost effective to only run these units for the few

[3] 12 NCP is each month's maximum peak demand of each customer class at any time during the months of January through December.
[4] 3 NCP is each month's maximum peak demand of each customer class during June, July, and August
[5] The BIP method is outlined in the NARUC Manual in Part IV C Section 2.
[6] **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, a portion of production plant maintenance expenses and the energy portion of net interchange power costs.
[7] **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 during periods of maximum, or peak, levels of power consumption.

hours of the year when the system load is the highest. Peaking units are used to follow the energy requirements of the system on a real-time basis.

GMO operates and maintains generating units that are required to provide both capacity and energy for its customers throughout the year. Prudency requires that GMO 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 GMO's system, both instantaneously and over time.

In order to recognize the generating units in an equitable manner, for purposes of its CCOS study, Staff reviewed the energy produced at each unit—including anticipated energy output for Iatan 2— based on the normalized and annualized, capacity and energy produced by each generating unit from Staff's fuel model for MPS and L&P. Staff then classified each generating unit as a base, intermediate, or peak load requirement to satisfy periods of normal use and intermittent peak use throughout the year. This review resulted in grouping GMO's generating units into base, intermediate, and peak categories. The category groupings are summarized below and provided in detail in Schedule MSS-5:

- Base generating units – First generating units available to meet GMO's base load requirements. The base generating units consist of the most efficient coal plants and short term purchases to satisfy GMO's requirements.
- Intermediate generating units – Generating plants that would be used to meet additional load requirements after the dispatch of base units. Staff after reviewing Schedule MSS-5, determined that generating units owned by GMO are either used as base or peaking as shown on Schedule MSS-5 based on fuel cost and generating hours.
- Peak generating units – Generating units that would be used to meet peak load requirements to satisfy capacity loads in any hour. The peak generating plants consist of GMO's combustion turbine plants.

The BIP method Staff used to allocate production-capacity costs is based on a recognition that generation is built to meet both peak demands and energy usage. For GMO, the basic components of the 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; and
2. 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 the base portion allocated to it, the base portion allocated to the class is subtracted.

The first step of the BIP method is to evaluate the system monthly loads of the test period. A listing of monthly peak loads, Table 4 below, helps to define the twelve months in terms of a peak season and a non-peak season. For the MPS area GMO is a summer peaking utility (see Table 4) with the system's four highest monthly coincident peaks (CP) occurring in the summer season (June through September).

TABLE 4
Coincident System Peak @ Generation - MPS

Month	kW	% of Annual Peak
Jan-09	1,150,720	75.0%
Feb-09	1,064,295	69.4%
Mar-09	867,100	56.5%
Apr-09	823,026	53.6%
May-09	1,025,829	66.9%
Jun-09	1,380,127	89.9%
Jul-09	1,534,456	100.0%
Aug-09	1,531,583	99.8%
Sep-09	1,180,504	76.9%
Oct-09	817,304	53.3%
Nov-09	968,460	63.1%
Dec-09	1,173,100	76.5%

For the L&P area GMO is a winter and summer peaking utility (see Table 5) with the system's six highest monthly CP peaks occurring in three winter months (December, January, February) and three summer months (June, July, August).

TABLE 5
Coincident System Peak @ Generation - L&P

Month	kW	% of Annual Peak
Jan-09	461,826	100.0%
Feb-09	434,179	94.0%
Mar-09	367,718	79.6%
Apr-09	323,648	70.1%
May-09	293,464	63.5%
Jun-09	412,583	89.3%
Jul-09	431,804	93.5%
Aug-09	444,604	96.3%
Sep-09	376,075	81.4%
Oct-09	300,321	65.0%
Nov-09	348,964	75.6%
Dec-09	425,941	92.2%

In the BIP method, the base allocator (B portion of BIP method) is calculated on each class's annual usage at generation in the test year. This level of demand formed the basis to allocate the capacity requirements to each customer class for production investment and costs. Because the Staff determined that none of the generation units could be classified as intermediate, the final step is to determine the peak portion (P portion of BIP method) for allocation to the various classes. The peak portion is allocated to the various classes based on each class's share of the summer months less the base portion already allocated to the various classes. Staff used the three highest peaks during the test year for calculating the production–capacity cost allocator since the three highest peaks are in excess of the winter load requirements for GMO (MPS and L&P combined).

Schedule MSS-5 is a schedule showing GMO (both MPS and L&P) fuel and purchased power costs. Staff uses a balancing methodology between MPS and L&P to allocate fuel and purchased power costs. Staff developed this methodology in Case No. ER-2009-0090, GMO's most recent past electric rate case. This method fairly distributes fuel expenses and purchased power expenses between MPS and L&P. For further explanation, see Staff Revenue Requirement Cost of Service Report filed on November 17, 2010 (pp. 85 – 86).

E. Allocation of Transmission Costs

The Transmission investment and costs comprise approximately 7% (MPS) and 4% (L&P) of the functionalized investment and costs to the classes. GMO's transmission system consists of highly integrated bulk power supply facilities, high voltage power lines and substations that transport power to other transmission or distribution voltage facilities. Transmission costs are allocated by Staff to customer classes on a 12 coincident peak (12 CP) basis[8]. The 12 CP allocation methodology is used as it includes periods of normal use and intermittent peak use throughout all twelve months of the year.

F. Allocation of Distribution Costs

Voltage level is a factor that Staff considered when allocating distribution costs to classes. A customer's use or non-use of specific utility-owned equipment is directly related to the voltage level requirement of the customer. All residential customers are served at secondary voltage; non-residential customers are served at secondary, primary, substation, or transmission level voltages.

Staff allocated the costs of distribution substations on the basis of each class's annual peak demand measured at substation voltage. Only those customer classes served at

[8] The average of the percent of each class' load at time of system peak for 12 months of January 2009 through December 2009

substation voltage or below (i.e., all substation, primary and secondary customers) were included in the calculation of the allocation factor, so that distribution substation costs were allocated only to those customers that used these facilities. Staff used the annual class peak of customer classes served at substation voltage or below to allocate substation costs because it represents the appropriate level of diversity at the distribution substation.

Staff allocated the costs of distribution primary on the basis of each class's annual peak demand measured at primary voltage. Only those customers served at primary voltage or below (i.e., primary and secondary customers) were included in the calculation of the allocation factor, so that distribution primary costs were allocated only to those customers that used these facilities. Staff used the annual class peak to allocate primary costs because it represents the appropriate level of diversity at the distribution primary voltage.

Load diversity is a condition that exists when the peak demands of customers do not occur at the same time. The spread of individual customer peaks over time reflects the diversity of the class load, and should be used to allocate facilities that are shared by groups of customers. Load diversity is important in allocating demand-related distribution costs because the greater the amount of diversity among customers within a class or among classes, the smaller the total capacity (and total cost) of the equipment required for the utility company to meet its customers' needs. Therefore, when allocating demand-related distribution costs, 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 in the allocation of the demand-related portions of the various distribution function categories.

Table 6 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[9] Conduits/Conductors	Diversified Demand	Low to Moderate
Line Transformers	Diversified Demand	Low to Moderate

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

[9] Overhead (OH)/Underground (UG)

Staff allocated the costs of distribution secondary and line transformers on the basis of diversity factors which include each class's annual peak demand and customer maximum demands. Only secondary customers (i.e., no primary, substation, or transmission voltage 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 used these facilities.

GMO conducted special studies that split the cost of poles, towers, fixtures; and OH and UG distribution lines between the portions that are primary and secondary related.

Meter costs were allocated using GMO's CUST5 allocator. This allocator is based on a GMO 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-related costs are minimum 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 used GMO's allocators CUST6 for allocating meter reading costs, CUST10 for allocating uncollectible accounts, and CUST21 for allocating customer deposits. These three allocators are derived in GMO's studies that directly assign the costs of meter reading, uncollectible accounts, and customer deposits to the classes. The allocators CUST6, CUST10, and CUST21 are the fraction of total costs of meter reading, uncollectible accounts and customer deposits assigned to each class, respectively. Other customer service accounts were allocated on unweighted customer counts or allocated according to GMO's CCOS study.

H. Revenues

Operating revenues consists of two components: the revenue that the Company collects from the sales of electricity to Missouri retail customers (rate revenues); and the revenue the Company receives for providing other services (other revenues). Rate Revenues are also used in developing Staff's rate design proposal and will be used to develop the tariffs required to implement the Commission's ordered revenue requirement and rate design for GMO in this case. GMO's Missouri rate schedules are designated as residential, small general service (MPS only), general service (L&P only), large general service, large power service, and lighting. The residential rate schedules are further distinguished by regular, space heating, and other rate schedules. The general service classifications are distinguished by voltage level, separate space heating, and different demand options. The large power service is distinguished by voltage level (secondary, primary, substation, and transmission). There are also numerous separate Missouri lighting or traffic control signal rate schedules.

Staff Expert: Michael S. Scheperle

IV. Rate Design

Staff's rate design objectives in this case are:

- 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 changes in customer revenue responsibility.
- Retain, to the extent practical, 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. That each MPS customer class with a negative revenue shift percentage (revenue from the class exceeds the cost to serve) over ten percent (-10%) receive no increase for any Commission ordered increase for MPS up to and including $5 million; each MPS customer class with a positive revenue shift percentage (cost to serve exceeds revenue from the class) over ten percent (+10%) share the first $5 million of any rate increase on an equal percentage basis; and for any increase above $5 million, Staff recommends that the additional amount above $5 million be allocated to all MPS customer classes on an equal percentage basis. The impact of the first $5 million on the affected customer classes would be an additional increase of approximately 1%.
2. That each L&P customer class with a positive revenue shift percentage (cost to serve exceeds revenue) share the first $3 million of any Commission ordered rate increase for L&P on an equal percentage basis; and, for any increase above $3 million, Staff recommends that the additional amount above $3 million be allocated to all L&P customer classes on an equal percentage basis. The impact of the first $3 million on the affected customer classes would be an additional increase of approximately 1%.
3. That GMO complete its evaluation of LED SAL systems and, no later than twelve (12) months of the effective date of the Commission's Report and Order in this case, file proposed LED lighting tariff sheet(s) to offer a LED SAL demand-side program in MPS and L&P, or in MPS or L&P, except where GMO's analysis shows that a LED SAL demand-side program would not be cost-effective for MPS or L&P, in which case it shall only be required to offer a LED SAL demand-side program were it is cost-effective, and update Staff as to the finding's rationale where it is not cost effective, and file a proposed tariff sheet(s) that would provide LED SAL services at cost to its customers.
4. That the Base Energy Cost per kWh rates for MPS and for L&P in the FAC tariff sheets be changed to the below rates based upon the following information in Staff's COS Report in this case: 1) Base Energy Cost (fuel and purchased power costs less off-system revenue) for inclusion of Iatan 2 and Staff's adjustments to test

year; 2) updated expansion factors, e. g., loss factors; and 3) normalized net system inputs:

- $0.0251 per kWh for MPS
- $0.0199 per kWh for L&P

Staff's Rate Design General Recommendations

Staff rate design general recommendations are to:

1. Retain all existing rate schedules;
2. Retain all existing rate structures; and
3. Retain the existing rate design of the current rate schedules.

Retain the Current Rate Schedules, Rate Structures, and Rate Design for MPS

The residential rate General Use and Separate Space Heating schedules, rate structures, and rate design consist of the following elements for MPS:

- General Use rate schedule and Separate Space Heating rate schedule
  - Customer Charge — $ per month (12 months)
  - Winter Energy Charge — $ per kWh by kWh rate block (declining block rate structure)
  - Summer Energy Charge — $ per kWh by kWh rate block (inclining block rate structure)
- Residential Other Use rate schedule
  - Customer Charge — $ per month (12 months)
  - Winter Energy Charge — $ per kWh (flat rate)
  - Summer Energy Charge — $ per kWh (flat rate)
- Residential Time of Day rate schedule (no customers)

The non-residential, non-lighting rate schedules consist of the following rate groups, rate schedules, and rate design elements for MPS:

- Small General Service (SGS) rate schedules (secondary, primary-frozen)
  - Customer Charge — $ per month
  - Demand Charge — $ per kW by base and seasonal by season

- Energy Charge — $ per kWh hours of use by base and seasonal by season

- Small General Service (SGS) rate schedules(non-demand, short term without demand)
  - Customer Charge — $ per month
  - Energy Charge — $ per kWh by season (short term without demand)
  - Energy Charge — $ per kWh by base and seasonal by season(non-demand)
- Large General Service (LGS) rate schedules (secondary, primary)
  - Customer Charge — $ per month
  - Demand Charge — $ per kW by base and seasonal by season
  - Energy Charge — $ per kWh hours of use by base and seasonal by season
- Large Power Service (LPS) rate schedules (secondary, primary)
  - Customer Charge — $ per month
  - Demand Charge — $ per kW by base and seasonal by season
  - Energy Charge — $ per kWh hours of use by base and seasonal by season
  - Reactive Charge — $ per kVar (12 months)
- Thermal Energy Storage Pilot Program (frozen) 1 customer
- Real Time Pricing (3 customers)

The customers who belong to the residential class and the lighting class are well defined. The remaining customers generally belong to one of four main rate classes based upon their load and cost characteristics. Staff's intent is to define customer classes that are homogeneous in the statistical sense; namely, the variation in load and cost characteristics among the individuals within the class is smaller than the variation between the classes. The typical customer in each of the main classes can be described as follows:

- Small General Service: very small (under 30 kW – non-demand, short term without demand) (over 30 kW – secondary or primary) commercial or industrial customers with low load factor[10]; almost always served at secondary voltage.

[10] Load factor is the average demand divided by peak demand

- Large General Service: large size (100 kW – 500 kW) commercial or industrial customer with higher load factor; customers must have, or be willing to assume, a 100 kW minimum demand.
- Large Power Service: very large size (500 kW or greater) commercial or industrial customer with very high load factor, customer must have, or be willing to assume, a 500 kW minimum demand.

Within each rate schedule, demand and energy charges should continue to be seasonally differentiated (i.e., summer rates are higher than winter rates). The remaining charges (e.g., customer and reactive) should be constant year-round.

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).

Retain the Current Rate Schedules, Rate Structures, and Rate Design for L&P

The residential rate schedules, rate structures, and rate design consist of the following elements for L&P:

- General Use and Separate Space Heating rate schedules
  - Service Charge $ per month (12 months)
  - Winter Energy Charge $ per kWh by kWh rate block (declining block rate structure)
  - Summer Energy Charge $ per kWh (flat rate)
- Separate Meter – Space Heating/Water heating (frozen) and Residential Other Use
  - Customer Charge $ per month (12 months)
  - Winter Energy Charge $ per kWh (flat rate)
  - Summer Energy Charge $ per kWh (flat rate)
- Residential Time of Day rate schedule

The non-residential, non-lighting rate schedules, rate structures, and rate design consist of the following rate groups and rate elements for L&P:

- General Service (GS) rate schedules (limited demand, separate meter space heating / water heating-frozen, short term)
  - Service Charge — $ for each bill
  - Energy Charge — $ per kWh by season
- General Service (GS) rate schedules (general use)
  - Facilities kW charge — $ per kW
  - Energy Charge — $ per kWh hours use rate by season
- Large General Service (LGS) rate schedules (secondary, primary)
  - Facilities kW charge — $ per kW
  - Demand Charge — $ per kW by season
  - Energy Charge — $ per kWh hours use by season
- Large Power Service (LPS) rate schedules (secondary TOU, primary TOU, substation TOU, Transmission TOU)
  - Facilities Charge — $ per facilities
  - Demand Charge — $ per kW of hours use by season
  - Energy Charge — $ per kWh by "on-peak" "off-peak" by season

The L&P customers who belong to the residential class and the lighting class are well defined. The remaining customers generally belong to one of four main rate classes based upon their load and cost characteristics. Staff's intent is to define customer classes that are homogeneous in the statistical sense; namely, the variation in load and cost characteristics among the individuals within the class is smaller than the variation between the classes. The typical customer in each of the main classes can be described as follows:

- General Service: very small (less than 40 kW – limited demand, short term) (over 40 kW – general use) commercial or industrial customers with low load factor (average demand divided by peak demand); almost always served at secondary voltage.
- Large General Service: large size (40 kW – 500 kW) commercial or industrial customer with higher load factor; customers must have, or be willing to assume, a 40 kW minimum demand.

- Large Power Service: very large size (500 kW or greater) commercial or industrial customer with very high load factor, customer must have, or be willing to assume, a 500 kW minimum demand.

Within each rate schedule, demand and energy charges should continue to be seasonally differentiated (i.e., summer rates are higher than winter rates). The remaining charges (e.g., customer or service charge, facilities) should be constant year-round.

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).

Staff Expert: Michael S. Scheperle

V. Miscellaneous Tariff Issues

GMO made many minor changes to update and correct its tariff sheets. Staff recommends the Commission approve the two proposed definitions of Unauthorized Use and Tampering proposed on new Sheet No. R-5A. GMO's proposed definitions are consistent with KCPL definitions on Sheet No. 1.07A and 1.07, respectfully.

Staff also recommends the Commission approve the deletion of the connection charge of $50 applied outside of normal business hours proposed on Sheet No. R-20, 2.07 B. for the rule and on Sheet No. R-66 for the charge. GMO is the only electric utility that presently has this charge.

Staff recommends the Commission approve changing the partial payment rule on Sheet No. R-34, 6.01 C. as proposed by GMO for billing which includes a previous balance to allow GMO to first credit to previous charges then to previous deposits. This proposal is consistent with KCPL's has this proposed rule change on Sheet No. 1.27, 8.06 Partial Payment.

Staff recommends the Commission approve the addition of a minimum charge of $150 to reconnect a service that had been subject to tampering as proposed on Sheet No. R-66. This is consistent with KCPL's charge. In addition, Staff recommends the following changes to GMO's tariff sheets.

For P.S.C. MO. No. 1 (MPS Rates)
- Sheet No. 92 Private Area Lighting: Add period to "No" (number) to read "No."

P.S.C. MO. No. 1 (Rules and Regulations)
- Sheet No. R-27, 4.02 Protection of Company's Property, Service area part of header: delete the word "all".
- Sheet No. R-34, 6.01 Billing and Reading of Meters, Service area part of header: delete the word "all".

Staff Expert: William (Mack) L. McDuffey

VI. High Efficiency Street and Area Lighting

Staff recommends that the Commission order GMO to complete its evaluation of Light Emitting Diode (LED) Street and Area Lighting (SAL) systems and to file a proposed LED lighting tariff(s) no later than twelve (12) months from a Commission order approving the Company's tariffs filed in compliance with the terms of the Commission's Report and Order in this case or an update to the Commission on when it will file a proposed LED lighting tariff(s).

Current Street Lighting for GMO

Currently, GMO has approximately 36,500 SAL systems for 296 public street and highway lighting customers in its service territory, using a total of about 35,000 MWh annually according to its 2009 Annual Report. The GMO currently approved lighting tariffs consist of 1) Municipal Street Lighting[11], 2) Street Lighting and Traffic Signals[12], and 3)

[11] Tariff Sheet No. 41 and 42 for GMO-L&P and Sheet No. 88, 89 and 90 for GMO-MPS
[12] Tariff Sheet No. 43, 44, 45, and 46 for GMO-L&P

Private Area Lighting[13]. The rates in these schedules include the installation and maintenance costs of the lighting, in addition to the energy costs. All of GMO's SAL systems are owned by GMO and virtually all of the existing installed lighting in its service territory are high pressure sodium (HPS) lamps, which were determined the most efficient available technology for the SAL at the time most of these SALs were installed.

An Alternative to the SAL System: Light Emitting Diode (LED) Lighting

The LED lighting system is the most energy efficient SAL fixtures available today. LED advantages over traditional high-intensity discharge (HID) lamps and HPS lamps include improved efficiency and longer lamp life. Other advantages of LED street lights include:

- Improved night visibility due to higher color rendering, higher color temperature and increased luminance uniformity;
- Reduced maintenance costs;
- No mercury, lead or other known disposable hazards; and
- An opportunity to implement programmable controls (e.g. bi-level lighting).[14]

Studies from Other Utilities and Municipalities

The Pacific Gas and Electric Company (PG&E) offers a LED Street Light Program to non-metered customer-owned street LED lights based on PG&E's LS-2 rate.[15] In PG&E's LED Street Light Program, customers have two types of incentives for replacing traditional (HID and HPS) street lights billed at a fixed LS-2 rate with LED fixtures. First, customers who have installed or replaced existing street light fixtures with LED fixtures are able to switch to a lower billing rate under the LS-2 rate schedule. Second, customers who perform

[13] Tariff Sheet No. 47, 48, and 49 for GMO-L&P and Sheet No. 91, 92 and 93 for GMO-MPS
[14] http://www.pge.com/mybusiness/energysavingsrebates/rebatesincentives/ref/lighting/lightemittingdiodes/streetlightprogram.shtml
[15] See PG&E's LS-2 rate schedule at http://www.pge.com/tariffs/tm2/pdf/ELEC_SCHEDS_LS-2.pdf

such replacements will be eligible for a rebate for every qualified LED fixture purchased and installed.[16]

Southern California Edison (SCE) offers not only a LED street light rate to non-metered customer-owned street lights based on SCE's LS-2 rate[17], but also a 'Midnight' service[18] rate for a programmable lighting system that can turn off or dim at a designated time such as 10 p.m. until 5 a.m., within all of their outdoor lighting tariffs.

The challenge for cities regarding their SAL networks is to increase the quality of lighting service to the community while reducing its operating costs. While citizens consider streetlights a critical safety and public service and complain loudly about lamp failures, they also want city governments to reduce operating budgets. In the last couple of years, hundreds of cities[19] have launched pilot LED SAL programs including some cities in Missouri such as Columbia, Independence, and Springfield.

D. KCPL and GMO's LED SAL Research[20]

KCPL and GMO are collaborating with the Electric Power Research Institute (EPRI) to test and evaluate the potential of currently available LED lighting. The issues that need to be addressed are system compatibility, technology performance, validating industry performance claims and efficacy issues. In particular, assuming the lamps perform reliably, the efficacy of the lamps will determine the total energy savings possible.

EPRI's LED SAL collaboration project involves a test site where HID lighting is being replaced with LED lighting. As a project participant, KCPL and GMO are involved in

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[16] See PG&E's LED Street Light Rebates at http://www.pge.com/mybusiness/energysavingsrebates/rebatesincentives/ref/lighting/lightemittingdiodes/incentives/index.shtml

[17] See SCE's LS-2 rate schedule at http://www.sce.com/NR/sc3/tm2/pdf/ce37-12.pdf

[18] Robert Wagner from the International Dark-Sky Association mentions as 'Voluntary Part-Night Rates' for outdoor lighting in Case No. ER-2010-0355 and Case No. ER-2010-0356.

[19] http://newstreetlights.com/index_files/New_Streetlights_News_100.htm

[20] Based on the Data Request No. 0509 for Case No. ER-2010-0355 and on the Data Request No. 0333 for Case No. ER-2010-0356.

the quarterly project measurement process to take readings of the pre-installation HID lighting and the post-installation LED lighting. In addition to testing the efficacy of the LED lighting, the quarterly observations will provide information about degradation, spectrum shift, and reliability and maintenance issues. A significant part of the operating cost savings from LED lighting comes from the reduced need for maintenance and monitoring. The quarterly monitoring will continue until spring 2012, at which time the project will close and a final report will be produced. This report will address the many concerns surrounding the adoption of LED street lighting.

Through data requests responses from KCPL and GMO, Staff has learned that in addition to the EPRI collaboration, KCPL and GMO are conducting a LED pilot program with five (5) area communities where similar test sites will be evaluated using various lighting manufacturers. KCPL and GMO are also evaluating LED incentives within the tariffs of other utilities and will be using the pilot sites to help determine the potential structure of LED lighting tariffs on their system.

E. Staff Recommendation

Staff recommends that the Commission order GMO to complete its evaluation of LED SAL systems and to file a proposed LED lighting tariff(s) no later than twelve (12) months from a Commission order approving the Company's tariffs filed in compliance with the terms of the Commission's Report and Order in this case or an update to the Commission on when it will file a proposed LED lighting tariff(s). Staff is not recommending that GMO offer a LED SAL demand-side program unless GMO's analysis shows that a LED SAL demand-side program would be cost-effective. However, if a LED SAL demand-side program is not cost-effective, the Staff recommends that GMO update the Staff as to the finding's rationale and file a proposed tariff sheet(s) that would provide LED SAL services at cost to its customers.

Staff Expert: Hojong Kang

VII. Fuel and Purchased Power Adjustment Clause (FAC)

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

- Change the sharing mechanism from 95%/5% to 75%/25% to provide the Company with a more appropriate incentive to keep its fuel and purchased power cost down;
- Include language that the Base Energy Cost in the FAC be set equal to the Base Energy Cost in the test year total revenue requirement in the rate case to assure that the Company neither benefits nor is penalized due to the two Base Energy Costs being different; and
- Delete two FERC accounts now in the definition of Purchased Power Cost, since these FERC accounts are for transmission expenses and, therefore, are not consistent with the definition of fuel and purchased power cost in 4 CSR 240-20.090(1)(B).

Staff recommends the Commission change the Base Energy Cost per kWh rates for MPS and for L&P to the below rates based upon the following information in Staff's COS Report in this case: 1) Base Energy Cost (fuel and purchased power costs less off-system revenue) for inclusion of Iatan 2 and Staff's adjustments to test year; 2) updated expansion factors, e. g., loss factors; and 3) normalized net system inputs:

- $0.0251 per kWh for MPS
- $0.0199 per kWh for L&P

Staff will update these Base Energy Cost per kWh rates as part of the test year true-up in this case.

In its tariff filing that started this case, GMO filed revisions to its tariff sheets *numbered 124 through 127.5* with an effective date of May 4, 2011. By letter dated October

22, 2010 filed on October 22, 2010, GMO extended the effective date to June 4, 2010 as per the Non-Unanimous Stipulation and Agreement/Proposed Procedural Schedule of GMO, Staff, Ag Processing, Inc., Sedalia Industrial Energy Users Association, Dogwood Energy LLC, and Missouri Retailers Association filed on July 29, 2010 and approved by the Commission on August 18, 2010. GMO's FAC includes two 6-month accumulation periods, which end on November 30 and May 31. It is likely that the effective date of FAC tariff sheets approved in this case will not be November 30 or May 31, and, therefore, an accumulation period will be covered in part by the currently effective FAC tariff sheets and in part by the new FAC tariff sheets the Commission approves in this case. Therefore, Staff proposes tariff sheets in the form of the exemplar tariff sheets in Schedule JAR-1 be approved in this case. Schedule JAR-1 specifies that the provisions of the current FAC tariff sheets be applicable for determining the difference between actual fuel and purchased power costs less off-system sales revenue and base energy costs calculated using the Base Energy Cost rates in GMO's FAC tariff sheets for service provided prior to the effective date of the new FAC tariff sheets approved in this case and that the provisions of the new FAC tariff sheets be applicable to service provided on and after the anticipated June 4, 2011 effective date of the new FAC tariff sheets.

Staff also recommends that: 1) the factor J (energy retail ratio) be deleted from the FAC, and 2) factor RNSI (forecasted retail net system input) be redefined in the FAC as RNSI = Forecasted recovery period net system input, at the generator, for the calculation of the CAF (cost adjustment factor). These changes have no impact on the resulting CAFs for the FAC, but do result in a more straightforward calculation of the CAFs.

To prevent confusion, Staff further clarifies in the definition of OSSR that OSSR only excludes sales to Missouri municipalities. Staff proposes that the definition of OSSR be changed to include: "Revenues from Off-system Sales shall exclude long-term full and partial requirements sales to Missouri municipalities that are associated with GMO."

Finally, because fuel costs for the Crossroads generating plant are included in GMO's FAC and to be consistent with Staff's position to not include the capital and running costs of the Crossroads generating plant (Crossroads) in its revenue requirement for MPS in its direct case (see Staff's COS Report, page 92, lines 5 through 19), Staff recommends GMO's FAC for MPS include a new Crossroads generating plant factor. The Crossroads generating plant factor (CGP factor) Staff recommends is in the amount of $740,071 annually, which is the difference between Staff's fuel run results for GMO's test year fuel and purchased power costs less off-system sales revenue with Crossroads and Staff's fuel run results for GMO's test year fuel and purchased power costs less off-system sales revenue without Crossroads. Staff recommends that one-half of the estimated annual increase in fuel and purchased power costs less off-system sales revenue due to Crossroads ($370,035) be applied to each 6-month accumulation period for MPS.

Schedule JAR-1 includes all of the changes to the GMO FAC tariff sheets recommended by Staff and described earlier in this section of the Staff CCOS Report. Schedule JAR-2 is a redline version of Schedule JAR-1 on the current FAC tariff sheets *numbered 124 through 127.5*.

Staff Expert/Witness: John A. Rogers

FAC Expansion Factors

Based on results from the Loss Study R154-09, Staff updated system losses for MPS and L&P. These system losses are the basis for calculating the FAC expansion factors. The expansion factors account for the energy losses incurred in the transmission and distribution of energy from the generator to the customer. They are used in the FAC calculations to convert the cost per kWh, at the system input voltage, to the cost per kWh at the customers' metered voltage. This update includes losses for metered secondary voltage, and metered primary voltage and above. In general, the new expansion factors represent a slight decrease for metered primary voltage and above, and a slight increase for metered secondary voltage, when compared to the expansion factors in the current FAC tariff sheets. Tables 1 and 2 provide Staff's proposed new FAC expansion factors.

Table 1: L&P		
Expansion Factors	Voltage Level	
	Primary	Secondary
Current Tariff	1.0444	1.0700
Proposed	**1.0421**	**1.0701**
Change	-0.0023	0.0001

Table 2: MPS		
Expansion Factors	Voltage Level	
	Primary	Secondary
Current Tariff	1.0444	1.0679
Proposed	**1.0419**	**1.0712**
Change	-0.0025	0.0033

Staff Expert/Witness: David Roos

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of the Application of KCP&L Greater Missouri Operations Company for Approval to Make Certain Changes in its Charges for Electric Service	))))	File No. ER-2010-0356

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 accompanying Staff Report on pages 1 through 27, and the facts therein are true and correct to the best of his knowledge and belief..

Michael S. Scheperle
Michael S. Scheperle

Subscribed and sworn to before me this 1 day of December, 2010.

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 Application of KCP&L Greater Missouri Operations Company for Approval to Make Certain Changes in its Charges for Electric Service	))))	File No. ER-2010-0356

AFFIDAVIT OF WILLIAM L. McDUFFEY

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

William L. McDuffey, 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 accompanying Staff Report on pages 27 through 28, and the facts therein are true and correct to the best of his knowledge and belief..

William L McDuffey
William L. McDuffey

Subscribed and sworn to before me this 1st day of December, 2010.

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 Application of KCP&L Greater Missouri Operations Company for Approval to Make Certain Changes in its Charges for Electric Service	))))	File No. ER-2010-0356

AFFIDAVIT OF HOJONG KANG

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

Hojong Kang, 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 accompanying Status Report on pages 28 through 32, and the facts therein are true and correct to the best of his knowledge and belief.

Hojong Kang

Hojong Kang

Subscribed and sworn to before me this 1st day of December, 2010.

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 Application of KCP&L Greater Missouri Operations Company for Approval to Make Certain Changes in its Charges for Electric Service	))))	File No. ER-2010-0356

AFFIDAVIT OF JOHN A. ROGERS

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

John A. Rogers, 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 accompanying Staff Report on pages 32 through 34, and the facts therein are true and correct to the best of his knowledge and belief..

John A Rogers

John A. Rogers

Subscribed and sworn to before me this 1st day of December, 2010.

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 Application of KCP&L Greater Missouri Operations Company for Approval to Make Certain Changes in its Charges for Electric Service	))))	File No. ER-2010-0356

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 accompanying Staff Report on pages 34 through 35, 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 1st day of December, 2010.

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

STAFF CLASS COST-OF-SERVICE AND RATE DESIGN REPORT

APPENDIX

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 customer-

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

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 describes the availability requirements, prices, and terms applicable to a particular type of retail electric service. A customer class is 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

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

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

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

Appendix A1 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 this case, the ratio of labor costs assigned to the various functional categories becomes the factor for distributing social security taxes between functional groups.

[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.

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

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

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.

<u>Generation Allocation Methods Listed in NARUC Manual</u>

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 experiences 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
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:

<u>Single Coincident Peak Method (1-CP)</u> – 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.

<u>Summer and Winter Coincident Peak (S/W Peak)</u> – 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.

<u>Twelve Monthly Coincident Peak (12-CP)</u> - 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. Weakness 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 a great as with the 1-CP and S/W Peak methods.

Average and Excess Method (A&E) – 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.

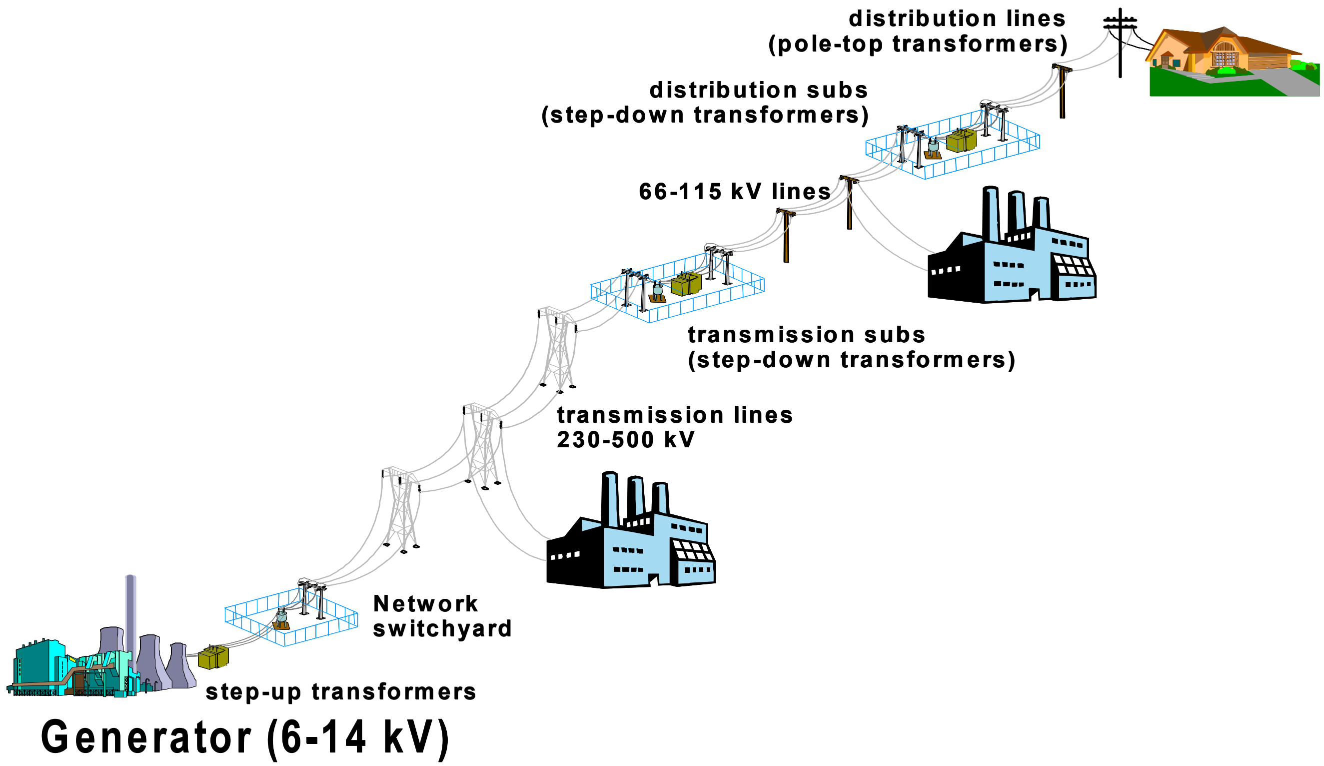
Equivalent Peaker (EP) – The NARUC Manual describes EP as a method based on generation expansion planning practices, which consider peak demand loads and energy loads separately in determining the need for additional generating capacity and the most cost-effective type of capacity to be added. The EP 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. Another strength is that each generating plant is classified as a base, intermediate, or peak generating facility based on fuel costs, heat rates, and operating hours in its classification. 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 in unreliable because it considers every hour in the year to be a demand peak.

Basic Components of Electricity Production and Delivery



Missouri Public Service Commission
Case No. ER-2010-0356 (MPS)

Summary Results of Staff's Revenue Neutral CCOS Study - MPS

Customer Class/Rate Schedule	CCOS % Increase	Less: System Average	Revenue Neutral % Increase
RESIDENTIAL			
Regular	4.80%	-1.02%	3.78%
Space Heating	1.33%	-1.02%	0.31%
Other	-37.30%	-1.02%	-38.31%
SMALL GENERAL SERVICE			
Primary and Secondary	-5.52%	-1.02%	-6.54%
ND (non demand)	-17.29%	-1.02%	-18.31%
Short Term without Demand	-23.47%	-1.02%	-24.49%
LARGE GENERAL SERVICE			
Primary	0.17%	-1.02%	-0.85%
Secondary	-2.63%	-1.02%	-3.65%
LARGE POWER SERVICE			
Primary	3.96%	-1.02%	2.94%
Secondary	-0.56%	-1.02%	-1.57%
LIGHTING	17.13%	-1.02%	16.11%
TOTAL	1.02%	-1.02%	0.00%

Missouri Public Service Commission
Case No. ER-2010-0356 (L&P)

Summary Results of Staff's Revenue Neutral CCOS Study - L&P			
Customer Class/Rate Schedule	**CCOS % Increase**	**Less: System Average**	**Revenue Neutral % Increase**
RESIDENTIAL			
Regular	23.85%	-21.86%	1.99%
Other	44.82%	-21.86%	22.95%
Space Heating	28.51%	-21.86%	6.64%
GENERAL SERVICE			
General Use	-8.27%	-21.86%	-30.13%
Limited Demand, Short Term, Separate Mtr. SH/WH	-16.40%	-21.86%	-38.26%
LARGE GENERAL SERVICE			
Primary, Secondary, and Substation (1 rate schedule)	14.82%	-21.86%	-7.04%
LARGE POWER SERVICE			
TOU - Primary, Secondary, Substation, Transmission (1 rate schedule)	28.77%	-21.86%	6.91%
LIGHTING - All	18.71%	-21.86%	-3.15%
TOTAL	21.86%	-21.86%	0.00%

Missouri Public Service commission
Case No. ER-2010-0356
Summary of Functions and Allocation Methods in CCOS Study

Function	Allocation to Rate Schedules
Production Plant and Reserve	
Base	Annual kWh usage @ genration for each rate schedule
Intermediate	12 NCP Average less Base
Peak	4 NCP remaining less Base and Intermediate

Transmission Plant and Reserve	12 CP Average

Distribution Plant and Reserve	
Substations	NCP
Primary	NCP
Secondary	NCP and customer maximum demands
Line Transformers	NCP and customer maximum demands
Services	KCPL assignment
Meters	KCPL assignment
General and Intangible Plant and Reserve	Functional separation of Production, Transmission and Distribution Plant

Expenses	
Production	
Fuel	Fuel cost by plant based on Base, Intermediate and Peak Plants
Other	Fixed & Variable based on NARUC Manual
Maintenance	Fixed and Variable based on NARUC Manual
Transmission	12 CP Average
Distribution	NCP, customer maximums 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 CP Average
Distribution	NCP
General and Intangible	Functional separation of Production, Transmission and Distribution Plant
Other O&M Expenses	Follows plant allocation

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

Schedule MSS-5

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FUEL ADJUSTMENT CLAUSE ELECTRIC
(Applicable to Service Provided Prior to June 4, 2011)

DEFINITIONS

ACCUMULATION PERIODS, FILING DATES AND RECOVERY PERIODS:

The two six-month accumulation periods each year through August 5, 2013, the two corresponding twelve-month recovery periods and the filing dates will be as shown below. Each filing shall include detailed work papers in electronic format to support the filing.

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

A recovery period consists of the 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.

COSTS AND REVENUES:

Costs eligible for the Fuel Adjustment Clause (FAC) will be the Company’s allocated Jurisdictional costs for the fuel component of the Company’s generating units, including costs associated with the Company’s fuel hedging program; purchased power energy charges, including applicable transmission fees; applicable Southwest Power Pool (SPP) costs, and emission allowance costs - all as incurred during the accumulation period. These costs will be offset by off-system sales revenues, applicable net SPP revenues, and any emission allowance revenues collected during the accumulation period. Eligible costs do not include the purchased power demand costs associated with purchased power contacts in excess of one year.

APPLICABILITY

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

The CAF is the result of dividing the Fuel and Purchased Power Adjustment (FPA) by forecasted retail net system input (RNSI) during the recovery period, rounded to the nearest $.0001, and aggregating over two accumulation periods. A CAF will appear on a separate line on retail customers’ bills and represents the rate charged to customers to recover the FPA.

FUEL ADJUSTMENT CLAUSE (CONTINUED)
ELECTRIC
(Applicable to Service Provided Prior to June 4, 2011)

FORMULAS AND DEFINITIONS OF COMPONENTS

FPA = 95% * ((TEC – B) * J) + C + I

CAF = FPA/RNSI

Single Accumulation Period Secondary Voltage CAF_{Sec} = CAF * XF_{Sec}

Single Accumulation Period Primary Voltage CAF_{Prim} = CAF * XF_{Prim}

Annual Secondary Voltage CAF =
Aggregation of the Single Accumulation Period Secondary Voltage CAFs still to be recovered

Annual Primary Voltage CAF =
Aggregation of the Single Accumulation Period Primary Voltage CAFs still to be recovered

Where:

FPA = Fuel and Purchased Power Adjustment

CAF = Cost Adjustment Factor

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

TEC = Total Energy Cost = (FC + EC + PP - OSSR):

FC = Fuel Costs Incurred to Support Sales:

- The following costs reflected in Federal Energy Regulatory Commission (FERC) Account Numbers 501 & 502: coal commodity and railroad transportation, switching and demurrage charges, applicable taxes, natural gas costs, alternative fuel (i.e. tires and bio-fuel), fuel additives, quality adjustments assessed by coal suppliers, fuel hedging cost (hedging is defined as realized losses and cost minus realized gains associated with mitigating volatility in the Company's cost of fuel, including but not limited to, the Company's use of futures, options and over-the-counter derivatives including, without limitation, futures contracts, puts, calls, caps, floors, collars, and swaps), fuel oil adjustments included in commodity and transportation costs, broker commissions and fees associated with price hedges, oil costs, ash disposal revenues and expenses, fuel used for fuel handling, and settlement proceeds, insurance recoveries, subrogation recoveries for increased fuel expenses in Account 501.

FUEL ADJUSTMENT CLAUSE (CONTINUED)
ELECTRIC
(Applicable to Service Provided Prior to June 4, 2011)

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

EC = Net Emissions Costs:

- The following costs reflected in FERC Account Number 509 or any other account FERC may designate for emissions expenses in the future: Emission allowances costs and revenues from the sale of SO2 emission allowances.

PP = Purchased Power Costs:

- Purchased power costs reflected in FERC Account Numbers 555, 565, and 575: Purchased power costs, settlement proceeds, insurance recoveries, and subrogation recoveries for increased purchased power expenses in Account 555, excluding SPP and MISO administrative fees and excluding capacity charges for purchased power contracts with terms in excess of one (1) year.

OSSR = Revenues from Off-System Sales:

- Revenues from Off-system Sales shall exclude long-term full & partial requirements sales associated with GMO.

B = Base energy costs are costs as defined in the description of TEC (Total Energy Cost). Base Energy costs will be calculated as shown below:
L&P NSI x Applicable Base Energy Cost
MPS NSI x Applicable Base Energy Cost

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

C = Under / Over recovery determined in the true-up of prior recovery period cost, including accumulated interest, and modifications due to prudence reviews

I = Interest on deferred electric energy costs calculated at a rate equal to the weighted average interest paid on short-term debt applied to the month-end balance of deferred electric energy costs

FUEL ADJUSTMENT CLAUSE (CONTINUED)
ELECTRIC
(Applicable to Service Provided Prior to June 4, 2011)

RNSI = Forecasted retail net system input in kWh for the Recovery Period

XF = Expansion factor by voltage level

XF_{Sec} = Expansion factor for lower than primary voltage customers
XF_{Prim} = Expansion factor for primary and higher voltage customers

NSI = Net system input (kWh) for the accumulation period

The FPA will be calculated separately for L&P and MPS, and by voltage level, and the resultant CAF's will be applied to customers in the respective divisions and voltage levels.

APPLICABLE BASE ENERGY COST

Company base energy costs per kWh:
$0.01642 for L&P.
$0.02348 for MPS

TRUE-UPS AND PRUDENCE REVIEWS

There shall be prudence reviews of costs and the true-up of revenues collected with costs intended for collection. FAC costs collected in rates will be refundable based on true-up results and findings in regard to prudence. 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. True-ups occur at the end of each recovery period. Prudence reviews shall occur no less frequently than at 18 month intervals.

STATE OF MISSOURI, PUBLIC SERVICE COMMISSION
P.S.C. MO. No. 1 Original Sheet No. 126.4
Canceling P.S.C. MO. No. Sheet No.
KCP&L Greater Missouri Operations Company For Territories Served as L&P and MPS
KANSAS CITY, MO

FUEL ADJUSTMENT CLAUSE (CONTINUED)
ELECTRIC
(Applicable to Service Provided Prior to June 4, 2011)

COST ADJUSTMENT FACTOR

		MPS	L&P
Accumulation Period Ending		5/31/10	5/31/10
1 Total Energy Cost (TEC)		$90,226,379	$22,334,031
2 Base energy cost (B)	-	$74,249,464	$19,644,937
3 First Interim Total		$15,976,915	$2,689,094
4 Jurisdictional Factor (J)	*	99.448%	100%
5 Second Interim Total		$15,888,721	$2,689,094
6 Customer Responsibility	*	95%	95%
7 Third Interim Total		$15,094,285	$2,554,639
8 Adjustment for Under / Over recovery for prior periods and Modifications due to prudence reviews (C)	+	$768,873	$377,151
9 Interest (I)	+	$421,355	$41,847
10 Fuel and Purchased Power Adjustment (FPA)		$16,284,513	$2,973,638
11 RNSI	÷	6,358,211,651	2,254,414,809
12 Fourth Interim Total		$0.0026	$0.0013
13 Current period CAF_{Prim} (= Line 12 * XF_{Prim})		$0.0027	$0.0014
14 Previous period CAF_{Prim}	+	$0.0038	$0.0008
15 Current annual CAF_{Prim}		$0.0065	$0.0022
16 Current period CAF_{Sec} (= Line 12 * XF_{Sec})		$0.0027	$0.0014
17 Previous period CAF_{Sec}	+	$0.0038	$0.0008
18 Current annual CAF_{Sec}		$0.0065	$0.0022

Expansion Factors (XF):

Network:	Primary	Secondary
MPS	1.0444	1.0679
L&P	1.0444	1.0700

Issued: Effective: June 4, 2011
Issued by: Curtis D. Blanc, Sr. Director

FUEL ADJUSTMENT CLAUSE ELECTRIC
(Applicable to Service Provided June 4, 2011 and Thereafter)

DEFINITIONS

ACCUMULATION PERIODS, FILING DATES AND RECOVERY PERIODS:

The two six-month accumulation periods each year through November 30, 2014, the two corresponding twelve-month recovery periods and the filing dates will be as shown below. Each filing shall include detailed work papers in electronic format to support the filing.

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

A recovery period consists of the 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.

COSTS AND REVENUES:

Costs eligible for the Fuel Adjustment Clause (FAC) will be the Company's allocated Jurisdictional costs for the fuel component of the Company's generating units, including costs associated with the Company's fuel hedging program; purchased power energy charges, including applicable transmission fees; and emission allowance costs - all as incurred during the accumulation period. These costs will be offset by off-system sales revenues, and any emission allowance revenues collected during the accumulation period. Eligible costs do not include the purchased power demand costs associated with purchased power contacts in excess of one year.

APPLICABILITY

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

The CAF is the result of dividing the Fuel and Purchased Power Adjustment (FPA) by forecasted retail net system input (RNSI) during the recovery period, rounded to the nearest $.0001, and aggregating over two accumulation periods. A CAF will appear on a separate line on retail customers' bills and represents the rate charged to customers to recover the FPA.

FUEL ADJUSTMENT CLAUSE (CONTINUED)
ELECTRIC
(Applicable to Service Provided June 4, 2011 and Thereafter)

FORMULAS AND DEFINITIONS OF COMPONENTS

FPA = 75% * (TEC – B - CGP) + C + I

CAF = FPA/RNSI

Single Accumulation Period Secondary Voltage CAF_{Sec} = CAF * XF_{Sec}

Single Accumulation Period Primary Voltage CAF_{Prim} = CAF * XF_{Prim}

Annual Secondary Voltage CAF =
Aggregation of the Single Accumulation Period Secondary Voltage CAFs still to be recovered

Annual Primary Voltage CAF =
Aggregation of the Single Accumulation Period Primary Voltage CAFs still to be recovered

Where:

FPA = Fuel and Purchased Power Adjustment

CAF = Cost Adjustment Factor

75% = Customer responsibility for fuel variance from base level.

TEC = Total Energy Cost = (FC + EC + PP - OSSR):

FC = Fuel Costs Incurred to Support Sales:

- The following costs reflected in Federal Energy Regulatory Commission (FERC) Account Numbers 501 & 502: coal commodity and railroad transportation, switching and demurrage charges, applicable taxes, natural gas costs, alternative fuel (i.e. tires and bio-fuel), fuel additives, quality adjustments assessed by coal suppliers, fuel hedging cost (hedging is defined as realized losses and cost minus realized gains associated with mitigating volatility in the Company's cost of fuel, including but not limited to, the Company's use of futures, options and over-the-counter derivatives including, without limitation, futures contracts, puts, calls, caps, floors, collars, and swaps), fuel oil adjustments included in commodity and transportation costs, broker commissions and fees associated with price hedges, oil costs, propane costs, ash disposal revenues and expenses, fuel used for fuel handling, and settlement proceeds, insurance recoveries, subrogation recoveries for increased fuel expenses in Account 501.

FUEL ADJUSTMENT CLAUSE (CONTINUED)
ELECTRIC
(Applicable to Service Provided June 4, 2011 and Thereafter)

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

EC = Net Emissions Costs:

- The following costs reflected in FERC Account Number 509 or any other account FERC may designate for emissions expenses in the future: Emission allowances costs and revenues from the sale of SO2 emission allowances.

PP = Purchased Power Costs:

- Purchased power costs reflected in FERC Account Numbers 555: Purchased power costs, settlement proceeds, insurance recoveries, and subrogation recoveries for increased purchased power expenses in Account 555, and excluding capacity charges for purchased power contracts with terms in excess of one (1) year.

OSSR = Revenues from Off-System Sales:

- Revenues from Off-system Sales shall exclude long-term full and partial requirements sales to Missouri municipalities that are associated with GMO.

B = Base energy costs are costs as defined in the description of TEC (Total Energy Cost). Base Energy costs will be calculated as shown below:

L&P NSI x Applicable Base Energy Cost
MPS NSI x Applicable Base Energy Cost

CGP = Accumulation period Crossroads Generating Plant factor will be used to reduce actual fuel costs to reflect one-half of the estimated annual incremental cost to include the Crossroads Generating Plant in the FAC. For each accumulation period, the CGP factor is equal to $370,035 for MPS and $0 for L&P.

C = Under / Over recovery determined in the true-up of prior recovery period cost, including accumulated interest, and modifications due to prudence reviews.

I = Interest on deferred electric energy costs calculated at a rate equal to the weighted average interest paid on short-term debt applied to the month-end balance of deferred electric energy costs.

FUEL ADJUSTMENT CLAUSE (CONTINUED)
ELECTRIC
(Applicable to Service June 4, 2011 and Thereafter)

RNSI = Forecasted recovery period net system input in kWh, at the generator

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

NSI = Net system input (kWh) for the accumulation period

The FPA will be calculated separately for L&P and MPS, and by voltage level, and the resultant CAF's will be applied to customers in the respective divisions and voltage levels.

APPLICABLE BASE ENERGY COST

Base Energy Cost in this FAC is equal to the Base Energy Cost in the test year revenue requirement for this general rate case. The Base Energy Costs per kWh for MPS and for L&P are:

$0.0199 per kWh for L&P
$0.0250 per kWh for MPS

TRUE-UPS AND PRUDENCE REVIEWS

There shall be prudence reviews of costs and the true-up of revenues collected with costs intended for collection. FAC costs collected in rates will be refundable based on true-up results and findings in regard to prudence. 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. True-ups occur at the end of each recovery period. Prudence reviews shall occur no less frequently than at 18 month intervals.

FUEL ADJUSTMENT CLAUSE (CONTINUED)
ELECTRIC
(Applicable to Service Provided June 4, 2011 and Thereafter)

COST ADJUSTMENT FACTOR

		MPS	L&P
Accumulation Period Ending			
1 Total Energy Cost (TEC)			
2 Base energy cost (B)	-		
3 Crossroads Generating Plant (CGP)	-	$370,035	$0
4 First Interim Total			
5 Customer Responsibility	*	75%	75%
6 Second Interim Total			
7 Adjustment for Under / Over recovery for prior periods and Modifications due to prudence reviews (C)	+		
8 Interest (I)	+		
9 Fuel and Purchased Power Adjustment (FPA)			
10 RNSI	÷		
11 Third Interim Total			
12 Current period CAF_{Prim} (= Line 12 * XF_{Prim})			
13 Previous period CAF_{Prim}	+		
14 Current annual CAF_{Prim}			
15 Current period CAF_{Sec} (= Line 12 * XF_{Sec})			
16 Previous period CAF_{Sec}	+		
17 Current annual CAF_{Sec}			

Expansion Factors (XF):

Network:	Primary	Secondary
MPS	1.0419	1.0712
L&P	1.0421	1.0701

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STATE OF MISSOURI, PUBLIC SERVICE COMMISSION

P.S.C. MO. No.	1	~~1st~~ 2nd	Revised Sheet No. 124
Canceling P.S.C. MO. No.	1	~~1st~~	~~Original~~ Revised Sheet No. 124

KCP&L Greater Missouri Operations Company For Territories Served as L&P and MPS

KANSAS CITY, MO ~~64106~~

~~FUEL ADJUSTMENT CLAUSE ELECTRIC~~

~~(Applicable to Service Provided Prior to September 1, 2009)~~

~~DEFINITIONS~~

~~ACCUMULATION PERIOD:~~

~~The two six-month accumulation periods each year through May 31, 2011, the two corresponding twelve-month recovery periods and filing dates will be as follows:~~

~~**Accumulation Period**~~	~~**Filing Date**~~	~~**Recovery Period**~~
~~June – November~~	~~By January 1~~	~~March – February~~
~~December – May~~	~~By July 1~~	~~September – August~~

~~RECOVERY PERIOD:~~

~~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.~~

~~COSTS:~~

~~Costs eligible for Fuel Adjustment Clause (FAC) will be the Company's allocated variable Missouri Jurisdictional costs for the fuel component of the Company's generating units, purchased power energy charges, and emission allowance costs. Eligible costs do not include the purchased power demand costs associated with purchased power contracts.~~

~~APPLICATION~~

~~The price per kWh of electricity sold will be adjusted subject to application of the FAC mechanism and approval by the Missouri Public Service Commission. The price will reflect accumulation period Missouri Jurisdictional costs above or below base costs for:~~

1. ~~variable fuel components related to the Company's electric generating plants;~~
2. ~~purchased power energy charges;~~
3. ~~emission allowance costs;~~
4. ~~an adjustment for recovery period sales variation. This is based on the difference between the values of the FAC as adjusted minus actual FAC revenue during the recovery period. This amount will be collected or refunded during a succeeding recovery period;~~
5. ~~interest on deferred electric energy costs, which shall be determined monthly. Interest shall be calculated at a rate equal to the weighted average interest rate paid on short-term debt, applied to the month-end balance of deferred electric energy costs. The accumulated interest shall be included in the determination of the CAF.~~

~~The FAC will be the aggregation of (1), (2), (3), minus the base cost of fuel, all times 95%, plus or minus (4), plus (5), above.~~

~~The Cost Adjustment Factor is the result of dividing the FAC by estimated kWh sales during the recovery period, rounded to the nearest $.0001, and aggregating over two accumulation periods. The formula and components are displayed below.~~

~~Issued: July 8, 2009~~ ~~Effective: September 1, 2009~~
~~Issued by: Curtis D. Blanc, Sr. Director~~
~~STATE OF MISSOURI, PUBLIC SERVICE COMMISSION~~

~~P.S.C. MO. No.~~	~~1~~	~~1st~~	~~Revised Sheet No. 125~~
~~Canceling P.S.C. MO. No.~~	~~1~~		~~Original Sheet No. 125~~

~~**KCP&L Greater Missouri Operations Company**~~ ~~For Territories Served as L&P and MPS~~
~~**KANSAS CITY, MO 64106**~~

~~FUEL ADJUSTMENT CLAUSE (CONTINUED)~~
~~ELECTRIC~~
~~(Applicable to Service Provided Prior to September 1, 2009)~~

$$\cancel{FAC_{Sec} = \{[95\% * (F + P + E - B)] * \{(S_{ASec} * L_{Sec}) / [(S_{ASec} * L_{Sec}) + (S_{APrim} * L_{Prim})]\}\} + C_{Sec}}$$

$$\cancel{FAC_{Prim} = \{[95\% * (F + P + E - B)] * \{(S_{APrim} * L_{Prim}) / [(S_{ASec} * L_{Sec}) + (S_{APrim} * L_{Prim})]\}\} + C_{Prim}}$$

~~The Cost Adjustment Factor (CAF) is as follows:~~

~~Single Accumulation Period Secondary Voltage CAF = FAC_{Sec} / S_{RSec}~~

~~Single Accumulation Period Primary Voltage CAF = FAC_{Prim} / S_{RPrim}~~

~~Annual Secondary Voltage CAF =~~
~~Aggregation of the Single Accumulation Period Secondary Voltage CAFs still to be recovered~~

~~Annual Primary Voltage CAF =~~
~~Aggregation of the Single Accumulation Period Primary Voltage CAFs still to be recovered~~

~~Where:~~
~~FAC_{Sec} = Secondary Voltage FAC~~
~~FAC_{Prim} = Primary Voltage FAC~~
~~95% = Customer responsibility for fuel variance from base level~~
~~F = Actual variable cost of fuel in FERC Accounts 501 & 547~~
~~P = Actual cost of purchased energy in FERC Account 555~~
~~E = Actual emission allowance cost in FERC Account 509~~
~~B = Base variable fuel costs, purchased energy, and emission allowances are calculated as shown below:~~
~~L&P S_A x $0.01799~~
~~MPS S_A x $0.02538~~
~~C = Under / Over recovery determined in the true-up of prior recovery period cost, including accumulated interest, and modifications due to prudence reviews~~
~~C_{Sec} = Lower than Primary Voltage Customers~~
~~C_{Prim} = Primary and Higher Voltage Customers~~
~~S_A = Actual sales (kWh) for the accumulation period~~
~~S_{ASec} = Lower than Primary Voltage Customers~~
~~S_{APrim} = Primary and Higher Voltage Customers~~
~~S_R = Estimated sales (kWh) for the recovery period~~
~~S_{RSec} = Lower than Primary Voltage Customers~~
~~S_{RPrim} = Primary and Higher Voltage Customers~~
~~L = Loss factor by voltage level~~
~~L_{Sec} = Lower than Primary Customers~~
~~L_{Prim} = Primary and Higher Customers~~

~~FUEL ADJUSTMENT CLAUSE (CONTINUED)~~
ELECTRIC
~~(Applicable to Service Provided Prior to September 1, 2009)~~

~~The FAC will be calculated separately for KCP&L Greater Missouri Operations Company - L&P and KCP&L Greater Missouri Operations Company - MPS and by voltage level, and the resultant CAF's will be applied to customers in the respective divisions and voltage levels.~~

~~APPLICABLE BASE ENERGY COST~~

~~Company base energy cost per kWh sold, $0.01799 for L&P, and $0.02538 for MPS. These base energy costs are to be used for the calculations of the over/under accumulation up until the effective date of this tariff.~~

~~TRUE-UPS AND PRUDENCE REVIEWS~~

~~There shall be prudence reviews of costs and the true-up of revenues collected with costs intended for collection. FAC costs collected in rates will be refundable based on true-up results and findings in regard to prudence. 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. True-ups occur at the end of each recovery period. Prudence reviews shall occur no less frequently than at 18 month intervals.~~

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Issued: ~~July 8, 2009~~ Effective: ~~September 1, 2009~~ June 4, 2011
Issued by: Curtis D. Blanc, Sr. Director

STATE OF MISSOURI, PUBLIC SERVICE COMMISSION
P.S.C. MO. No. 1 ~~4th~~ 2nd Revised Sheet No. ~~127~~ 125
Canceling P.S.C. MO. No. 1 ~~3rd~~ 1st Revised Sheet No. ~~127~~ 125
KCP&L Greater Missouri Operations Company
~~**(for all territories formerly served by Aquila Networks, Inc.**~~ For Territories Served as L&P and MPS~~)~~
KANSAS CITY, MO ~~**64106**~~

~~FUEL ADJUSTMENT CLAUSE (CONTINUED)~~
ELECTRIC

~~COST ADJUSTMENT FACTOR~~

~~**Aquila Networks – L&P**~~		~~Total~~		~~Secondary~~		~~Primary~~
~~Accumulation Period Ending~~		~~05/31/09~~				
~~1 Total energy cost (F, P, and E)~~		~~$20,625,370~~				
~~2 Base energy cost (B)~~	-	~~$19,859,094~~				
~~3 First Interim Total~~		~~$766,276~~				
~~4 Base energy (S_A) by voltage level~~				~~955,322,554~~		~~148,573,718~~
~~4.1 Loss factors (L)~~			~~*~~	~~108.443%~~	~~*~~	~~106.231%~~
~~4.2 S_A adjusted for losses~~				~~1,035,982,044~~		~~157,831,817~~
~~4.3 Loss factor weights~~			~~*~~	~~86.779%~~	~~*~~	~~13.221%~~
~~5 Customer Responsibility~~	~~*~~	~~95%~~				
~~6 Second Interim Total by voltage level~~		~~$727,962~~		~~$631,720~~		~~$96,242~~
~~7 Adjustment for Under / Over recovery for prior periods (C)~~			~~±~~	~~$9,412~~	~~±~~	~~$1,434~~
~~8 Fuel Adjustment Clause~~				~~$808,160~~		~~$123,123~~
~~9 Estimated recovery period sales kWh (S_R)~~			~~÷~~	~~1,843,670,186~~	~~÷~~	~~286,731,359~~
~~10 Current period cost adjustment factor~~				~~$0.0004~~		~~$0.0004~~
~~11 Previous period cost adjustment factor~~			~~+~~	~~$0.0028~~	~~+~~	~~$0.0028~~
~~12 Current annual cost adjustment factor~~				~~$0.0032~~		~~$0.0032~~

~~**Aquila Networks – MPS**~~		~~Total~~		~~Secondary~~		~~Primary~~
~~Accumulation Period Ending~~		~~05/31/09~~				
~~1 Total energy cost (F, P, and E)~~		~~$92,813,847~~				
~~2 Base energy cost (B)~~	-	~~$73,113,231~~				
~~3 First Interim Total~~		~~$19,700,616~~				
~~4 Base energy (S_A) by voltage level~~				~~2,522,005,024~~		~~358,736,927~~
~~4.1 Loss factors (L)~~			~~*~~	~~107.433%~~	~~*~~	~~104.187%~~
~~4.2 S_A adjusted for losses~~				~~2,709,464,763~~		~~373,757,104~~
~~4.3 Loss factor weights~~			~~*~~	~~87.878%~~	~~*~~	~~12.122%~~
~~5 Customer Responsibility~~	~~*~~	~~95%~~				
~~6 Second Interim Total by voltage level~~		~~$18,715,586~~		~~$16,446,828~~		~~$2,268,758~~
~~7 Adjustment for Under / Over recovery for prior periods (C)~~			~~±~~	~~$384,524~~	~~±~~	~~$53,043~~
~~8 Fuel Adjustment Clause~~				~~$17,238,328~~		~~$2,377,941~~
~~9 Estimated recovery period sales kWh (S_R)~~			~~÷~~	~~5,189,369,412~~	~~÷~~	~~738,150,170~~
~~10 Current period cost adjustment factor~~				~~$0.0033~~		~~$0.0032~~
~~11 Previous period cost adjustment factor~~			~~+~~	~~$0.0031~~	~~+~~	~~$0.0030~~
~~12 Current annual cost adjustment factor~~				~~$0.0064~~		~~$0.0062~~

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Issued: ~~July 1, 2009~~ Effective: ~~September 1, 2009~~June 4, 2011
Issued by: ~~Tim Rush, Regulatory Affairs~~Curtis D. Blanc, Sr. Director

STATE OF MISSOURI, PUBLIC SERVICE COMMISSION
P.S.C. MO. No. 1 ~~Original~~2nd Revised Sheet No. ~~127.1~~126
Canceling P.S.C. MO. No. 1 1st Revised Sheet No. 126
KCP&L Greater Missouri Operations Company For Territories Served as L&P and MPS
KANSAS CITY, MO ~~64106~~

FUEL ADJUSTMENT CLAUSE ELECTRIC
(Applicable to Service Provided ~~September 1, 2009 and Thereafter~~Prior to June 4, 2011)

DEFINITIONS

Schedule JAR-2-7

ACCUMULATION PERIODS, FILING DATES AND RECOVERY PERIODS:

The two six-month accumulation periods each year through August 5, 2013, the two corresponding twelve-month recovery periods and the filing dates will be as shown below. Each filing shall include detailed work papers in electronic format to support the filing.

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

A recovery period consists of the 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.

COSTS AND REVENUES:

Costs eligible for the Fuel Adjustment Clause (FAC) will be the Company's allocated Jurisdictional costs for the fuel component of the Company's generating units, including costs associated with the Company's fuel hedging program; purchased power energy charges, including applicable transmission fees; applicable Southwest Power Pool (SPP) costs, and emission allowance costs - all as incurred during the accumulation period. These costs will be offset by off-system sales revenues, applicable net SPP revenues, and any emission allowance revenues collected during the accumulation period. Eligible costs do not include the purchased power demand costs associated with purchased power contacts in excess of one year.

APPLICABILITY

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

The CAF is the result of dividing the Fuel and Purchased Power Adjustment (FPA) by forecasted retail net system input (RNSI) during the recovery period, rounded to the nearest $.0001, and aggregating over two accumulation periods. A CAF will appear on a separate line on retail customers' bills and represents the rate charged to customers to recover the FPA.

FORMULAS AND DEFINITIONS OF COMPONENTS

FPA = 95% * ((TEC – B) * J) + C + I

CAF = FPA/RNSI

Single Accumulation Period Secondary Voltage CAF_{Sec} = CAF * XF_{Sec}

Single Accumulation Period Primary Voltage CAF_{Prim} = CAF * XF_{Prim}

Annual Secondary Voltage CAF =
Aggregation of the Single Accumulation Period Secondary Voltage CAFs still to be recovered

Annual Primary Voltage CAF =
Aggregation of the Single Accumulation Period Primary Voltage CAFs still to be recovered

Where:

FPA = Fuel and Purchased Power Adjustment

CAF = Cost Adjustment Factor

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

TEC = Total Energy Cost = (FC + EC + PP - OSSR):

FC = Fuel Costs Incurred to Support Sales:

- The following costs reflected in Federal Energy Regulatory Commission (FERC) Account Numbers 501 & 502: coal commodity and railroad transportation, switching and demurrage charges, applicable taxes, natural gas costs, alternative fuel (i.e. tires and bio-fuel), fuel additives, quality adjustments assessed by coal suppliers, fuel hedging cost (hedging is defined as realized losses and cost minus realized gains associated with mitigating volatility in the Company's cost of fuel, including but not limited to, the Company's use of futures, options and over-the-counter derivatives including, without limitation, futures contracts, puts, calls, caps, floors, collars, and swaps), fuel oil adjustments included in commodity and transportation costs, broker commissions and fees associated with price hedges, oil costs, ash disposal revenues and expenses, fuel used for fuel handling, and settlement proceeds, insurance recoveries, subrogation recoveries for increased fuel expenses in Account 501.

FUEL ADJUSTMENT CLAUSE (CONTINUED)
ELECTRIC
(Applicable to Service Provided ~~September 1, 2009 and Thereafter~~Prior to June 4, 2011)

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

EC = Net Emissions Costs:

- The following costs reflected in FERC Account Number 509 or any other account FERC may designate for emissions expenses in the future: Emission allowances costs and revenues from the sale of SO2 emission allowances.

PP = Purchased Power Costs:

- Purchased power costs reflected in FERC Account Numbers 555, 565, and 575: Purchased power costs, settlement proceeds, insurance recoveries, and subrogation recoveries for increased purchased power expenses in Account 555, excluding SPP and MISO administrative fees and excluding capacity charges for purchased power contracts with terms in excess of one (1) year.

OSSR = Revenues from Off-System Sales:

- Revenues from Off-system Sales shall exclude long-term full & partial requirements sales associated with GMO.

B = Base energy costs are costs as defined in the description of TEC (Total Energy Cost). Base Energy costs will be calculated as shown below:
L&P NSI x Applicable Base Energy Cost
MPS NSI x Applicable Base Energy Cost

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

C = Under / Over recovery determined in the true-up of prior recovery period cost, including accumulated interest, and modifications due to prudence reviews

I = Interest on deferred electric energy costs calculated at a rate equal to the weighted average interest paid on short-term debt applied to the month-end balance of deferred electric energy costs

FUEL ADJUSTMENT CLAUSE (CONTINUED)
ELECTRIC
(Applicable to Service Provided ~~September 1, 2009 and Thereafter~~Prior to June 4, 2011)

RNSI = Forecasted retail net system input in kWh for the Recovery Period

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

NSI = Net system input (kWh) for the accumulation period

The FPA will be calculated separately for L&P and MPS, and by voltage level, and the resultant CAF's will be applied to customers in the respective divisions and voltage levels.

APPLICABLE BASE ENERGY COST

Company base energy costs per kWh:
$0.01642 for L&P.
$0.02348 for MPS

TRUE-UPS AND PRUDENCE REVIEWS

There shall be prudence reviews of costs and the true-up of revenues collected with costs intended for collection. FAC costs collected in rates will be refundable based on true-up results and findings in regard to prudence. 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. True-ups occur at the end of each recovery period. Prudence reviews shall occur no less frequently than at 18 month intervals.

Issued: ~~July 8, 2009~~ Effective: ~~September 1, 2009~~June 4, 2011
Issued by: Curtis D. Blanc, Sr. Director

STATE OF MISSOURI, PUBLIC SERVICE COMMISSION
P.S.C. MO. No. 1 ~~2nd Revised~~ Original Sheet No. ~~127.5~~126.4
Canceling P.S.C. MO. No. ~~1~~ ~~1st~~ ~~Revised~~ Sheet No. ~~127.5~~
KCP&L Greater Missouri Operations Company For Territories Served as L&P and MPS
KANSAS CITY, MO ~~64106~~

FUEL ADJUSTMENT CLAUSE (CONTINUED)
ELECTRIC
(Applicable to Service Provided ~~September 1, 2009 and Thereafter~~Prior to June 4, 2011)

COST ADJUSTMENT FACTOR

			MPS	L&P
	Accumulation Period Ending		5/31/10	5/31/10
1	Total Energy Cost (TEC)		$90,226,379	$22,334,031
2	Base energy cost (B)	-	$74,249,464	$19,644,937
3	First Interim Total		$15,976,915	$2,689,094
4	Jurisdictional Factor (J)	*	99.448%	100%
5	Second Interim Total		$15,888,721	$2,689,094
6	Customer Responsibility	*	95%	95%
7	Third Interim Total		$15,094,285	$2,554,639
8	Adjustment for Under / Over recovery for prior periods and Modifications due to prudence reviews (C)	+	$768,873	$377,151
9	Interest (I)	+	$421,355	$41,847
10	Fuel and Purchased Power Adjustment (FPA)		$16,284,513	$2,973,638
11	RNSI	÷	6,358,211,651	2,254,414,809
12	Fourth Interim Total		$0.0026	$0.0013
13	Current period CAF_{Prim} (= Line 12 * XF_{Prim})		$0.0027	$0.0014
14	Previous period CAF_{Prim}	+	$0.0038	$0.0008
15	Current annual CAF_{Prim}		$0.0065	$0.0022
16	Current period CAF_{Sec} (= Line 12 * XF_{Sec})		$0.0027	$0.0014
17	Previous period CAF_{Sec}	+	$0.0038	$0.0008
18	Current annual CAF_{Sec}		$0.0065	$0.0022

Expansion Factors (XF):

Network:	Primary	Secondary
MPS	1.0444	1.0679
L&P	1.0444	1.0700

FUEL ADJUSTMENT CLAUSE ELECTRIC
(Applicable to Service Provided June 4, 2011~~September 1, 2009~~ and Thereafter)

DEFINITIONS

ACCUMULATION PERIODS, FILING DATES AND RECOVERY PERIODS:

The two six-month accumulation periods each year through November 30, 2014~~August 5, 2013~~, the two corresponding twelve-month recovery periods and the filing dates will be as shown below. Each filing shall include detailed work papers in electronic format to support the filing.

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

A recovery period consists of the 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.

COSTS AND REVENUES:

Costs eligible for the Fuel Adjustment Clause (FAC) will be the Company's allocated Jurisdictional costs for the fuel component of the Company's generating units, including costs associated with the Company's fuel hedging program; purchased power energy charges, including applicable transmission fees;~~ applicable Southwest Power Pool (SPP) costs,~~ and emission allowance costs - all as incurred during the accumulation period. These costs will be offset by off-system sales revenues,~~ applicable net SPP revenues,~~ and any emission allowance revenues collected during the accumulation period. Eligible costs do not include the purchased power demand costs associated with purchased power contacts in excess of one year.

APPLICABILITY

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

The CAF is the result of dividing the Fuel and Purchased Power Adjustment (FPA) by forecasted retail net system input (RNSI) during the recovery period, rounded to the nearest $.0001, and aggregating over two accumulation periods. A CAF will appear on a separate line on retail customers' bills and represents the rate charged to customers to recover the FPA.

FUEL ADJUSTMENT CLAUSE (CONTINUED)
ELECTRIC
(Applicable to Service Provided June 4, 2011~~September 1, 2009~~ and Thereafter)

FORMULAS AND DEFINITIONS OF COMPONENTS

FPA = 75~~95~~% * ((TEC – B - CGP) * J) + C + I

CAF = FPA/RNSI

Single Accumulation Period Secondary Voltage CAF_{Sec} = CAF * XF_{Sec}

Single Accumulation Period Primary Voltage CAF_{Prim} = CAF * XF_{Prim}

Annual Secondary Voltage CAF =
Aggregation of the Single Accumulation Period Secondary Voltage CAFs still to be recovered

Annual Primary Voltage CAF =
Aggregation of the Single Accumulation Period Primary Voltage CAFs still to be recovered

Where:

FPA = Fuel and Purchased Power Adjustment

CAF = Cost Adjustment Factor

75~~95~~% = Customer responsibility for fuel variance from base level.

TEC = Total Energy Cost = (FC + EC + PP - OSSR):

FC = Fuel Costs Incurred to Support Sales:

- The following costs reflected in Federal Energy Regulatory Commission (FERC) Account Numbers 501 & 502: coal commodity and railroad transportation, switching and demurrage charges, applicable taxes, natural gas costs, alternative fuel (i.e. tires and bio-fuel), fuel additives, quality adjustments assessed by coal suppliers, fuel hedging cost (hedging is defined as realized losses and cost minus realized gains associated with mitigating volatility in the Company's cost of fuel, including but not limited to, the Company's use of futures, options and over-the-counter derivatives including, without limitation, futures contracts, puts, calls, caps, floors, collars, and swaps), fuel oil adjustments included in commodity and transportation costs, broker commissions and fees associated with price hedges, oil costs, propane costs, ash disposal revenues and expenses, fuel used for fuel handling, and settlement proceeds, insurance recoveries, subrogation recoveries for increased fuel expenses in Account 501.

FUEL ADJUSTMENT CLAUSE (CONTINUED)
ELECTRIC
(Applicable to Service Provided June 4 2011~~September 1, 2009~~ and Thereafter)

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

EC = Net Emissions Costs:

- The following costs reflected in FERC Account Number 509 or any other account FERC may designate for emissions expenses in the future: Emission allowances costs and revenues from the sale of SO2 emission allowances.

PP = Purchased Power Costs:

- Purchased power costs reflected in FERC Account Numbers 555~~, 565, and 575~~: Purchased power costs, settlement proceeds, insurance recoveries, and subrogation recoveries for increased purchased power expenses in Account 555,~~ excluding SPP and MISO administrative fees and~~ excluding capacity charges for purchased power contracts with terms in excess of one (1) year.

OSSR = Revenues from Off-System Sales:

- Revenues from Off-system Sales shall exclude long-term full and~~&~~ partial requirements sales to Missouri municipalities that are associated with GMO.

B = Base energy costs are costs as defined in the description of TEC (Total Energy Cost). Base Energy costs will be calculated as shown below:

L&P NSI x Applicable Base Energy Cost
MPS NSI x Applicable Base Energy Cost

~~J = Energy retail ratio = Retail kWh sales/total system kWh~~
~~Where: total system kWh equals retail and full and partial requirements sales associated with GMO.~~
CGP = Accumulation period Crossroads Generation Plant factor will be used to reduce actual fuel costs to reflect one-half of the estimated annual incremental cost to include the Crossroads Generating Plant in the FAC. For each accumulation period, the CGP factor is equal to $370,035 for MPS and $0 for L&P.

C = Under / Over recovery determined in the true-up of prior recovery period cost, including accumulated interest, and modifications due to prudence reviews

I = Interest on deferred electric energy costs calculated at a rate equal to the weighted average interest paid on short-term debt applied to the month-end balance of deferred electric energy costs

FUEL ADJUSTMENT CLAUSE (CONTINUED)
ELECTRIC
(Applicable to Service Provided June 4, 2011~~September 1, 2009~~ and Thereafter)

RNSI = Forecasted recovery period~~retail~~ net system input in kWh, at the generator ~~for the Recovery Period~~

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

NSI = Net system input (kWh) for the accumulation period

The FPA will be calculated separately for L&P and MPS, and by voltage level, and the resultant CAF's will be applied to customers in the respective divisions and voltage levels.

APPLICABLE BASE ENERGY COST

Base Energy Cost in this FAC is equal to the Base Energy Cost in the test year revenue requirement for this general rate case. The Base Energy Costs per kWh for MPS and for L&P are:~~Company base energy costs per kWh:~~

$0.0199~~$0.01642~~ per kWh for L&P.
$0.0250~~$0.02348~~ per kWh for MPS

TRUE-UPS AND PRUDENCE REVIEWS

There shall be prudence reviews of costs and the true-up of revenues collected with costs intended for collection. FAC costs collected in rates will be refundable based on true-up results and findings in regard to prudence. 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. True-ups occur at the end of each recovery period. Prudence reviews shall occur no less frequently than at 18 month intervals.

Issued: ~~July 8, 2009~~ Effective: June 4, 2011~~September 1, 2009~~

Issued by: Curtis D. Blanc, Sr. Director

STATE OF MISSOURI, PUBLIC SERVICE COMMISSION

P.S.C. MO. No. 1 1st~~2nd~~ Revised Sheet No. 127.4~~5~~

Canceling P.S.C. MO. No. 1 ~~1st~~ Original~~Revised~~ Sheet No. 127.4~~5~~

KCP&L Greater Missouri Operations Company For Territories Served as L&P and MPS

KANSAS CITY, MO ~~64106~~

FUEL ADJUSTMENT CLAUSE (CONTINUED)
ELECTRIC
(Applicable to Service Provided June 4, 2011~~September 1, 2009~~ and Thereafter)

COST ADJUSTMENT FACTOR

		MPS	L&P
Accumulation Period Ending		~~5/31/10~~	~~5/31/10~~
1 Total Energy Cost (TEC)		~~$90,226,379~~	~~$22,334,031~~
2 Base energy cost (B)	-	~~$74,249,464~~	~~$19,644,937~~
3 Crossroads Generating Plant (CGP)	-	$370,035	$0
4~~3~~ First Interim Total		~~$15,976,915~~	~~$2,689,094~~
~~4 Jurisdictional Factor (J)~~	~~*~~	~~99.448%~~	~~100%~~
~~5 Second Interim Total~~		~~$15,888,721~~	~~$2,689,094~~
5~~6~~ Customer Responsibility	*	75~~95~~%	75~~95~~%
6~~7~~ Second~~Third~~ Interim Total		~~$15,094,285~~	~~$2,554,639~~
7~~8~~ Adjustment for Under / Over recovery for prior periods and Modifications due to prudence reviews (C)	+	~~$768,873~~	~~$377,151~~
8~~9~~ Interest (I)	+	~~$421,355~~	~~$41,847~~
9~~10~~ Fuel and Purchased Power Adjustment (FPA)		~~$16,284,513~~	~~$2,973,638~~
10~~1~~ RNSI	÷	~~6,358,211,651~~	~~2,254,414,809~~
11~~2~~ Third~~Fourth~~ Interim Total		~~$0.0026~~	~~$0.0013~~
12~~3~~ Current period CAF_{Prim} (= Line 12 * XF_{Prim})		~~$0.0027~~	~~$0.0014~~
13~~4~~ Previous period CAF_{Prim}	+	~~$0.0038~~	~~$0.0008~~
14~~5~~ Current annual CAF_{Prim}		~~$0.0065~~	~~$0.0022~~
15~~6~~ Current period CAF_{Sec} (= Line 12 * XF_{Sec})		~~$0.0027~~	~~$0.0014~~
16~~7~~ Previous period CAF_{Sec}	+	~~$0.0038~~	~~$0.0008~~
17~~8~~ Current annual CAF_{Sec}		~~$0.0065~~	~~$0.0022~~

Expansion Factors (XF):

Network:	Primary	Secondary
MPS	1.0419~~1.0444~~	1.0712~~1.0679~~
L&P	1.0421~~1.0444~~	1.0701~~1.0700~~

Issued: ~~June 30, 2010~~ Effective: June 4, 2011~~September 1, 2010~~

Issued by: Curtis D. Blanc~~Tim M Rush~~, Sr. Director ~~Regulatory Affairs~~

STATE OF MISSOURI, PUBLIC SERVICE COMMISSION

P.S.C. MO. No. 1 3rd~~2nd~~ Revised Sheet No. 127.5

Canceling P.S.C. MO. No. 1 2nd~~1st~~ Revised Sheet No. 127.5

KCP&L Greater Missouri Operations Company For Territories Served as L&P and MPS

KANSAS CITY, MO ~~64106~~

~~FUEL ADJUSTMENT CLAUSE (CONTINUED)~~

ELECTRIC

~~(Applicable to Service Provided September 1, 2009 and Thereafter)~~

~~COST ADJUSTMENT FACTOR~~

		~~MPS~~	~~L&P~~
~~Accumulation Period Ending~~		~~5/31/10~~	~~5/31/10~~
~~1 Total Energy Cost (TEC)~~		~~$90,226,379~~	~~$22,334,031~~
~~2 Base energy cost (B)~~	~~-~~	~~$74,249,464~~	~~$19,644,937~~
~~3 First Interim Total~~		~~$15,976,915~~	~~$2,689,094~~
~~4 Jurisdictional Factor (J)~~	~~*~~	~~99.448%~~	~~100%~~
~~5 Second Interim Total~~		~~$15,888,721~~	~~$2,689,094~~
~~6 Customer Responsibility~~	~~*~~	~~95%~~	~~95%~~
~~7 Third Interim Total~~		~~$15,094,285~~	~~$2,554,639~~
~~8 Adjustment for Under / Over recovery for prior periods and Modifications due to prudence reviews (C)~~I	~~+~~	~~$768,873~~	~~$377,151~~
~~9 Interest (I)~~	~~+~~	~~$421,355~~	~~$41,847~~
~~10 Fuel and Purchased Power Adjustment (FPA)~~		~~$16,284,513~~	~~$2,973,638~~
~~11 RNSI~~	~~÷~~	~~6,358,211,651~~	~~2,254,414,809~~
~~12 Fourth Interim Total~~		~~$0.0026~~	~~$0.0013~~
~~13 Current period CAF_{Prim} (= Line 12 * XF_{Prim})~~		~~$0.0027~~	~~$0.0014~~
~~14 Previous period CAF_{Prim}~~	~~+~~	~~$0.0038~~	~~$0.0008~~
~~15 Current annual CAF_{Prim}~~		~~$0.0065~~	~~$0.0022~~
~~16 Current period CAF_{Sec} (= Line 12 * XF_{Sec})~~		~~$0.0027~~	~~$0.0014~~
~~17 Previous period CAF_{Sec}~~	~~+~~	~~$0.0038~~	~~$0.0008~~
~~18 Current annual CAF_{Sec}~~		~~$0.0065~~	~~$0.0022~~

~~Expansion Factors (XF):~~

~~Network:~~	~~Primary~~	~~Secondary~~
~~MPS~~	~~1.0444~~	~~1.0679~~
~~L&P~~	~~1.0444~~	~~1.0700~~

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Issued: ~~June 30, 2010~~ Effective: June 4, 2011~~September 1, 2010~~
Issued by: Curtis D. Blanc~~Tim M Rush~~, Sr. Director ~~Regulatory Affairs~~