MISSOURI PUBLIC SERVICE COMMISSION

STAFF'S

RATE DESIGN

AND

CLASS COST-OF-SERVICE

REPORT

UNION ELECTRIC COMPANY d/b/a AMEREN MISSOURI

FILE NO. ER-2011-0028

Jefferson City, Missouri
February 10, 2011

Table of Contents

STAFF'S

RATE DESIGN

AND

CLASS COST-OF-SERVICE

REPORT

I. Executive Summary

Staff's Class Cost-of-Service ("CCOS") and Rate Design recommendations in this case are that the Commission order Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri") to implement the following rate design:

1. The following Ameren Missouri customer classes receive the system average increase, as the revenue responsibilities of the customer classes are close to Ameren Missouri's cost to serve them:

   Small General Service
   Large Transmission Service

2. The Ameren Missouri Residential and Lighting customer classes receive the system average percent increase plus an approximate additional 1% increase, because the current revenue responsibilities of the customer classes are less than Ameren Missouri's cost to serve them.

3. The following Ameren Missouri customer classes receive no increase for the first $30 million, because their current revenue responsibilities exceed Ameren Missouri's cost of serving them. For any Commission ordered increase above $30 million, the additional amount above $30 million should be allocated on an equal percentage basis to the following Ameren Missouri customer classes:

   Large General Service/Small Primary Service
   Large Primary Service

4. Maintain non-residential rate schedules interrelationship uniformity for customer charges, Rider B voltage credits, Reactive charge, and Time-of-Day customer charges.

5. Increase the residential customer charge to $9.00.

6. Combine Ameren Missouri tariffs under one P.S.C. Mo. Schedule number, resolve inconsistencies between the list of communities and counties served by Ameren Missouri in its minimum filing requirements and its tariff, make clarification and typographical corrections in specific tariff sheets, and remove obsolete energy efficiency program tariff sheets.

7. Approve FAC tariff sheets that correspond to the exemplar tariff sheets attached to this report.

8. Ameren Missouri shall complete its evaluation of Light Emitting Diode ("LED"), Street and Area Lighting ("SAL") systems and file a proposed LED lighting rate schedules no later than 12 months following its Report and Order approving tariff sheets in this case or an update to the Commission on when it will file a proposed LED lighting tariff(s).

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

1. To present an overview of Staff's CCOS study and the study results based upon the test year of April 1, 2009, through March 31, 2010, updated and trued-up through February 28, 2011.

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

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

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

5. To provide exemplar Fuel Adjustment Clause ("FAC") tariff sheets that incorporate Staff's recommended changes to Ameren Missouri's FAC and clarify the FAC.

6. To provide the Commission with the reason that Ameren Missouri two tariffs P.S.C. Mo. Schedule No. 1 and P.S.C. Mo Schedule No. 5 need to be combined and other various changes to Ameren Missouri's tariff.

5. To provide the Commission with a recommendation for a high efficiency street and area lighting tariff provision.

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

- Executive Summary
- Class Cost-of-Service and Rate Design Overview
- Staff Class Cost-of-Service Study
- Rate Design
- Ameren Missouri File Its Entire Tariff As A Single Document
- Fuel Adjustment Clause Recommendation
- Street and Area Lighting Recommendation

The results of Staff's CCOS study for Ameren Missouri 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 Staff's determination of Ameren Missouri's cost of serving that class. Staff developed its analysis of the cost of serving each class using inputs taken from the Staff's Revenue Requirement Cost of Service Report ("COS Report") and the Staff Accounting Schedules filed in this case on February 8, 2011. The Staff's revenue requirement as presented in its Accounting Schedules includes expected changes for a true-up ending February 28, 2011, based on current information. For example, the plant and depreciation reserve balances have been adjusted to reflect the anticipated additions through February 28, 2011 true-up period.

Table 1
Summary Results of Staff's CCOS Study - Ameren Missouri

Customer Class	Revenue Deficiency	CCOS % Increase
Residential	$144,594,385	13.21%
Small General Service	($4,965,489)	-1.78%
Large General Service/Small Primary Service	($60,438,738)	-8.52%
Large Primary Service	($11,468,161)	-6.42%
Large Transmission Service	($2,285,337)	-1.64%
Lighting	$6,567,039	21.02%
Total	$72,003,700	2.96%

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 Ameren Missouri 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 customer classes used in its study correspond to Ameren Missouri's current rate schedules, except Staff combined all lighting rate schedules into one customer class for its study. Aside from lighting rate schedules, Ameren Missouri has six rate schedules: Residential ("RES"), Small General Service ("SGS"), Large General Service ("LGS"), Small Primary Service ("SPS"), Large Primary Service ("LPS"), and Large Transmission Service ("LTS"). Staff's customer classes are shown in Table 1 above.

Staff's recommended customer class revenue adjustments would bring the RES, LGS/SPS, LPS, and Lighting classes closer to Ameren Missouri's cost to serve each class. Staff recommends that the SGS and LTS classes receive the system average increase as these classes revenue responsibility are close to Ameren Missouri's cost to serve them. Staff's revenue adjustments bring each class closer to cost of serving them, while still maintaining rate continuity, rate stability, revenue stability; and minimizes rate shock to any customer class.

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

The purpose of a CCOS study is to determine whether each class of customers is providing the utility with a level of revenue reasonably necessary to cover: (1) the utility's investments required to provide service to that class of customers; and (2) the utility's ongoing expenses to provide electric service to that class of customers. A CCOS study provides a basis for allocating and/or assigning to the customer classes the utility's total 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

Ameren Missouri filed a new CCOS study in this case based on the financial data upon which it based its direct filing in this case. The results of Staff's CCOS study appear in Table 1 above and are outlined in Schedule MSS-1. Both show the changes to the current rate revenues of each customer class required to exactly match that customer class's rate revenues with Ameren Missouri's cost to serve that class.

CCOS results can also be presented, on a revenue neutral basis, as the revenue shifts (expressed as negative or positive dollar amounts or percentages) that are required to equalize the utility's rate of return from each class.

Revenue neutral means that the revenue shifts among classes do not change the utility's total system revenues. 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 2.96% from each customer class's required percentage increase to rate revenue to match the revenues Ameren Missouri should receive from that class to match Ameren Missouri's cost to serve that class.

For example, based on Schedule MSS-1, on a revenue neutral basis, the RES customer class is providing 10.25% less revenue (the 13.21% shown in Table 1 minus the average increase of 2.96%) than Ameren Missouri's cost to serve that class. Also, the LGS/SPS customer class is providing 11.48% more revenue to Ameren Missouri than its cost to serve that class. Staff's CCOS study results for all of the customer classes Staff used for Ameren Missouri are presented in Schedule MSS-1.

Because a CCOS study is not precise 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)—for Ameren Missouri customer classes on the LGS/SPS, and LPS rate schedules—all the way to zero is appealing, the bill impact on the customer classes with positive revenue shift percentages must be considered—for Ameren Missouri, customer classes on the RES and Lighting rate schedules. Based on its study results and judgment, Staff recommends revenue adjustments to all Ameren Missouri rate schedules except SGS and LTS, as these customer classes are close to Ameren Missouri's cost to serve them.

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

A. <u>Data Sources</u>

Staff's CCOS study utilized the Staff's revenue requirement position as filed on February 8, 2011, through Staff's direct revenue requirement cost of service recommendation for Ameren Missouri's jurisdictional retail cost of service. This data includes:

- Adjusted Missouri Jurisdictional Investment and cost data by FERC account;
- Annualized, Normalized Rate Revenues;
- Fuel and Purchase Power costs;
- Other operating and maintenance expenses;
- Depreciation and Amortizations;
- Taxes; and
- Off-System Sales.

In addition, data was also obtained from Ameren Missouri witness William Warwick's Direct Testimony and Workpapers from this case, which include:

- 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. These relate to information on services, meters, meter reading, uncollectible accounts, customer premise installations, and customer deposits.

B. Classes and Rate Schedules

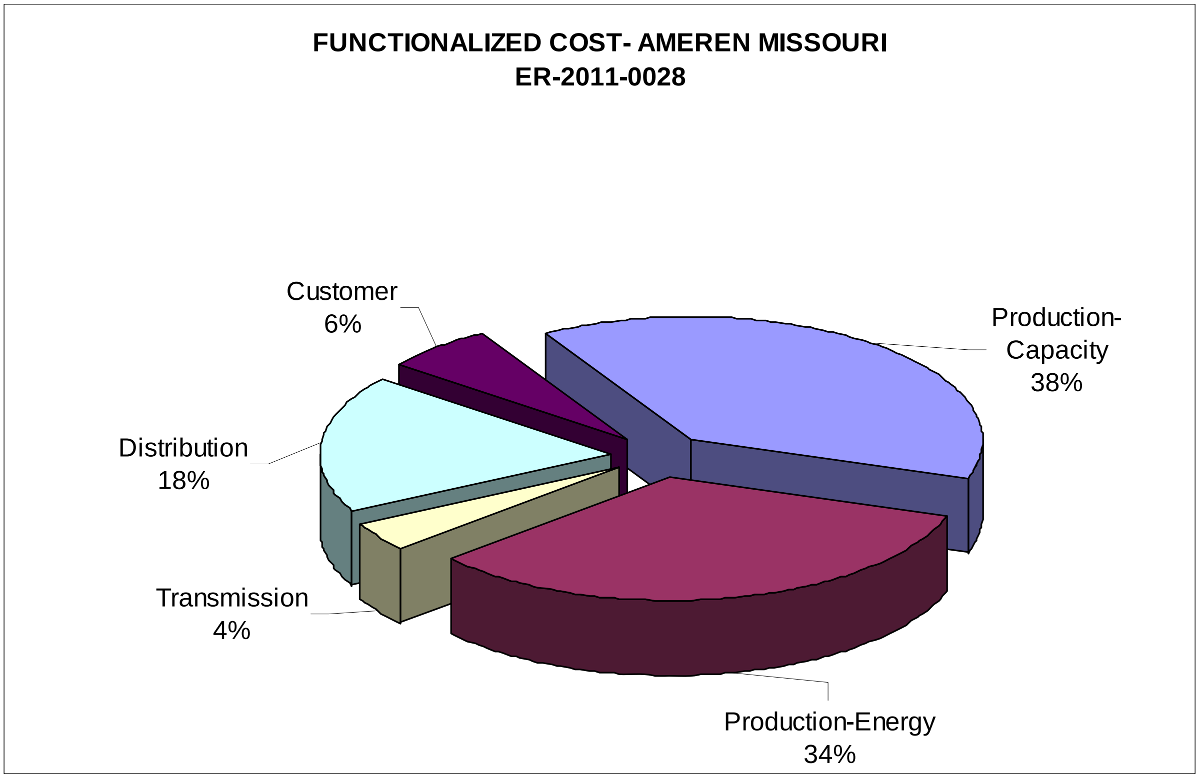
Ameren Missouri currently provides service to its customers in a number of rate classifications that are designated for residential or non-residential service and are listed in Table 1 above. The non-residential customer groups are differentiated by voltage level and/or by kW demands.

C. Functions

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

Energy-related costs are those costs related directly to the customer's consumption of electrical energy (kilowatt-hours) and consist primarily of fuel, fuel handling, and the energy portion of net interchange power costs. The chart below shows the percentage of total costs associated within each major function for all of Ameren Missouri's classes, as consolidated.

TABLE 2



The Production Function (combination of Production-Capacity and Production-Energy) is the single largest cost component, and represents 72% of the total cost. The Distribution Function, at 18% of the total cost, is the second largest contributor to total cost, and includes substations, overhead and underground lines, and line transformers, as well as the costs to operate and maintain this equipment. Customer Services at 6% and Transmission at 4% round out the total cost. Schedule MSS-2 provides a detailed description of each external allocation factor Staff used in its CCOS study.

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

Allocators are used to distribute the functionalized costs to the classes. The Production investment and costs comprise approximately 72% of the functionalized investment and cost. Both the demand and energy characteristics of Ameren Missouri'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 based on a Base-Intermediate-Peak ("BIP") method. Staff allocated Production-Energy fuel costs on annualized kWh usage at generation. The BIP method is based on recognition that capacity 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[1] of demand for electricity for a given class minus the base component previously allocated; and
3. A peaking component consisting of the average 3 NCP[2] component of demand for electricity less the base and intermediate components previously allocated.

The BIP method is described in the National Association of Regulatory Utility Commissioners (NARUC) ELECTRIC UTILITY COST ALLOCATION MANUAL, January 1992 ("NARUC Manual"). 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, or intermediate hours; and (3) base loading hours. Generally, base load units have high capital costs, generally take five to ten years to build and have low, constant running costs. Because of this, these units run almost continuously, except during periods of maintenance. Because base load units operate regardless of peak requirements,

[1] 12 NCP is each month's maximum peak demand of each customer class at any time during the months of January through December.
[2] 3 NCP is each month's maximum peak demand of each customer class during June, July, and August.

they are appropriately classified as energy-related.[3] 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.[4] Peaking units have low capital costs, are relatively quick to build—typically twelve to eighteen months—but are costly to run. It is typically most cost effective to only run these units for the few hours of the year when the system load is the highest. The output of peaking units is most effectively used when it is changed to follow the energy requirements of the system on a real-time basis.

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

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. 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;

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

---

[3] **Energy-related**: Energy-related costs are those costs related directly to the customer's consumption of electrical energy (kilowatt-hours) and consist primarily of fuel, fuel handling, and the energy portion of net interchange power costs.

[4] **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.

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

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 3 below, helps to define the twelve months in terms of a peak season and a non-peak season. Ameren Missouri is a summer peaking utility (see Table 3) with the system's two highest monthly coincident peaks occurring in the summer season (June through July).

Table 3

Coincident System Peak @ Generation (kW)		
Month	kW Peak	% of Annual Peak
Apr-09	5,163,534	65.0%
May-09	5,883,381	74.0%
Jun-09	7,201,949	90.6%
Jul-09	7,947,980	100.0%
Aug-09	7,065,101	88.9%
Sep-09	6,655,380	83.7%
Oct-09	5,050,963	63.6%
Nov-09	5,549,457	69.8%
Dec-09	6,908,643	86.9%
Jan-10	7,076,614	89.0%
Feb-10	6,808,345	85.7%
Mar-10	5,696,574	71.7%

In the BIP method, the base allocator (the "B" portion in BIP) is calculated on each class's annual kWh 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. The intermediate piece (the "I" in BIP) involves using the average of the 12 Non-Coincident Peaks ("NCP") for the intermediate piece. The NCP demand is defined as the maximum monthly peak demand of each customer class at any time during the study period, and it may or may not fall on the same hour as the system peak for that month. The intermediate portion is determined by the intermediate peak less the base portion already allocated to the various classes. The final step is to determine the peak portion (the "P" in BIP) for allocation to the various classes. The peak portion is allocated to the various classes based on each class's share of the summer peak (June, July, August) less the base and intermediate portions already allocated to the various classes. Staff used the three summer months during the test year for calculating the production–capacity cost allocator, since the three highest peaks are within approximately 90% of the system peak.

The BIP method takes into consideration the differences in the capacity/energy cost trade-off that exists across a company's generation mix. The BIP methodology gives weight to both considerations. It does so by considering energy in the base component through the allocation of base usage to all classes and by considering capacity in the allocation of intermediate and peak components. For these reasons, Staff recommends using the BIP method for production investment and for production costs for Ameren Missouri. Staff explains the BIP method further, and addresses other production methods from the NARUC Manual, in attached Appendix A (Appendix A – p. 12). The BIP method is outlined in the NARUC Manual in Part IV C Section 2. Schedule MSS-4 details the BIP method as described in the NARUC Manual.

E. <u>Allocation of Transmission Costs</u>

Ameren Missouri's transmission investment and transmission costs comprise approximately 4% of the functionalized investment and costs Staff allocated to the customer classes. Ameren Missouri'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 voltages. Staff allocated Transmission investment and costs to the customer classes on a 12 coincident peak ("12 CP") basis. Staff recommends the 12 CP allocation method for this purpose because by including periods of normal use and intermittent peak use throughout all twelve months of the year it takes into account the needs for a transmission system that is designed to transmit electricity during both peak loads and also to transmit electricity throughout the year.

F. Allocation of Distribution Costs

Voltage level is a factor that Staff considered when allocating distribution costs to customer classes. A customer's use or non-use of specific utility-owned equipment is directly related to the voltage level needs of the customer. All residential customers are served at secondary voltage; non-residential customers are served at secondary, primary, substation, or transmission level voltages. Only those customers in customer classes served at substation voltage or below (i.e., all substation, primary and secondary customers) were included in the calculation of the allocation factor for distribution substations. Staff used the annual class peak of these customer classes to allocate substation costs, because it includes the appropriate level of diversity at the distribution substation.

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

Table 4
Allocation of Demand Related Distribution Facilities

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

Coincident peak demand is defined as the demand of each customer class and each customer at the hour when the overall system peak occurs. Coincident peak demand reflects the maximum amount of diversity, because most customer classes are not at their individual class peaks at the time of the coincident peak. Class peak demand, 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 (system peak). Although, not all customers peak at the same time (due to intra-class 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.

Staff recommends allocating 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 served at the secondary voltage level were included in the calculation of the allocation factor, so that distribution secondary costs were allocated only to those customers that use these facilities.

Ameren Missouri conducted special studies to split the cost of poles, towers, fixtures; and overhead ("OH") and underground ("UG") distribution lines between the portions that are primary and secondary related.

Staff recommends allocating meter costs using Ameren Missouri's allocator. This allocator is based on an Ameren Missouri study that weights the meter investment by class, and by the cost of the meter used to serve that class.

G. <u>Allocation of Customer Service Costs</u>

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 recommends using Ameren Missouri's allocators for allocating meter reading costs, uncollectible accounts, and for allocating customer deposits. These three allocators are derived in Ameren Missouri's studies that directly assign the costs of meter reading, uncollectible accounts, and customer deposits to the customer classes. The allocators are the fraction of total costs of meter reading, uncollectible accounts and customer deposits assigned to each class, respectively. Staff allocated other customer service accounts on unweighted customer counts or according to Ameren Missouri's CCOS study.

H. <u>Revenues</u>

Operating revenues consist of (1) the revenue that the utility collects from the sales of electricity to Missouri retail customers (rate revenue); and (2) the revenue the utility receives for providing other services (other revenue). Rate Revenues are also used in developing Staff's rate design proposal and will be used to develop the rate schedules required to implement the Commission's ordered revenue requirement and rate design for Ameren Missouri in this case. Rate Revenues in Staff's COS Report filed February 8, 2011, were used to obtain Ameren Missouri's normalized and annualized rate revenues. The Total Rate Revenues as shown in the Rate Revenue Summary in Staff's Accounting Schedules filed on February 8, 2011 is $2,433.1 million.

Other Electric Revenues of $469.7 million were also allocated to the rate classes using Staff's production-energy and other cost allocators. The majority of other electric revenues pertains to off-system sales ("OSS"). OSS are those sales of electricity made after Ameren Missouri has met all obligations to serve its native load customers (retail and full requirements wholesale customers). This excess energy is then available to sell to other utilities. By engaging in OSS, Ameren Missouri generates profits or net margin, which represents sales less associated generation or purchased power cost. OSS represents an efficient utilization of the electric facilities/system that has been put in place to meet the electricity needs of Ameren Missouri's customers. Staff allocates off-system sales to customer classes on the basis of energy usage by the customer class at the generation level.

Staff Expert/Witness: 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 change in customer revenue responsibility.
- Retain, to the extent possible, existing rate schedules, rate structures, and important features of the current rate design that reduce the number of customers that switch rates looking for the lowest bill, and mitigate the potential for rate shock.
- Provide exemplar Fuel Adjustment Clause ("FAC") tariffs that incorporate Staff's recommended changes to Ameren Missouri's FAC and clarify the FAC.
- Provide the Commission with the reason that Ameren Missouri's two tariffs P.S.C Mo. Schedule No. 1 and P.S.C. Mo. Schedule No. 5 need to be combined and other various changes to Ameren Missouri tariff.
- Provide the Commission with a recommendation for a high efficiency street and area lighting tariff provision.

Staff's rate design recommendations in this case are:

1. That Ameren Missouri's rate schedules should be uniform for certain interrelationships among the non-residential rate schedules that are integral to Ameren Missouri's rate design. The following features are uniform and should remain uniform:
    - The value of the customer charge be uniform across rate schedules, with the customer charge on the SPS, LPS, and LTS rate schedules being the same.
    - The rates for Rider B voltage credits be the same under all applicable rate schedules.
    - The rate for the Reactive Charge be the same for all applicable rate schedules.

- The rate associated with Time-of-Day meter charge be the same for all applicable non-residential rate schedules (LGS, SPS, LPS, and LTS).

2. The following Ameren Missouri customer classes receive the system average increase, as the revenue responsibilities of these customer classes are close to Ameren Missouri's cost to serve them:

   - Small General Service
   - Large Transmission Service

3. The Ameren Missouri Residential and Lighting customer class receive the system average percent increase plus an approximate additional 1% increase, because the current revenue responsibilities of the customer classes are less than Ameren Missouri's cost to serve them.

4. The following Ameren Missouri customer classes receive no increase for the first $30 million, because their current revenue responsibilities exceed Ameren Missouri's cost of serving them. For any Commission ordered increase above $30 million, that the additional amount above $30 million be allocated on an equal percentage basis to the following Ameren Missouri customer classes.

   - Large General Service/Small Primary Service
   - Large Primary Service

5. The Residential customer charge be increased from $8.00 to $9.00 per month excluding low-income assistance charge.

6. That the energy charges for the residential class be increased uniformly, after making the adjustments described in 3. and 5. above.

7. That the energy charges for the SGS class be increased uniformly, after making the adjustments described in 2. above.

8. That the demand and energy charges for the LGS/SPS class be increased uniformly after making the adjustments described in 1. and 4. above.

9. That the demand and energy charges for the LPS class be increased uniformly after making the adjustments described in 1. and 4. above.

10. That the demand and energy charges for the LTS class be increased uniformly after making the adjustments described in 1. and 2. above.

11. That the lighting charges be increased uniformly after making the adjustments described in 3. above.

Schedule MSS-3 shows that Ameren Missouri's residential customer charge is the second lowest of the five electric utility tariffs in the state. The results of Staff's CCOS study show that customer costs of 1.21 times the $8.00 existing customer charge or $9.67. Staff recommends increasing Ameren Missouri's residential customer charge by $1.00, from $8.00

to $9.00 after considering and taking into account the: (1) potential for rate shock of going to the $9.67 that it costs Ameren Missouri to provide the customer-related functions; and (2) Staff's revenue neutral rate increase recommendation for the residential class.

A. <u>Current Rate Schedules</u>

The residential rate schedules consist of the following elements:

- Regular Service Rate Schedule
- Optional Time of Day rate schedule
- Customer Charge – per month per season
- Low-Income Pilot Program Charge – per month per season
- Energy Charge – per kWh per season
- Fuel and Purchased Power Adjustment – per kWh

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

Small General Service Rate schedules consist of the following elements:

- Small General Service Rate Schedule
- Optional Time of Day Rate Schedule
- Customer Charge (Single or Three-Phase Service) – per month per season
- Low-Income Pilot Program Charge – per month per season
- Summer Energy Charge – per kWh per season – base use and seasonal use
- Winter Energy Charge – Base Energy Charge – Hours of Use per kW of base demand and seasonal energy charge per kWh
- Fuel and Purchased Power Adjustment – per kWh

Large General Service Rate schedules consist of the following elements:

- Large General Service Rate Schedule
- Optional Time of Day Rate Schedule
- Customer Charge – per month per season
- Low-Income Pilot Program Charge – per month per season

- Summer Energy Charge – Hours of use per kW of billing demand - per kWh per season
- Winter Energy Charge – Base Energy Charge – Hours of Use per kW of base demand and seasonal energy charge per kWh
- Demand Charge – per kW of total billing demand per season
- Fuel and Purchased Power Adjustment – per kWh

Small Primary Service Rate schedules consist of the following elements:

- Small Primary Service Rate Schedule
- Optional Time of Day Rate Schedule
- Customer Charge – per month per season
- Low-Income Pilot Program Charge – per month per season
- Energy Charge – Hours of use per kW of billing demand - per kWh per season
- Demand Charge – per kW of total billing demand per season
- Reactive Charge – per kVar per season
- Fuel and Purchased Power Adjustment – per kWh

Large Primary Service Rate schedules consist of the following elements:

- Large Primary Service Rate Schedule
- Optional Time of Day Rate Schedule
- Customer Charge – per month per season
- Low-Income Pilot Program Charge – per month per season
- Energy Charge – per kWh per season
- Demand Charge – per kW of billing demand per season
- Reactive Charge – per kVar per season
- Fuel and Purchased Power Adjustment – per kWh

Large Transmission Service Rate schedules consist of the following elements:

- Large Transmission Service Rate Schedule
- Optional Time of Day Rate Schedule
- Customer Charge – per month per season
- Low-Income Pilot Program Charge – per month per season

- Energy Charge – per kWh per season
- Demand Charge – per kW of billing demand per season
- Reactive Charge – per kVar per season
- Energy Line Loss Rate – per kWh
- Fuel and Purchased Power Adjustment – per kWh

B. Lighting

- Street and Outdoor Area Lighting 5(M) – Company owned
- Street and Outdoor Area Lighting 6(M) – Customer owned
- Municipal Street Lighting 7(M)
- Private Ornamental Street Lighting 8(M)
- Unmetered service
- Metered service
- Discounted rates for municipalities with franchise agreements
- Existing revenue - $31.2 million

C. Important Rate Design Features

Ameren Missouri's charges are determined by each customer's usage and the (per unit) rates that are applied to that usage. Within each rate schedule, demand and energy rates should continue to be seasonally differentiated (i.e., summer rates are higher than winter rates). The remaining rates (customer, facilities, reactive) should be constant year-round. Ameren's rate schedules should be uniform for certain interrelationships among the non-residential rate schedules that are integral to Ameren Missouri's rate design. Staff recommends that the following features maintain their uniformity:

- The value of the customer charge be uniform across rate schedules, with the customer charges on the SPS, LPS, and LTS rate schedules being the same.
- The rates for Rider B voltage credits be the same under all applicable rate schedules.
- The rate for the Reactive Charge be the same for all applicable rate schedules.

- The value of the customer charge for Time-of-Day be uniform across rate schedules, with the customer charges on the LGS, SPS, LPS, and LTS rate schedules being the same.

The rate schedules should continue to reflect any cost difference associated with service at different voltage levels (i.e., losses and facilities ownership by customers).

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

- Small General Service: Applicable to secondary service. Summer demand does not exceed 100 kW.
- Large General Service: Applicable to secondary service. Summer demand exceeds 100 kW.
- Small Primary Service: Applicable to primary service. Summer demand exceeds 100 kW.
- Large Primary Service: Applicable to primary service. Billing demand no less than 5000 kW.
- Large Transmission Service: Applicable to transmission service. Billing demand no less than 5000 kW.

For its CCOS study, Staff broke the above rate groups into the four separate rate classes with the LGS and SPS combined into one rate class for purposes of the study. Staff combined the LGS and SPS rate classes for purposes of its CCOS study for the following reasons. First, both rate schedules serve non-residential customers with billing demands of at least 100 kW. Within this group, a customer may choose to take service at secondary voltage level under the LGS 3(M) rate schedule or at a primary voltage level under the SPS 4(M) rate schedule. The rate structures are identical, except that the rate levels on the SPS rate schedule have been adjusted for the loss differential between primary and secondary voltages and to account for customer provision of voltage transformation equipment. The Staff's CCOS study provided the investment and costs associated for Ameren Missouri to provide service to the Lighting class.

Staff Expert/Witness: Michael S. Scheperle

V. Other Tariff Issues

A. <u>Multiple Numbers in Current Tariff</u>

Staff recommends the Commission order Ameren Missouri to file tariff sheets that incorporate several format modifications to improve the clarity of its tariff as a whole. Staff recommends the Commission order Ameren Missouri to file its entire tariff as a single document, bearing the designation "P.S.C. Mo. No. 6" to replace the several documents currently on file with the Commission with various designations when it files its compliance tariff sheets in this case. The compliance filing shall include all schedules of rates, riders, rules, and regulations, plus incorporate the cogeneration and net metering tariff sheets presently under P.S.C. Mo. Schedule No. 1. The Staff recommends these changes for the following reasons:

1. The changes will make it easier for Ameren Missouri customers to know which tariff applies to them. The Company name on the tariff (Union Electric Company d/b/a Ameren Missouri) will contain the same name that customers receive bills from – Ameren Missouri.
2. Ameren Missouri's Cogeneration and Net Metering tariff sheets will be in the same P.S.C. Mo. No. as all other Ameren Missouri tariff sheets. Currently these tariff sheets are under an incorrect P.S.C. Mo. No. that was used in the far past for all tariff sheets.
3. The tariff will be cleaned up, reorganized and blank sheets will be removed.
4. A new section can be created for all the energy efficiency and demand response programs.

If the Commission adopts Staff's recommendation to require Ameren Missouri to file its tariff under a new number, every tariff sheet will be modified. Therefore, Staff requests that the Commission decision leave Staff sufficient time to review the approximately 200 tariff sheets that will be filed.

B. Listing of Communities and Counties Served in Ameren Missouri's Tariff

Staff compared the listing of communities and counties that Ameren Missouri serves provided by the Company in its minimum filing requirements with the communities and counties listed in its tariff and found some discrepancies. There were two counties (Bollinger and Butler) and four communities (Castor, Mine LaMotte, Polk, and Union) that are listed in Ameren Missouri's tariffs that are not included in the minimum filing requirements of this case. Staff will work with Ameren Missouri to determine if the Company still serves customers in these counties and communities. If it does not and Ameren Missouri does not have a Certificate of Convenience and Necessity to serve these counties and communities, Staff recommends that these counties and communities be removed from Ameren Missouri's tariff.

C. Changes to Specific Tariff Sheets

To initiate this case, File No. ER-2011-0028, Ameren Missouri filed certain tariff sheets which were docketed as File No. YE-2011-0116. Specific to those sheets, Staff recommends the Commission order Ameren Missouri to file tariff sheets incorporating the following typographical corrections:

1. Sheet No. 32, In the "Charges" column (on right side) – word wrap "June" and "October" out of the columns (top to bottom) alignment.
2. Sheet No. 45, add "(4)" to "N/A – Not Available." just above "Term of Contract".

In addition to the issues identified for tariff sheets filed by Ameren Missouri in File No. YE-2011-0116, Staff has also identified concerns with other Ameren Missouri tariff sheets. The items of concern, Staff's recommendation to alleviate each concern, and the reason for Staff's concern are as follows:

1. **Staff recommends Ameren Missouri include sample contracts in the tariff for the services described on Tariff Sheet No. 41, Street And Outdoor Area Lighting – Company-Owned, and on Tariff Sheet No. 45, Street And Outdoor Area Lighting – Customer-Owned.** Ameren Missouri's current tariff does not include sample contracts or agreements related to Street and Outdoor Lighting. Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company currently include sample lighting contracts in their tariffs. If the Commission does not require Ameren Missouri's Tariff to be renumbered, Tariff Sheet Nos. 48 and 49 each bear only "Blank Sheet," and are reasonable locations to place the draft contracts.

2. **Update Ameren Missouri's Tariff Sheet No. 98, Table of Contents for Riders.** On Tariff Sheet No. 98, the reference to "Voluntary Curtailment Rider, Sheet No. 116" should be changed to "Peak Power Rebate, Sheet No. 115.1." "SR, Solar Rebate, Sheet No. 122.14" and SP, SREC Purchase, Sheet No. 122.16 do not currently appear on the Tariff Sheet No. 98, Table of Contents for Riders, and should be added.

3. **Update Ameren Missouri's Tariff Sheet No. 125, Table of Contents for Rules & Regulations**. The reference to IX. Pilots, Variances and Promotional Practices A. "Residential Time-Of-Use Pilot" should be changed to "Personal Energy Manager Rebate Pilot", Sheet No. 192.

4. **A definition for "Permanent Service" should be added to Tariff Sheet No. 130, Definitions.** The definition that has been adopted by Empire District Electric is satisfactory, and is as follows: "Permanent Structure" means any structure used for residential or commercial purposes that has a permanent foundation, water service, and sanitary sewer or septic service. Structures otherwise referred to as mobile homes shall also be classified as permanent structures when they meet these requirements.

5. **Ameren Missouri's Tariff Sheet No. 147, Distribution Extension Cost should specify that Ameren Missouri will furnish a customer copy of charges prior to construction.** The language, "Ameren Missouri will furnish customer copy of charges prior to construction," should be added to the end of the paragraph.

6. **Ameren Missouri's Tariff Sheet Nos. 192, 193, 193.1, 194, 196, 198, 199, 200, 201, 202, 203, 204, 205, 205.1, 207, 208, 210, 211, 212, 213, 214, 215, 216, 217, 218 should each specify that they are applicable to Pilots, Variances, and Promotional Practices.** On each of these sheets, Ameren Missouri should add to header of each sheet the following to be centered:

   GENERAL RULES AND REGULATIONS
   PILOTS, VARIANCES AND PROMOTIONAL PRACTICES

   The header described above should also be added to Tariff Sheet Nos. 195 and 197. For consistency with other tariff sheets, the program title for the applicable program should be added to Tariff Sheet Nos. 195 and 197.

7. **Correct a typographical error on Tariff Sheet No. 202, Unregulated Competition Waivers.** The extraneous"*R." on first line next to "Unregulated Competition" should be deleted.

D. <u>Expired Energy-Efficiency Program Tariff Sheets</u>

Several tariff sheets applicable to expired energy-efficiency programs remain in Ameren Missouri's tariff. Ameren Missouri should remove these obsolete sheets from its tariff. The effected tariff sheets are:

1. Sheet Nos. 204, 205, 205.1 – Missouri Commercial Facility Energy Audit Program, expired on 7/31/07
2. Sheet Nos. 207, 208 – Missouri Change A Light Program, expired on 12/31/07
3. Sheet Nos. 211, 212 – Voluntary Missouri Energy Efficiency Refrigerator Bounty and Recycling Program, expired on 12/31/05
4. Sheet Nos. 213, 214, 215 – Missouri LEED™ Incentive Grant Program, expired on 9/30/09

E. Cogeneration and Net Metering Tariff Sheets

If the Commission does not adopt Staff's recommendation to require Ameren Missouri to file its tariff under a new number, several revisions are necessary regarding P.S.C. Mo. Schedule No. 1, Electric Power Purchases. P.S.C. MO. Schedule No. 5 was Ameren Missouri's schedules of rates in 1982 when the original (initial) filing of the cogeneration tariff was filed with the Commission. Ameren Missouri was allowed to use P.S.C. Mo. Schedule No. 1 for its cogeneration tariff sheets. Ameren Missouri's net metering tariff sheets were also filed in P.S.C. Mo. Schedule No. 1. The designation "P.S.C. Mo. Schedule No. 1" was used in 1924, and should not be used twice under the Missouri PSC per 4 CSR 240-3.145(7) Filing Requirements for Electric Utility Rate Schedules:

> (7) All schedules of rates filed with the commission shall bear a number with the following prefix: PSC Mo. Rate schedules shall be numbered in consecutive serial order commencing with a No. 1 for each electrical corporation (for example, the first schedule PSC Mo., No. 1). The prefixes and numbers shall be printed on schedules as required by section (9) of this rule. For convenience the prefix is referred to as PSC.

Therefore Staff recommends that if the Commission does not adopt Staff's recommendation to require Ameren Missouri to file its tariff under a new number, the Commission require Ameren Missouri to

1. Move its "Electric Power Purchases" tariff sheets from P.S.C. MO. Schedule No. 1 to P.S.C. MO. Schedule No. 5. The tariff sheets can be moved to Sheets No. 69 through 97.8 which are currently tariff sheets that are "reserved for future use."

2. Add to the Table of Contents on Sheet No. 27 “Electric Power Purchases from Qualifying Facilities, Sheet No. 69” and “Electric Power Purchases from Qualified Net Metering Units, Sheet No. 76”

Staff Expert/Witness: William (Mack) L. McDuffey

VI. Fuel and Purchased Power Adjustment Clause

In its COS Report in this case, Staff provided its analysis of Ameren Missouri’s Fuel Adjustment Clause (“FAC”) and provided its recommendations relevant to calculating the impact of Ameren Missouri’s FAC on Ameren Missouri’s revenue requirement.

Implementation of certain of those recommendations requires modification or clarification of Ameren Missouri’s FAC tariff sheets. In addition to those tariff changes directly relating to Ameren Missouri’s revenue requirement, Staff is recommending changes to Ameren Missouri’s FAC tariff sheets to reduce customer confusion, simplify administration, and improve the performance of Ameren Missouri’s FAC. Specifically, Staff recommends the Commission order Ameren Missouri to file tariff sheets addressing the following issues not identified in the COS Report:

1. Provide expansion factors to account for distribution losses to the loss level of Ameren Missouri’s Midwest Independent Transmission System Operator (“MISO”) load node;
2. Require the true-up filing to occur on the same day as the filing to change the Fuel and Purchased Power Adjustment (“FPA”);
3. Reflect the changes to the FAC proposed by Ameren Missouri witness Lynn Barnes that Staff agrees with; and
4. Coordinate the timing of the tariff effective date.

Staff recommends the Commission order Ameren Missouri to file tariff sheets addressing the following issues that were identified in the COS Report:

1. Rebase the summer and winter Net Base Fuel Cost (“NBFC”) in this case;
2. Use the Ameren Missouri’s load at its MISO load node to calculate the NBFC rate, determine the accumulation period kWh sales and forecast the recovery period kWh sales;

3. Reduce the length of the recovery periods from 12 months to 8 months; and
4. Change the sharing mechanism from 95%/5% to 85%/15%.

A. <u>FAC Tariff Items Not Identified in the Cost of Service Report</u>

<u>Expansion Factors Compatible with Distribution Losses to the MISO load node</u>

Ameren Missouri's current FAC tariff sheets kWh sales used in the calculation of the NBFC rate are inconsistent with the accumulation kWh sales used by Ameren Missouri. This results in either an over- or an under-estimation of funds to be billed during a recovery period. For consistency, the expansion factors used to adjust the FPA for losses must be consistent with the loss factor that is used to calculate the NBFC from the test year data. Staff has estimated the expansion factors to be 1.0657, 1.0331, and 1.0000 for secondary, primary and transmission level voltages respectively. These expansion factors have been estimated from Ameren Missouri's most recent loss study and adjusted to be consistent with test year data. These estimates will be revised and finalized during the true-up portion of this case.

<u>True-Up Filing to Coincide with FPA Filing</u>

Ameren Missouri's current FAC tariff sheets do not require that it file its FAC true-up concurrently with its filing of adjustments to its FAC. Ameren Missouri filed its first true-up on December 1, 2010, seven days on after it filed to change its FPA on November 25, 2010. In order for the true-up to go into effect at the beginning of the next recovery period, either Staff or the Commission would have to complete its review in less than the 30 days allowed it or the true-up amount will not be part of the FPA until six months later. Staff recommends the Commission require the true-up filing to occur on the same day as the filing made to adjust Ameren Missouri's FPA. Page 98.6 of Schedule DCR-1 shows this change.

Changes to the FAC proposed by Ameren

Staff agrees with Ameren Missouri witness Lynn Barnes about removing the Taum Sauk ("TS") factor and the Black Box Settlement ("S") factor from the tariff. These changes are reflected in the exemplar tariffs in Schedule DCR-1. Staff does not agree with Ameren Missouri on the definition of Off-System Sales Revenue ("OSSR") and Staff's position is that the language "…excluding Missouri retail sales and long-term full and partial requirements sales to Missouri municipalities…" on page 98.3 of Schedule DCR-1 should remain as written in the current tariff.

Timing of the FAC Tariff Effective Date

In its tariff filing that started this case, Ameren Missouri filed revisions to its revised FAC tariff sheets numbered 98.1 through 98.14 that the Commission approved in Case No. ER-2010-0036 and made effective June 21, 2010. The FAC includes three 4-month accumulation periods which end May 31, September 30, and January 31. It is likely that the effective date of the FAC tariff sheets approved in this case will not be May 31, September 30 or January 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 the exemplar tariff sheets in Schedule DCR-1 be approved in this case. Schedule DCR-1 specifies that the provisions of the current FAC tariff sheets be applicable for determining the difference between Actual Fuel Costs and NBFC 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 effective date of the new FAC tariff sheets.

B. **Items identified in the Cost of Service Report**

Rebasing NBFC Summer and Winter Rates

Staff recommends the Commission change the amount of the summer and winter NBFC rate used in the FAC to match what it orders included in Ameren Missouri's cost of service for generally increasing Ameren Missouri's rates in this case. Based on the fuel, purchased power and other costs and offsets included in Ameren Missouri's FAC for Ameren Missouri in Staff's direct case, Staff has estimated a summer NBFC of $186,410,289 and a winter NBFC of $309,303,537. The rebased Summer NBFC rate is estimated at 1.330 cents per kWh and the rebased Winter NBFC Rate is estimated at 1.203 cents per kWh as provided on Sheet No. 98.5 of Schedule DCR-1. These rates represent a 7.6% increase in the summer rate and a 15.23% increase in the winter rate from the current summer and winter rates. These estimates will be revised and finalized during the true-up period for this case.

Use the MISO load node for calculating the NBFC rate, the recovery period sales, and for forecasting the recovery period kWh sales.

Ameren Missouri's current FAC tariff sheets use kWh at generation for calculating the NBFC rate, recovery period sales and forecasting recovery period kWh sales. Staff recommends changing the NBFC rates found: (1) on tariff sheet 98.5; (2) in the definition of the accumulation period sales; and (3) in the definition of the recovery period sales estimates to be kWh at the MISO load node voltage. These changes are designed to make the methods used to calculate the base fuel cost and actual fuel cost in each accumulation period more consistent.

Reduce the Length of the Recovery Periods

The current tariff establishes the following 12-month recovery periods:

- October through September

- February through January
- June through May

Staff recommends that the recovery periods be shortened to eight months in length in order to reduce the "regulatory lag" of the FAC Cycle Period (the period of time from the start of an accumulation period to the end of the recovery period that collects the last dollar cost from the accumulation period). Tariff sheet 98.1 in Schedule DCR-1 provides the following recovery periods and the corresponding accumulation periods:

Accumulation Period (Calendar Months)	Recovery Period (Billing Months)
February through May	October through May
June through September	February through September
October through January	June through January

<u>Change of the Sharing Mechanism to 85%/15%</u>

Ameren Missouri's current FAC tariff sheets authorize a 95%/5% sharing mechanism. Staff recommends changing the sharing mechanism from 95%/5% to 85%/15%. In addition to the contested cases currently open before the Commission regarding the results of Staff's first prudence review and Ameren Missouri's first true-up request, Staff is concerned about the increase in fuel costs between 2009 and 2010 and a drop in off-system sales megawatt-hours despite an increase in the actual price (dollars per megawatt) received. Changing the sharing mechanism to 85%/15% is designed to provide incentive for more off-system sales. Exemplar tariff sheets 98.1, 98.2 and 98.7 of Schedule DCR-1 reflect this recommendation.

Staff Expert/Witness: David C. Roos

VII. Street and Area Lighting Recommendation

Staff recommends that the Commission order Ameren Missouri to complete its evaluation of Light Emitting Diode ("LED"), Street and Area Lighting ("SAL") systems, and no later than 12 months following the Commission's Report and Order in this case, file either a proposed LED lighting tariff(s) or an update to the Commission on when it will file a proposed LED lighting tariff(s).

A. Current Street Lighting for Ameren Missouri

Currently, Ameren Missouri has approximately 212,800 SAL systems for the 1,568 public street and municipal lighting customers in its service territory, using a total of about 137,000 MWh according to its 2009 Annual Report. Ameren Missouri's currently approved lighting tariffs consist of the following Service Classifications ("SC"): 1) street and outdoor area lighting – company-owned (SC NO. 5 (M)); 2) street and outdoor area lighting – customer-owned (SC NO. 6 (M)); 3) municipal street lighting – incandescent (SC NO. 7 (M)); and 4) private ornamental street lighting (SC NO. 8 (M)). The rate in SC NO. 5(M) for Company-owned street and outdoor area lighting includes the installation and maintenance costs of the lighting, in addition to the energy costs. The other rates in SC NOs. 6 (M), 7 (M), and 8 (M) (customer-owned, municipal, and private ornamental, respectively) include energy and maintenance costs or energy costs only because SALs in these classifications are customer owned[5]. Virtually, most of the existing lighting in the Company's service area is high pressure sodium ("HPS") lamps or mercury vapor ("MV") lamps[6], which were determined the most efficient available technology for the SAL at the time the Company installed most of these SALs.

[5] Currently, there is no SAL under SC NO. 8 (M).
[6] HPS and MV lamps are about 65% and 32% of the total lamps, respectively.

B. An Alternative for the SAL System: Light Emitting Diode (LED) Lighting

The LED lighting system is the most energy efficient SAL fixture available today. Some advantages of LED lighting over traditional high-intensity discharge ("HID") lamps and HPS lamps include:

- Improved efficiency;
- Longer lamp life;
- 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)7

D. 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.[8] 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 such replacements will be eligible for a rebate for every qualified LED fixture purchased and installed.[9]

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[10], but also a 'Midnight'

[7] http://www.pge.com/mybusiness/energysavingsrebates/rebatesincentives/ref/lighting/lightemittingdiodes/streetlightprogram.shtml

[8] See PG&E's LS-2 rate schedule at http://www.pge.com/tariffs/tm2/pdf/ELEC_SCHEDS_LS-2.pdf

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

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

service 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. The Staff understands 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[11] have launched pilot LED SAL programs, including the Missouri cities of Columbia, Ballwin, Independence, Kansas City, and Springfield.

E. <u>Ameren Missouri's LED SAL Research12</u>

Ameren Missouri is collaborating with the Electric Power Research Institute ("EPRI") and other utilities to test and evaluate the potential of currently available LED lighting through EPRI's National Demonstration Project, which includes nine national sites with 12 LED lights normally installed per site. However, Ameren Missouri installed 11 LED lights in Ballwin, Missouri. This project started in summer of 2009 and will end sometime in fourth quarter of 2011. As a project participant, Ameren Missouri is interfacing with EPRI for data collection in metering and photometric measurement of the LED lighting. EPRI will provide a final report at the end of project.

F. <u>Staff Recommendation</u>

Staff recommends that the Commission order Ameren Missouri to complete its evaluation of LED SAL systems, and no later than 12 months following the Commission's Report and Order in this case file either a proposed LED lighting tariff(s) or an update to the Commission on when it will file a proposed LED lighting tariff(s). Staff is not recommending

[11] http://newstreetlights.com/index_files/New_Streetlights_News_100.htm
[12] Based on the Data Request No. 0353 for Case No. ER-2011-0028.

that Ameren Missouri offer a LED SAL demand-side program unless Ameren Missouri'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 Ameren Missouri update the Staff as to the finding's rationale and file a proposed tariff sheet(s) within the same 12-month time frame recommended above that would provide LED SAL demand-side program services at cost to its customers.

Staff Expert/Witness: Hojong Kang

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase Its Annual Revenues for Electric Service	)))	File No. ER-2010-0028

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 – 24, 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 10th day of February, 2011.

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 Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase Its Annual Revenues for Electric Service	)))	File No. ER-2010-0028

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 24-28, 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 10th day of February, 2011.

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 Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase Its Annual Revenues for Electric Service	)))	File No. ER-2010-0028

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 28-32, 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 10th day of February, 2011.

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 Union Electric Company,	)	
d/b/a Ameren Missouri's Tariff to Increase Its	)	File No. ER-2010-0028
Annual Revenues for Electric Service	)	

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 Staff Report on pages 32-36, 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 10th day of February, 2011.

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

WILLIAM L. MCDUFFEY

EDUCATIONAL BACKGROUND AND EXPERIENCE

In 1971, I received a Bachelor of Science degree in Business Administration from Southwestern State College of Weatherford, Oklahoma. Upon graduation, I worked one year for Caddo Electric Cooperative of Binger, Oklahoma, in the Engineering Department. I assumed an Engineering Technician position with Oklahoma Gas and Electric Company of Oklahoma City for five years prior to my employment with the Missouri Public Service Commission.

I am employed by the Missouri Public Service Commission (Commission) as a Rate & Tariff Examiner in the Energy Department of the Utility Operations Division. I have been employed by the Commission since October, 1978.

I have over 32 years of experience at the Commission working with electric, gas, and steam utility tariff issues. I review filed tariffs for technical and clerical changes, work with regulated electric and steam utilities on the revision of rules and regulations, address customer complaints, compile statistical data, respond to document requests, prepare records for permanent storage, update various internal Commission records and maps, and verify service area descriptions in territorial agreements cases and present testimony in formal proceedings before the Commission.

I have filed expert testimony in twenty-two cases as shown on Schedule 1. In addition, I have been responsible for preparing Staff recommendations in memorandum form in numerous tariff filings and tariff cases.

PREVIOUS TESTIMONY OF
William L. McDuffey
Case No. ER-2011-0028

CASE NUMBER	TYPE OF FILING	COMPANY
ER-80-120	Direct	The Empire District Electric Company
ER-80-313	Direct	Missouri Edison Company
ER-82-180	Direct	Missouri Power & Light Company
HR-82-179		
ER-83-20	Direct	Sho-Me Power Corporation
ER-83-80	Direct	Sho-Me Power Corporation
EA-86-144	Territory	The Empire District Electric Company
EA-87-85	Direct	Consolidated Electric Service Company
EA-87-123		Union Electric Company
EC-87-148	Direct	Howard Electric Cooperative vs.
		Union Electric Company
EC-96-38	Rebuttal	Union Electric Company
ET-98-110	Direct, Rebuttal	Union Electric Company
ET-99-126	Surrebuttal	Missouri Public Service
ER-99-247	Direct, Surrebuttal	St. Joseph Light & Power Company
EC-98-573		
ER-2001-299	Direct	The Empire District Electric Company
ER-2001-672	Direct	UtiliCorp United, Inc. d/b/a
		Missouri Public Service
ER-2004-0034	Direct, Rebuttal,	Aquila, Inc. d/b/a Aquila Networks L&P
HR-2004-0024	Surrebuttal	and Aquila Networks MPS
ER-2004-0570	Direct, Surrebuttal	The Empire District Electric Company
ER-2006-0315	Direct	The Empire District Electric Company
ER-2006-0314	Direct, Rebuttal	Kansas City Power & Light Company
ER-2007-0002	Rebuttal	Union Electric Company d/b/a AmerenUE
ER-2010-0036	Direct	Union Electric Company d/b/a AmerenUE
ER-2010-0355	Direct	Kansas City Power & Light Company
ER-2010-0356	Direct	KCP&L Greater Missouri Operations Co.

David C. Roos

Present Position: I am a Regulatory Economist III in the Energy Resource Analysis Section, Energy Department, Operations Division of the Missouri Public Service Commission.

Educational Background and Work Experience:

In May 1983, I graduated from the University of Notre Dame, Notre Dame, Indiana, with a Bachelor of Science Degree in Chemical Engineering. I also graduated from the University of Missouri in December 2005, with a Master of Arts in Economics. I have been employed at the Missouri Public Service Commission as a Regulatory Economist III since March 2006. Prior to joining the Public Service Commission I taught introductory economics and conducted research as a graduate teaching assistant and graduate research assistant at the University of Missouri. Prior to the University of Missouri, I was employed by several private firms where I provided consulting, design, and construction oversight of environmental projects for private and public sector clients.

Previous Cases

Company	Case No.
Empire District Electric Company	ER-2006-0315
AmerenUE	ER-2007-0002
Aquila Inc.	ER-2007-0004
Kansas City Power and Light	ER-2007-0291
AmerenUE	EO-2007-0409
Empire District Electric Company	ER-2008-0093
Kansas City Power and Light	ER-2008-0034
Greater Missouri Operations	HR-2008-0340
Greater Missouri Operations	ER-2009-0091
Greater Missouri Operations	EO-2009-0115
Greater Missouri Operations	EE-2009-0237
Greater Missouri Operations	EO-2009-0431
Empire District Electric Company	ER-2010-0105

Greater Missouri Operations	EO-2010-0002
AmerenUE	ER-2010-0036
AmerenUE	ER-2010-0044
Empire District Electric Company	EO-2010-0084
Empire District Electric Company	ER-2010-0105
AmerenUE	ER-2010-0165
Greater Missouri Operations	EO-2010-0167
AmerenUE	EO-2010-0255
AmerenUE	ER-2010-0274

Hojong Kang

Educational Background and Work Experience

I have a Ph.D degree in Economics from the University of Missouri, Columbia in 2005, a Master of Business Administration degree from California State University at East Bay in 1996 and a Bachelor of Science degree in Business Administration from Hong-Ik University, Korea in 1991. Prior to my current employment, I spent four years as the Associate Director for the International Economic Research Institute at the University of Missouri and facilitated government policy discussions with Korean government officials in the international scholar community at the University of Missouri. From 2006 to 2008, I taught economics classes including Money, Banking and Financial Market, Firm Theories, and Intermediate Macroeconomics as an Adjunct Assistant Teaching Professor. While I was in the Doctoral program, I worked as a Teaching Assistant for various economics classes and a Research Assistant of economic analysis projects for Missouri's social benefit programs. I have been employed by the Missouri Public Service Commission since March 2010 and am responsible for Staff's review of electric utility resource planning compliance filings and energy efficiency and demand response programs.

TESTIMONY AND REPORTS
BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION

BY HOJONG KANG

COMPANY	CASE NUMBER
Kansas City Power & Light Company	ER-2010-0355
KCP&L Greater Missouri Operations Company – GMO	ER-2010-0356
The Empire District Electric Company	EO-2011-0066

STAFF CLASS COST-OF-SERVICE AND RATE DESIGN REPORT

APPENDIX

<u>Class Cost-of-Service and Rate Design Overview</u>

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.

<u>Definitions and Fundamental Concepts of Electric CCOS and Rate Design</u>

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.

Generation Allocation Methods Listed in NARUC Manual

Utilities design and build generation facilities to meet the energy and demand requirements of their customers on a collective basis. It is impossible to determine which customer classes are being served by which facilities. As such, generation facilities are joint costs used by all customers and allocated to customer classes. Utilities 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 <u>Electric Utility Cost Allocation Manual (Manual)</u>. 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:

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

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

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

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

The 12-CP method assigns class responsibilities based on their respective contributions throughout the year more closely matching the fact that utilities use all of their resources during the highest peaks, and only use their most efficient plants during lower peak periods than the 1-CP and S/W Peak methods. 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.

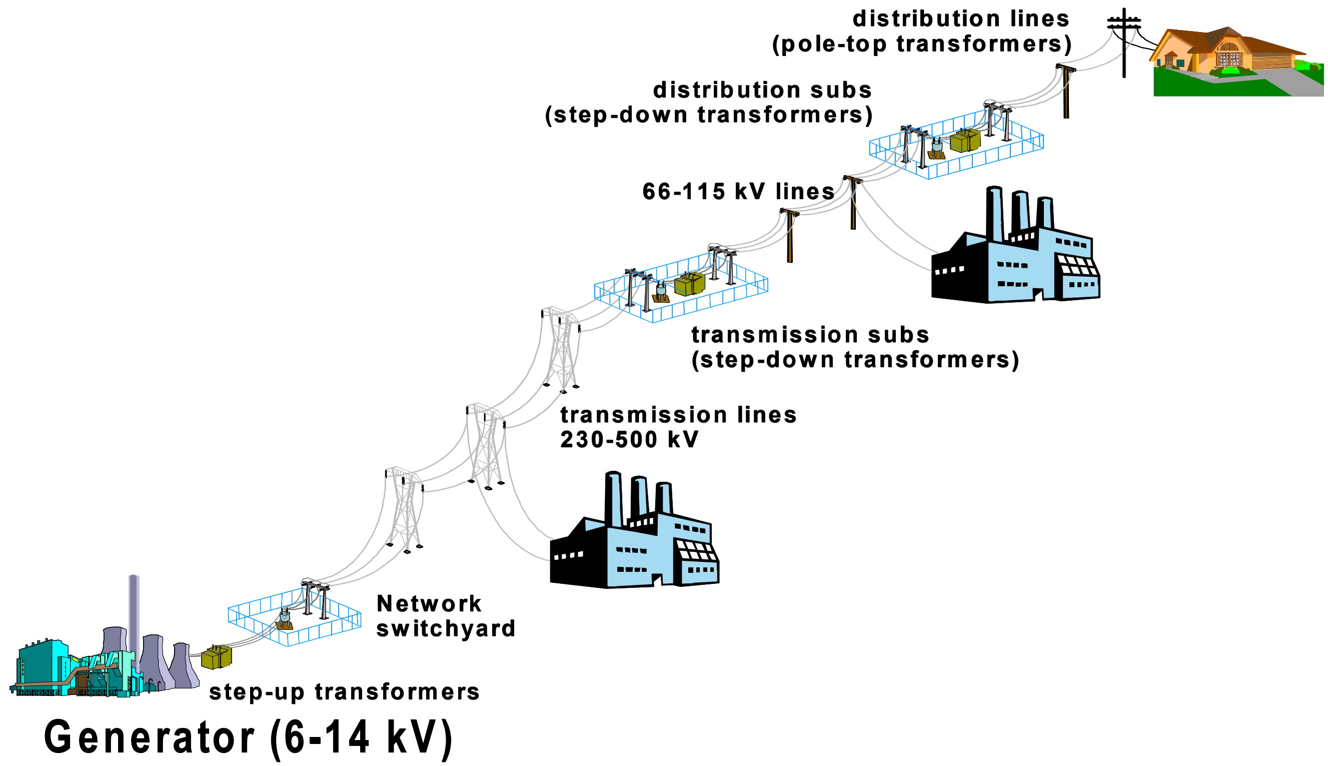
Equivalent Peaker (EP) – The NARUC Manual describes EP as a method based on generation expansion planning practices, which consider peak demand loads and energy loads separately in determining the need for additional generating capacity and the most cost-effective type of capacity to be added. The EP 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. The BIP method is one of several methods that allow for a complete recognition of the dual nature of generating resources and provides a structured and precise way to model the costs and develop appropriate class allocators for production plant. Another strength is that each generating may be classified as a base, intermediate, or peak generating facility based on fuel costs, heat rates, and operating hours in its classification or the method may allocate investment in production plant and facilities as a whole and does not require an analysis of individual generating units. An additional strength is it eliminates free ridership by customer classes with a substantial off-peak usage. A general weakness is that the BIP method may not be appropriate for utilities that purchase the majority of their energy needs or for utilities with an inefficient mix of generating resources.

Time of Use (TOU) – A production allocation method that assigns production costs to each hour of the year that the specific production occurs. The TOU method apportions production plant accounts for both demand and energy characteristics as each much satisfy both periods of normal use throughout the year and intermittent peak use. The TOU is used for analyzing cost of service by time periods. This method requires analyzing an actual or estimated hourly load curve for the utility and identifying the generating units that would normally be used to serve each hourly load. Previous Staff employee Mike Proctor refined this process with the Commission adopting the TOU methodology in previous cases in Case No. EO-78-161, Case No. EO-85-17, and Case No. ER-85-60. Strengths of the method is that all 8,760 hours are analyzed and assigned to rate groups. Also, each class of customers is assigned their share of costs for the entire test year period. Weaknesses are that a lot of data is needed to analyze and the data needs to be weather normalized for each hour. The Commission rejected this method in a previous case noting that the TOU 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-2011-0028
Summary Results of Staff's CCOS Study

Summary Results of Staff's CCOS Study

Customer Class	CCOS % Increase	Less: System Average	Revenue Neutral % Increase
Residential	13.21%	-2.96%	10.25%
Small General Service	-1.78%	-2.96%	-4.74%
Large General Service/Small Primary Service	-8.52%	-2.96%	-11.48%
Large Primary Service	-6.42%	-2.96%	-9.38%
Large Transmission Service	-1.64%	-2.96%	-4.60%
Lighting	21.02%	-2.96%	18.07%
Total	2.96%	-2.96%	0.00%

Missouri Public Service Commission
Case No. ER-2011-0028
Summary of Functions and Allocation Methods in CCOS Study

Function	**Allocation to Rate Schedules**
Production Plant and Reserve	
Base	Annual kWh usage @ generation for each rate class
Intermediate	12 NCP Average less Base
Peak	3 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	Ameren Missouri Allocation
Meters	Ameren Missouri Allocation
General and Intangible Plant and Reserve	Functional separation of Production, Transmission and Distribution Plant
Other Rate Base	Revenues, Energy, Labor, Plant, O&M, and company studies
Expenses	
Production	
Fuel	Annual kWh usage @ generation for each rate class
Other	Fixed & Variable - follows NARUC Manual
Maintenance	Fixed & Variable - follows NARUC Manual
Transmission	12 CP Average
Distribution	NCP, customer maximum demands, Distribution Plant, and company studies
Customer Billing, Services and Sales	Number of customers and company studies
Depreciation and Amortization Expenses	
Production	Base, Intermediate, and Peak component based on Production Plant
Transmission	12 CP Average
Distribution	Distribution Plant
General and Intangible	Functional separation of Production, Transmission and Distribution Plant
A&G expenses	Labor, plant, and revenues
Taxes, other than Income Taxes	Plant, Labor
Taxes	Rate Base

Missouri Public Service Commission
Case No. ER-2011-0028
Customer Charges for Residential Class

Company	Current Residential Customer Charge
Ameren Missouri (1)	$8.00
Empire District Electric Company (2)	$12.52
Kansas City Power & Light Company (3)	$8.67
KCP&L Greater Missouri Operations Company - L&P (4)	$7.90
KCP&L Greater Missouri Operations Company - MPS (5)	$9.73

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

TABLE 4-16

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

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

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

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

C. Time-Differentiated Embedded Cost of Service Methods

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

1. Production Stacking Methods

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

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

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

2. Base-Intermediate-Peak (BIP) Method

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

TABLE 4-17

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

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

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

Some columns may not add to indicated totals due to rounding

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

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

3. LOLP Production Cost Method

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

4. Probability of Dispatch Method

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

TABLE 4-18

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

	1 CP METHOD		12 CP METHOD		3 SUMMER & 3 WINTER PEAK METHOD		ALL PEAK HOURS APPROACH		AVERAGE AND EXCESS METHOD	
	Revenue Req't. (S)	Percent of Total	Revenue Req't. (S)	Percent of Total	Revenue Req't. (S)	Percent of Total	Revenue Req't. (S)	Percent of Total	Revenue Req't. (S)	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. (S)	Percent of Total	Revenue Req't. (S)	Percent of Total	Revenue Req't. (S)	Percent of Total	Revenue Req't. (S)	Percent of Total	Revenue Req't. (S)	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 DCR-1

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE

Applicable To Service Provided On The Effective Date Of This Tariff And Thereafter

APPLICABILITY

This rider is applicable to kilowatt-hours (kWh) of energy supplied to customers served by the Company under Service Classification Nos. 1(M), 2(M), 3(M), 4(M), 5(M), 6(M), 7(M), 8(M), 11(M), and 12(M).

Costs passed through this Fuel and Purchased Power Adjustment Clause (FAC) reflect differences between actual fuel and purchased power costs, including transportation, net of Off-System Sales Revenues (OSSR) (i.e., Actual Net Fuel Costs) and Net Base Fuel Costs (factor NBFC, as defined below), calculated and recovered as provided for herein.

The Accumulation Periods and Recovery Periods are as set forth in the following table:

Accumulation Period (AP)	Filing Date	Recovery Period (RP)
February through May	By August 1	October through May~~September~~
June through September	By December 1	February through September~~January~~
October through January	By April 1	June through January~~May~~

Accumulation Period (AP) means the historical calendar months during which fuel and purchased power costs, including transportation, net of OSSR for all kWh of energy supplied to Missouri retail customers are determined.

Recovery Period (RP) means the billing months as set forth in the above table during which the difference between the Actual Net Fuel Costs during an Accumulation Period and NBFC are applied to and recovered through retail customer billings on a per kWh basis, as adjusted for service voltage level.

The Company will make a Fuel and Purchased Power Adjustment (FPA) filing by each Filing Date. The new FPA rates for which the filing is made will be applicable starting with the Recovery Period that begins following the Filing Date. All FPA filings shall be accompanied by detailed workpapers supporting the filing in an electronic format with all formulas intact, and mutually agreed with Commission Staff.

FPA DETERMINATION

Eighty five ~~Ninety five~~ percent (85~~95~~%) of the difference between Actual Net Fuel Costs and NBFC for all kWh of energy supplied to Missouri retail customers during the respective Accumulation Periods shall be reflected as an FPA_C credit or debit, stated as a separate line item on the customer's bill and will be calculated according to the following formulas.

For the FPA filing made by each Filing Date, the FPA_C rate, applicable starting with the Recovery Period following the applicable Filing Date, to recover fuel and purchased power costs, including transportation, net of OSSR, to the extent they vary from Net Base Fuel Costs (NBFC), as defined below, during the recently-completed Accumulation Period is calculated as:

Schedule DCR-1-1

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)

Applicable To Service Provided On The Effective Date Of This Tariff And Thereafter

$FPA_{(RP)}$ = [[(CF+CPP-OSSR~~-TS-S~~-W) – (NBFC x S_{AP})]x 85~~95~~% + I + R - N]/S_{RP}

The FPA rate, which will be multiplied by the voltage level adjustment factors set forth below, applicable starting with the following Recovery Period is calculated as:

$$FPA_C = FPA_{(RP)} + FPA_{(RP-1)} + FPA_{(RP-2)}$$

where:

FPA_C = Fuel and Purchased Power Adjustment rate applicable starting with the Recovery Period following the applicable Filing Date.

FPA_{RP} = FPA Recovery Period rate component calculated to recover under/over collection during the Accumulation Period that ended prior to the applicable Filing Date.

$FPA_{(RP-1)}$ = FPA Recovery Period rate component from prior FPA_{RP} calculation, if any.

$FPA_{(RP-2)}$ = FPA Recovery Period rate component from FPA_{RP} calculation prior to $FPA_{(RP-1)}$, if any.

CF = Fuel costs incurred to support sales to all retail customers and Off-System Sales allocated to Missouri retail electric operations, including transportation, associated with the Company's generating plants. These costs consist of the following:

a) For fossil fuel or hydroelectric plants:

(i) the following costs reflected in Federal Energy Regulatory Commission (FERC) Account Number 501: coal commodity, applicable taxes, gas, alternative fuels, fuel additives, Btu adjustments assessed by coal suppliers, quality adjustments related to the sulfur content of coal assessed by coal suppliers, ~~costs and revenues for SO_2 and NO_x emission allowances,~~ railroad transportation, switching and demurrage charges, railcar repair and inspection costs, railcar depreciation, railcar lease costs, similar costs associated with other applicable modes of transportation, fuel hedging costs (for purposes of factor CF, hedging is defined as realized losses and costs minus realized gains associated with mitigating volatility in the Company's cost of fuel and purchased power, 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), hedging costs associated with SO2 and fuel oil

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)

Applicable To Service Provided On The Effective Date Of This Tariff And Thereafter

adjustments included in commodity and transportation costs, broker commissions and fees associated with price hedges, oil costs, ash disposal revenues and expenses, and revenues and expenses resulting from fuel and transportation portfolio optimization activities; and

(ii) the following costs reflected in FERC Account Number 547: natural gas generation costs related to commodity, oil, transportation, storage, capacity reservation charges, fuel losses, hedging costs, and revenues and expenses resulting from fuel and transportation portfolio optimization activities; and

(iii) costs and revenues for SO_2 and NO_x emission allowances;

b) Costs in FERC Account Number 518 (Nuclear Fuel Expense).

CPP = Costs of purchased power reflected in FERC Account Numbers 555, 565, and 575, excluding MISO administrative fees arising under MISO Schedules 10, 16, 17, and 24, and excluding capacity charges for contracts with terms in excess of one (1) year, incurred to support sales to all Missouri retail customers and Off-System Sales allocated to Missouri retail electric operations. Also included in factor "CPP" are insurance premiums in FERC Account Number 924 for replacement power insurance ~~(other than relating to the Taum Sauk Plant)~~ to the extent those premiums are not reflected in base rates. Changes in replacement power insurance premiums ~~(other than those relating to the Taum Sauk Plant)~~ from the level reflected in base rates shall increase or decrease purchased power costs. Additionally, costs of purchased power will be reduced by expected replacement power insurance recoveries ~~(other than those relating to the Taum Sauk Plant)~~ qualifying as assets under Generally Accepted Accounting Principles. ~~Notwithstanding the foregoing, concurrently with the date the "TS" factor is eliminated as provided for in this tariff, the premiums and recoveries relating to replacement power insurance coverage for the Taum Sauk Plant shall be included in this CPP Factor.~~

OSSR = Revenues from Off-System Sales allocated to Missouri electric operations.

Off-System Sales shall include all sales transactions (including MISO revenues in FERC Account Number 447), excluding Missouri retail sales and long-term full and partial requirements sales to Missouri municipalities, that are associated with (1) AmerenUE Missouri jurisdictional generating units, (2) power purchases made to serve Missouri retail load, and (3) any related transmission.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)

Applicable To Service Provided On The Effective Date Of This Tariff And Thereafter

Adjustment For Reduction of Service Classification 12(M) Billing Determinants:

Should the level of monthly billing determinants under Service Classification 12(M) fall below the level of normalized 12(M) monthly billing determinants as established in Case No. ER-2010-0036 an adjustment to OSSR shall be made in accordance with the following levels:

a) A reduction of less than 40,000,000 kWh in a given month
- No adjustment will be made to OSSR.

b) A reduction of 40,000,000 kWh or greater in a given month
- All Off-System Sales revenues derived from all kWh of energy sold off-system due to the entire reduction shall be excluded from OSSR.

~~TS = The Accumulation Period value of Taum Sauk. This factor will be used to reduce actual fuel costs to reflect the value of Taum Sauk, and will be credited in FPA filings (of which there are three each year as shown in the table above), until the next rate case or, if sooner, until Taum Sauk is placed back in service. This value is $26.8 million annually , one third of which (i.e., $8.93 million) will be applied to each Accumulation Period.~~

~~S = The Accumulation Period value of Blackbox Settlement Amount of $3 million annually, which shall expire on September 1, 2010. One third of the annual value ($1 million) shall be applied to each Accumulation Period. For the Accumulation Period during which the factor expires, the factor shall be prorated according to the number of days during which it was effective during that Accumulation Period.~~

W = $300,000 per month for the months, July 1, 2010 through, June 30, 2011. This factor "W" expires on June 30, 2011.

N = The positive amount by which, over the course of the Accumulation Period, (a) revenues derived from the off-system sale of power made possible as a result of reductions in the level of 12(M) sales (as addressed in the definition of OSSR above) exceeds (b) the reduction of 12(M) revenues compared to normalized 12(M) revenues as determined in Case No. ER-2010-0036.

I = Interest applicable to (i) the difference between Actual Net Fuel Costs (adjusted for ~~Taum Sauk, factor "S", and~~ factor "W") and NBFC for all kWh of energy supplied to Missouri retail customers during an Accumulation Period until those costs have been recovered; (ii) refunds due to prudence reviews (a portion of factor R, below); and (iii) all under- or over-recovery

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)

Applicable To Service Provided On The Effective Date Of This Tariff And Thereafter

balances created through operation of this FAC, as determined in the true-up filings provided for herein (a portion of factor R, below). Interest shall be calculated monthly at a rate equal to the weighted average interest rate paid on the Company's short-term debt, applied to the month-end balance of items (i) through (iii) in the preceding sentence.

R = Under/over recovery (if any) from currently active and prior Recovery Periods as determined for the FAC true-up adjustments, and modifications due to adjustments ordered by the Commission ~~(other than the adjustment for Taum Sauk as already reflected in the TS factor)~~, as a result of required prudence reviews or other disallowances and reconciliations, with interest as defined in item I.

S_{AP} = Supplied kWh during the Accumulation Period that ended prior to the applicable Filing Date, at the MISO Ammo.UE load node~~generation level~~, plus the kWh reductions up to the kWh of energy sold off-system associated with the 12(M) OSSR adjustment above.

S_{RP} = Applicable Recovery Period estimated kWh, at the MISO Ammo.UE load node~~generation level~~, subject to the FPA_{RP} to be billed.

NBFC = Net Base Fuel Costs are the net costs determined by the Commission's order as the normalized test year value ~~(and reflecting an adjustment for Taum Sauk, consistent with the term TS)~~ for the sum of allowable fuel costs (consistent with the term CF), plus cost of purchased power (consistent with the term CPP), less revenues from off-system sales (consistent with the term OSSR), less an adjustment~~s~~ (consistent with the term~~s "S" and~~ "W"), expressed in cents per kWh, at the MISO Ammo.UE load node~~generation level~~, as included in the Company's retail rates. The NBFC rate applicable to June through September calendar months ("Summer NBFC Rate") is ~~1.236~~1.330 cents per kWh. The NBFC rate applicable to October through May calendar months ("Winter NBFC Rate") is ~~1.044~~1.203 cents per kWh.

To determine the FPA rates applicable to the individual Service Classifications, the FPA_C rate determined in accordance with the foregoing will be multiplied by the following voltage level adjustment factors:

Secondary Voltage Service	1.0657~~1.0789~~
Primary Voltage Service	1.0331~~1.0459~~
Large Transmission Voltage Service	1.0000~~1.0124~~

The FPA rates applicable to the individual Service Classifications shall be rounded to the nearest 0.001 cents, to be charged on a cents/kWh basis for each applicable kWh billed.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)

Applicable To Service Provided On The Effective Date Of This Tariff And Thereafter

TRUE-UP OF FAC

After completion of each Recovery Period, the Company will make a true-up filing in conjunction with an adjustment to its FAC.~~, where applicable. The true-up filings shall be made on the first Filing Date that occurs at least two (2) months after completion of each Recovery Period.~~ The true-up filing shall be made on the same day as the filing made to adjust its FAC. Any true-up adjustments or refunds shall be reflected in item R above, and shall include interest calculated as provided for in item I above.

The true-up adjustments shall be the difference between the revenues billed and the revenues authorized for collection during the Recovery Period.

GENERAL RATE CASE/PRUDENCE REVIEWS

The following shall apply to this Fuel and Purchased Power Adjustment Clause, in accordance with Section 386.266.4, RSMo. and applicable Missouri Public Service Commission Rules governing rate adjustment mechanisms established under Section 386.266, RSMo:

The Company shall file a general rate case with the effective date of new rates to be no later than four years after the effective date of a Missouri Public Service Commission order implementing or continuing this Fuel and Purchased Power Adjustment Clause. The four-year period referenced above shall not include any periods in which the Company is prohibited from collecting any charges under this Fuel and Purchased Power Adjustment Clause, or any period for which charges hereunder must be fully refunded. In the event a court determines that this Fuel and Purchased Power Adjustment Clause is unlawful and all moneys collected hereunder are fully refunded, the Company shall be relieved of the obligation under this Fuel and Purchased Power Adjustment Clause to file such a rate case.

Prudence reviews of the costs subject to this Fuel and Purchased Power Adjustment Clause shall occur no less frequently than every eighteen months, and any such costs which are determined by the Missouri Public Service Commission to have been imprudently or improperly incurred shall be returned to customers with interest at a rate equal to the weighted average interest rate paid on the Company's short-term debt.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)

~~**(Applicable for the billing months beginning October 2010 and thereafter)**~~

Applicable To Service Provided On The Effective Date Of This Tariff And Thereafter

*Calculation of Current FPA_C Rate:

	Accumulation Period Ending:		~~September 30,~~2011 ~~2010~~
1.	Total Energy Cost (CF+CPP-OSSR-TS-S-W)		~~$249,802,845~~
2.	Base Energy Cost	-	~~$183,733,223~~
	2.1 NBFC ($/kWh)	x	~~$0.01198~~
	2.2 Accumulation Period Sales kWh (S_{AP})		~~15,338,492,326~~
3.	First Subtotal (1.-2.)		~~$66,069,622~~
4.	Customer Responsibility	x	85%~~95%~~
5.	Second Subtotal		~~$62,766,141~~
6.	Adjustment for Interest plus Under / Over recovery for Prior Periods less Factor N: (I + R - N)	±	~~$410,353~~
7.	Third Subtotal		~~$63,176,494~~
8.	Estimated Recovery Period Sales kWh (S_{RP})	÷	~~41,068,370,000~~
9.	FPA_{RP}		~~$0.00154~~
10.	FPA_{RP-1}	+	~~$0.00176~~
11.	FPA_{RP-2}	+	~~$0.00114~~
12.	FPA_C (without Voltage Level Adjustment)		~~$0.00444~~
13.	Voltage Level Adjustment Factor		
	13.1 Secondary	x	1.06671~~1.0789~~
	13.2 Primary	x	1.03311~~1.0459~~
	13.3 Large Transmission	x	1.00001~~1.0124~~
14.	FPA_C (with voltage level adjustment)		
	14.1 Secondary		~~$0.00479~~
	14.2 Primary		~~$0.00464~~
	14.3 Large Transmission		~~$0.00450~~

* Indicates Change.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE

~~**Applicable To Service Provided On The Effective Date Of This Tariff And Thereafter**~~

(Applicable To Service Provided Prior To the Effective Date of This Tariff)

APPLICABILITY

This rider is applicable to kilowatt-hours (kWh) of energy supplied to customers served by the Company under Service Classification Nos. 1(M), 2(M), 3(M), 4(M), 5(M), 6(M), 7(M), 8(M), 11(M), and 12(M).

Costs passed through this Fuel and Purchased Power Adjustment Clause (FAC) reflect differences between actual fuel and purchased power costs, including transportation, net of Off-System Sales Revenues (OSSR) (i.e., Actual Net Fuel Costs) and Net Base Fuel Costs (factor NBFC, as defined below), calculated and recovered as provided for herein.

The Accumulation Periods and Recovery Periods are as set forth in the following table:

Accumulation Period (AP)	Filing Date	Recovery Period (RP)
February through May	By August 1	October through September
June through September	By December 1	February through January
October through January	By April 1	June through May

Accumulation Period (AP) means the historical calendar months during which fuel and purchased power costs, including transportation, net of OSSR for all kWh of energy supplied to Missouri retail customers are determined.

Recovery Period (RP) means the billing months as set forth in the above table during which the difference between the Actual Net Fuel Costs during an Accumulation Period and NBFC are applied to and recovered through retail customer billings on a per kWh basis, as adjusted for service voltage level.

The Company will make a Fuel and Purchased Power Adjustment (FPA) filing by each Filing Date. The new FPA rates for which the filing is made will be applicable starting with the Recovery Period that begins following the Filing Date. All FPA filings shall be accompanied by detailed workpapers supporting the filing in an electronic format with all formulas intact.

FPA DETERMINATION

Ninety five percent (95%) of the difference between Actual Net Fuel Costs and NBFC for all kWh of energy supplied to Missouri retail customers during the respective Accumulation Periods shall be reflected as an FPA_C credit or debit, stated as a separate line item on the customer's bill and will be calculated according to the following formulas.

For the FPA filing made by each Filing Date, the FPA_C rate, applicable starting with the Recovery Period following the applicable Filing Date, to recover fuel and purchased power costs, including transportation, net of OSSR, to the extent they vary from Net Base Fuel Costs (NBFC), as defined below, during the recently-completed Accumulation Period is calculated as:

RIDER FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)

~~Applicable To Service Provided On The Effective Date Of This Tariff And Thereafter~~

(Applicable To Service Provided Prior To the Effective Date of This Tariff)

$$FPA_{(RP)} = [[(CF+CPP-OSSR-TS-S-W) - (NBFC \times S_{AP})] \times 95\% + I + R - N]/S_{RP}$$

The FPA rate, which will be multiplied by the voltage level adjustment factors set forth below, applicable starting with the following Recovery Period is calculated as:

$$FPA_C = FPA_{(RP)} + FPA_{(RP-1)} + FPA_{(RP-2)}$$

where:

FPA_C = Fuel and Purchased Power Adjustment rate applicable starting with the Recovery Period following the applicable Filing Date.

FPA_{RP} = FPA Recovery Period rate component calculated to recover under/over collection during the Accumulation Period that ended prior to the applicable Filing Date.

$FPA_{(RP-1)}$ = FPA Recovery Period rate component from prior FPA_{RP} calculation, if any.

$FPA_{(RP-2)}$ = FPA Recovery Period rate component from FPA_{RP} calculation prior to $FPA_{(RP-1)}$, if any.

CF = Fuel costs incurred to support sales to all retail customers and Off-System Sales allocated to Missouri retail electric operations, including transportation, associated with the Company's generating plants. These costs consist of the following:

a) For fossil fuel or hydroelectric plants:

(i) the following costs reflected in Federal Energy Regulatory Commission (FERC) Account Number 501: coal commodity, applicable taxes, gas, alternative fuels, fuel additives, Btu adjustments assessed by coal suppliers, quality adjustments related to the sulfur content of coal assessed by coal suppliers, costs and revenues for SO_2 and NO_x emission allowances, railroad transportation, switching and demurrage charges, railcar repair and inspection costs, railcar depreciation, railcar lease costs, similar costs associated with other applicable modes of transportation, fuel hedging costs (for purposes of factor CF, hedging is defined as realized losses and costs minus realized gains associated with mitigating volatility in the Company's cost of fuel and purchased power, 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), hedging costs associated with SO2 and fuel oil

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)

~~**Applicable To Service Provided On The Effective Date Of This Tariff And Thereafter**~~

(Applicable To Service Provided Prior To the Effective Date of This Tariff)

adjustments included in commodity and transportation costs, broker commissions and fees associated with price hedges, oil costs, ash disposal revenues and expenses, and revenues and expenses resulting from fuel and transportation portfolio optimization activities; and

(ii) the following costs reflected in FERC Account Number 547: natural gas generation costs related to commodity, oil, transportation, storage, capacity reservation charges, fuel losses, hedging costs, and revenues and expenses resulting from fuel and transportation portfolio optimization activities;

b) Costs in FERC Account Number 518 (Nuclear Fuel Expense).

CPP = Costs of purchased power reflected in FERC Account Numbers 555, 565, and 575, excluding MISO administrative fees arising under MISO Schedules 10, 16, 17, and 24, and excluding capacity charges for contracts with terms in excess of one (1) year, incurred to support sales to all Missouri retail customers and Off-System Sales allocated to Missouri retail electric operations. Also included in factor "CPP" are insurance premiums in FERC Account Number 924 for replacement power insurance (other than relating to the Taum Sauk Plant) to the extent those premiums are not reflected in base rates. Changes in replacement power insurance premiums (other than those relating to the Taum Sauk Plant) from the level reflected in base rates shall increase or decrease purchased power costs. Additionally, costs of purchased power will be reduced by expected replacement power insurance recoveries (other than those relating to the Taum Sauk Plant) qualifying as assets under Generally Accepted Accounting Principles. Notwithstanding the foregoing, concurrently with the date the "TS" factor is eliminated as provided for in this tariff, the premiums and recoveries relating to replacement power insurance coverage for the Taum Sauk Plant shall be included in this CPP Factor.

OSSR = Revenues from Off-System Sales allocated to Missouri electric operations.

Off-System Sales shall include all sales transactions (including MISO revenues in FERC Account Number 447), excluding Missouri retail sales and long-term full and partial requirements sales to Missouri municipalities, that are associated with (1) AmerenUE Missouri jurisdictional generating units, (2) power purchases made to serve Missouri retail load, and (3) any related transmission.

RIDER FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)
~~**Applicable To Service Provided On The Effective Date Of This Tariff And Thereafter**~~
(Applicable To Service Provided Prior To the Effective Date of This Tariff)

Adjustment For Reduction of Service Classification 12(M) Billing Determinants:

Should the level of monthly billing determinants under Service Classification 12(M) fall below the level of normalized 12(M) monthly billing determinants as established in Case No. ER-2010-0036 an adjustment to OSSR shall be made in accordance with the following levels:

a) A reduction of less than 40,000,000 kWh in a given month
- No adjustment will be made to OSSR.

b) A reduction of 40,000,000 kWh or greater in a given month
- All Off-System revenues derived from all kWh of energy sold off-system due to the entire reduction shall be excluded from OSSR.

TS = The Accumulation Period value of Taum Sauk. This factor will be used to reduce actual fuel costs to reflect the value of Taum Sauk, and will be credited in FPA filings (of which there are three each year as shown in the table above), until the next rate case or, if sooner, until Taum Sauk is placed back in service. This value is $26.8 million annually , one third of which (i.e., $8.93 million) will be applied to each Accumulation Period.

S = The Accumulation Period value of Blackbox Settlement Amount of $3 million annually, which shall expire on September 1, 2010. One third of the annual value ($1 million) shall be applied to each Accumulation Period. For the Accumulation Period during which the factor expires, the factor shall be prorated according to the number of days during which it was effective during that Accumulation Period.

W = $300,000 per month for the months, July 1, 2010 through, June 30, 2011. This factor "W" expires on June 30, 2011.

N = The positive amount by which, over the course of the Accumulation Period, (a) revenues derived from the off-system sale of power made possible as a result of reductions in the level of 12(M) sales (as addressed in the definition of OSSR above) exceeds (b) the reduction of 12(M) revenues compared to normalized 12(M) revenues as determined in Case No. ER-2010-0036.

I = Interest applicable to (i) the difference between Actual Net Fuel Costs (adjusted for Taum Sauk, factor "S", and factor "W") and NBFC for all kWh of energy supplied to Missouri retail customers during an Accumulation Period until those costs have been recovered; (ii) refunds due to prudence reviews (a portion of factor R, below); and (iii) all under- or over-recovery

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)

~~Applicable To Service Provided On The Effective Date Of This Tariff And Thereafter~~

(Applicable To Service Provided Prior To the Effective Date of This Tariff)

balances created through operation of this FAC, as determined in the true-up filings provided for herein (a portion of factor R, below). Interest shall be calculated monthly at a rate equal to the weighted average interest rate paid on the Company's short-term debt, applied to the month-end balance of items (i) through (iii) in the preceding sentence.

R = Under/over recovery (if any) from currently active and prior Recovery Periods as determined for the FAC true-up adjustments, and modifications due to adjustments ordered by the Commission (other than the adjustment for Taum Sauk as already reflected in the TS factor), as a result of required prudence reviews or other disallowances and reconciliations, with interest as defined in item I.

S_{AP} = Supplied kWh during the Accumulation Period that ended prior to the applicable Filing Date, at the generation level, plus the kWh reductions up to the kWh of energy sold off-system associated with the 12(M) OSSR adjustment above.

S_{RP} = Applicable Recovery Period estimated kWh, at the generation level, subject to the FPA_{RP} to be billed.

NBFC = Net Base Fuel Costs are the net costs determined by the Commission's order as the normalized test year value (and reflecting an adjustment for Taum Sauk, consistent with the term TS) for the sum of allowable fuel costs (consistent with the term CF), plus cost of purchased power (consistent with the term CPP), less revenues from off-system sales (consistent with the term OSSR), less adjustments (consistent with the terms "S" and "W"), expressed in cents per kWh, at the generation level, as included in the Company's retail rates. The NBFC rate applicable to June through September calendar months ("Summer NBFC Rate") is 1.236 cents per kWh. The NBFC rate applicable to October through May calendar months ("Winter NBFC Rate") is 1.044 cents per kWh.

To determine the FPA rates applicable to the individual Service Classifications, the FPA_C rate determined in accordance with the foregoing will be multiplied by the following voltage level adjustment factors:

Secondary Voltage Service	1.0789
Primary Voltage Service	1.0459
Large Transmission Voltage Service	1.0124

The FPA rates applicable to the individual Service Classifications shall be rounded to the nearest 0.001 cents, to be charged on a cents/kWh basis for each applicable kWh billed.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)

~~Applicable To Service Provided On The Effective Date Of This Tariff And Thereafter~~

(Applicable To Service Provided Prior To the Effective Date of This Tariff)

TRUE-UP OF FAC

After completion of each Recovery Period, the Company will make a true-up filing in conjunction with an adjustment to its FAC, where applicable. The true-up filings shall be made on the first Filing Date that occurs at least two (2) months after completion of each Recovery Period. Any true-up adjustments or refunds shall be reflected in item R above, and shall include interest calculated as provided for in item I above.

The true-up adjustments shall be the difference between the revenues billed and the revenues authorized for collection during the Recovery Period.

GENERAL RATE CASE/PRUDENCE REVIEWS

The following shall apply to this Fuel and Purchased Power Adjustment Clause, in accordance with Section 386.266.4, RSMo. and applicable Missouri Public Service Commission Rules governing rate adjustment mechanisms established under Section 386.266, RSMo:

The Company shall file a general rate case with the effective date of new rates to be no later than four years after the effective date of a Missouri Public Service Commission order implementing or continuing this Fuel and Purchased Power Adjustment Clause. The four-year period referenced above shall not include any periods in which the Company is prohibited from collecting any charges under this Fuel and Purchased Power Adjustment Clause, or any period for which charges hereunder must be fully refunded. In the event a court determines that this Fuel and Purchased Power Adjustment Clause is unlawful and all moneys collected hereunder are fully refunded, the Company shall be relieved of the obligation under this Fuel and Purchased Power Adjustment Clause to file such a rate case.

Prudence reviews of the costs subject to this Fuel and Purchased Power Adjustment Clause shall occur no less frequently than every eighteen months, and any such costs which are determined by the Missouri Public Service Commission to have been imprudently incurred shall be returned to customers with interest at a rate equal to the weighted average interest rate paid on the Company's short-term debt.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)

~~(Applicable for the billing months beginning October 2010 and thereafter)~~

(Applicable To Service Provided Prior To the Effective Date of This Tariff)

*Calculation of Current FPA_C Rate:

	Accumulation Period Ending:		September 30, 2010
1.	Total Energy Cost (CF+CPP-OSSR-TS-S-W)		$
2.	Base Energy Cost	-	$85,013,117
	2.1 NBFC ($/kWh)	x	$0.0069
	2.2 Accumulation Period Sales kWh (S_{AP})		12,320,741,546
3.	First Subtotal (1.-2.)		$74,974,480
4.	Customer Responsibility	x	95%
5.	Second Subtotal		$71,225,756
6.	Adjustment for Interest plus Under / Over recovery for Prior Periods less Factor N: (I + R - N)	±	$392,705
7.	Third Subtotal		$71,618,461
8.	Estimated Recovery Period Sales kWh (S_{RP})	÷	40,791,485,000
9.	FPA_{RP}		$0.00176
10.	FPA_{RP-1}	+	$0.00114
11.	FPA_{RP-2}	+	$0.00046
12.	FPA_C (without Voltage Level Adjustment)		$0.00336
13.	Voltage Level Adjustment Factor		
	13.1 Secondary	x	1.0888
	13.2 Primary	x	1.0492
	13.3 Large Transmission	x	1.0147
14.	FPA_C (with voltage level adjustment)		
	14.1 Secondary		$0.00366
	14.2 Primary		$0.00353
	14.3 Large Transmission		$0.00341

* Indicates Change.