MISSOURI PUBLIC SERVICE COMMISSION

STAFF'S

RATE DESIGN

AND

CLASS COST-OF-SERVICE

REPORT

KANSAS CITY POWER & LIGHT COMPANY

CASE NO. ER-2012-0174

Jefferson City, Missouri
August 16, 2012

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I. Executive Summary

Staff's rate design recommendations in this case based on Staff's Class Cost-of-Service ("CCOS") study results are that the Commission order Kansas City Power & Light Company ("KCPL" or "Company") to implement the following:

Class revenue responsibility

1. Staff recommends adjustments to class revenue responsibilities be made first on a company-wide revenue neutral basis to all classes of customers except the lighting class. The KCPL residential class should receive a positive 1% adjustment, the lighting class should receive the system average increase, and the remaining classes of customers (Small General Service group, Medium General Service group, Large General Service group, and the Large Power Service group) should all receive a negative adjustment of approximately 0.6%.

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

Intra-class rate elements

3. Staff recommends the first energy block rate of the winter All Electric General Service rates (Small, Medium, and Large) be increased by an additional 5%. The Commission has restricted the availability of the All Electric and Separately Metered space heating rates to customers currently served on one of those rate schedules, but only for so long as the customer continuously remains on that rate schedule. These rates are being adjusted to bring the winter season rates closer to its class cost of service for the winter season.

4. Staff recommends the first winter block of RESB (residential general use and space heat – one meter) and the winter season separately metered space heat rate of RESC (residential general use and space heat – two meters each be increased by an additional 5%. These rates are being adjusted to bring residential rate classes RESB and RESC closer to the class costs of service for these customers in the winter season.

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

1. To present an overview of Staff's CCOS study and the study results based upon the test year of October 1, 2010 through September 30, 2011, updated through March 31, 2012.

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

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

- Executive Summary
- Class Cost-of-Service and Rate Design Overview
- Staff Class Cost-of-Service Study
- Rate Design

Current Class Revenues and Cost to Serve

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

Table 1

Summary Results of Staff's CCOS Study - KCPL

Customer Class	Revenue Deficiency	CCOS % Increase
Residential		
Regular	$31,864,912	16.08%
All Electric	$6,967,592	14.80%
Separately Metered	$3,155,639	24.66%
Time of Day	$5,278	7.62%
Small General Service		
Primary & Secondary	($5,239,130)	-12.12%
Unmetered	($142,874)	-15.56%
All Electric	($62,441)	-3.65%
Separately Metered	($31,190)	-4.44%
Medium General Service		
Primary	($24,641)	-2.62%
Secondary	($4,666,686)	-5.59%
All Electric	$348,855	3.71%
Separately Metered	$37,652	2.05%
Large General Service		
Primary	($1,288,537)	-7.74%
Secondary	($1,371,811)	-1.64%
All Electric	$2,308,883	4.14%
Separately Metered	($116,429)	-2.61%
Large Power Service		
Primary	$493,581	0.75%
Secondary	$147,311	0.56%
Substation	$811,438	3.97%
Transmission	$665,465	5.76%
Lighting		
Lighting	($146,165)	-1.67%
Total	$33,716,702	4.86%

Staff developed its analysis of the cost of serving each class using inputs taken from Staff's Revenue Requirement Cost of Service Report ("COS Report") including the Staff Accounting Schedules filed in this case on August 2, 2012. Staff's recommended revenue requirement for KCPL is $16,481,301 to $33,716,701 based on a return on equity (ROE) range of 8.00% to 9.00%. Staff's revenue requirement as presented in its Accounting Schedules is based on actual results through the March 31, 2012 update period, based on current information. Staff will further update the case for KCPL to include actual results for the true-up period ending August 31, 2012.

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

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

The customer classes used in Staff's study correspond to KCPL's current rate schedules, except its lighting rate schedules, which Staff combined into one customer class for its study. Aside from its lighting classes, KCPL has twenty classes: four Residential (Res) rate classes, four Small General Service (SGS) rate classes, four Medium General Service (MGS) rate classes, four Large General Service (LGS) rate classes, and four Large Power (LPS) rate classes. Staff's rate classes are shown in Table 1 above.

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

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

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

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

The results of Staff's CCOS study appear in Table 1 above and are outlined in Table 2 below.

Table 2

Summary Results of Staff's Revenue Neutral CCOS Study			
Customer Class / Rate Schedule	**Required % Increase**	**System Average**	**Revenue Neutral % Increase[1]**
Residential			
Regular	16.08%	4.86%	11.22%
All Electric	14.80%	4.86%	9.94%
Separately Metered	24.66%	4.86%	19.80%
Time of Day	7.62%	4.86%	2.76%
Small General Service			
Primary & Secondary	-12.12%	4.86%	-16.98%
Other	-15.56%	4.86%	-20.42%
All Electric	-3.65%	4.86%	-8.51%
Separately Metered	-4.44%	4.86%	-9.30%
Medium General Service			
Primary	-2.62%	4.86%	-7.48%
Secondary	-5.59%	4.86%	-10.45%
All Electric	3.71%	4.86%	-1.15%
Separately Metered	2.05%	4.86%	-2.81%
Large General Service			
Primary	-7.74%	4.86%	-12.60%
Secondary	-1.64%	4.86%	-6.50%
All Electric	4.14%	4.86%	-0.72%
Separately Metered	-2.61%	4.86%	-7.47%
Large Power Service			
Primary	0.75%	4.86%	-4.11%
Secondary	0.56%	4.86%	-4.30%
Substation	3.97%	4.86%	-0.89%
Transmission	5.76%	4.86%	0.90%
Lighting	-1.67%	4.86%	-6.53%
TOTAL	4.86%	4.86%	0.00%

[1] "Required % Increase" – "System Average" = "Revenue Neutral % Increase"

Both show the changes to the current rate revenues of each customer class required to exactly match that customer class's rate revenues with KCPL's cost to serve that class. The results are also presented, on a revenue neutral basis, as the revenue shifts (expressed as negative or positive dollar amounts or percentages) that are required to equalize the utility's rate of return from each class.

"Revenue neutral" means that the revenue shifts among classes do not change the utility's total system revenues. The revenue neutral format aids in comparing revenue deficiencies between customer classes and makes it easier to discuss revenue neutral shifts between classes, if appropriate. Staff calculated the revenue neutral percent increase to a class's rate revenue by subtracting the overall system average increase of 4.86% from each customer class's required percentage increase to rate revenue to match the revenues KCPL should receive from that class to match KCPL's cost to serve that class shown in Table 2.

For example, based on Table 2, on a revenue neutral basis, the Regular Residential customer class is providing 11.22% less revenue to KCPL than KCPL's cost to serve that class. Also, the Large General Service Primary customer class is providing 12.60% more revenue to KCPL than KCPL's cost to serve that class. Staff's CCOS study results for all of the customer classes Staff used for KCPL are presented in Table 2.

Because a CCOS study is not precise and one of a number of factors the Commission may consider in determining rates, it should be used only as a guide for designing rates. In addition, bill impacts need to be considered. While reducing over-collection from customer classes with negative revenue shift percentages (revenues greater than cost to serve) all the way to zero is appealing, the bill impact on the customer classes with positive revenue shift percentages must be considered. Thus, if the revenue responsibilities of KCPL's small general service, medium general service, large general service, and large power service customer classes are reduced—they have negative revenue shift percentages in Staff's CCOS study—then, based on Staff's CCOS study KCPL's residential customer classes—which have positive revenue shift percentages—should have their revenue responsibilities increased to match the reductions in revenue responsibilities of the small general service, medium general service, large general service, and large power service customer classes.

Staff's recommendations for shifts in the class revenue requirements are based on its study results in this case, Staff's review of KCPL's revenue neutral adjustments in its last two general rate increase cases (Case Nos. ER-2009-0089 and ER-2010-0355), and Staff's judgment regarding the impact of revenue shifts on all of KCPL's customer classes.

KCPL's customers who belong to the residential class and the lighting class are well defined. The remaining customers generally belong to one of five main rate groups based upon their load and cost characteristics. Schedule MSS-3 is a listing of rate schedules and minimum billing demands. A typical customer in each of the rate groups can be described as follows:

- SGS: very small (under 25 kilowatt kW) commercial or industrial customers with low load factor (average demand divided by peak demand): almost always serviced at secondary voltage.
- MGS: medium size (25kW – 200 kW) commercial or industrial customer with moderate load factor; customer must have, or be willing to assume, a 25 kW minimum demand; most are metered at secondary voltage.
- LGS: large size (200 kW – 1000 kW) commercial or industrial customer with higher load factor; customer must have, or be willing to assume, a 200 kW minimum demand; most are served at secondary voltage.
- LPS: very large size (above 1000 kW) commercial or industrial customer with very high load factor; customers must have, or be willing to assume, a 1000 kW minimum demand; most are served at primary voltage.

For its CCOS study Staff broke the above rate groups into the four separate rate classes, with the exception of the lighting class which is all customers taking service on any lighting rate schedule. The Staff's CCOS study provided the investment and costs associated for KCPL to provide service to the Lighting class.

In KCPL's last two general rate increase cases, in its Report and Orders the Commission established the rate design as an equal percentage, across the-board increase for each rate group along, with intra-rate shifts within each major group.

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

A. Data Sources

Staff's CCOS study utilized the Staff's revenue requirement position as filed on August 2, 2012, through Staff's direct revenue requirement cost-of-service recommendation for KCPL's retail cost of service. This data includes:

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

In addition, Staff reviewed KCPL witness Paul M. Normand's direct testimony and workpapers on meters, meter reading, uncollectible accounts, customer premise installations, and customer deposits.

B. Classes and Rate Schedules

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

C. Functions

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

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

The "Production Function" (combination of Production-Capacity and Production-Energy) is the single largest cost component, and represents 73% of the total cost. The "Distribution Function," at 15% 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 7%, and "Transmission," at 5%, round out the total cost. Schedule MSS-1 provides Staff's functionalized CCOS with each class's revenue deficiency required to exactly match that customer class's rate revenues with KCPL's cost to serve that class. Schedule MSS-2 provides a detailed description of each external allocation factor Staff used to allocate each function in its CCOS study.

D. Allocation of Production Costs

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

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

Staff allocated Production–Capacity costs based on a Base-Intermediate-Peak ("BIP") method. 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 Non-Coincident Peak ("NCP[2]") of demand for electricity for a given class minus the base component previously allocated; and
3. A peaking component consisting of the average 4 NCP[3] component of demand for electricity less the base and intermediate components previously allocated.

The BIP method is described in the NARUC ELECTRIC UTILITY COST ALLOCATION MANUAL ("NARUC Manual").[4] The NARUC Manual[5] in Part IV, C, Section 2 describes the BIP method as a time-differentiated method that assigns production plant costs to three rating periods (1) peak hours, (2) secondary peak, or intermediate hours, and (3) base-loading hours. Generally, base-load units have high capital costs, generally take five to ten years to build, and have low, constant running costs. Because of this, these units run almost continuously, except during periods of maintenance. Because base-load units operate regardless of peak requirements, they are appropriately classified as energy-related.[6] Intermediate units, those with capital costs and operating characteristics between those of base-load units and peaking units, serve a dual purpose in that they are partially energy-

[2] 12 NCP is each month's maximum peak demand of each customer class at any time of during the months January through December.

[3] 4 NCP is each month's maximum peak demand of each customer class during June, July, August and September.

[4] Published, January 1992.

[5] Schedule MSS-4 details the BIP method as described in the NARUC Manual.

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

related and partially demand-related.[7] Peaking units have low capital costs, are relatively quick to build—typically twelve to eighteen months, but are more costly to run. It is typically most cost-effective to only run these units for the few hours of the year when the utility's system load is the highest. The output of peaking units is used to follow the energy requirements of the system on a real-time basis.

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

The BIP method Staff used to allocate production-capacity costs recognizes that generation is built to meet both peak demands and energy usage. The basic components of the 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. A portion of the total costs allocated to each class based upon each class's contribution to the peak demand. Because for each class the portion allocated to it includes both the base portion and the intermediate portion allocated to it, the base and intermediate portions allocated to the class is subtracted.

[7] **Demand-related:** Demand –related costs are rate base investment and related operating and maintenance expenses associated with facilities necessary to supply a customer's service requirements (kW) during periods of maximum, or peak, levels of power consumption.

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 and weighted by the system load factor. 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 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. 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. KCPL is a summer peaking utility (see Table 3) with the system's four highest monthly peaks occurring in the summer season (June through September).

Table 3

Coincident System Peak @ Generation (kW)		
Month	kW Peak	% of Peak
January	1,490,762	77.0%
February	1,530,523	79.1%
March	1,263,669	65.3%
April	1,291,981	66.7%
May	1,576,015	81.4%
June	1,825,385	94.3%
July	1,935,936	100.0%
August	1,930,432	99.7%
September	1,892,195	97.7%
October	1,393,269	72.0%
November	1,431,066	73.9%
December	1,603,205	82.8%

The peak portion is allocated to the various classes based on each class's share of the summer peak, based on the monthly peaks of June, July, August, and September, less the base and intermediate portions already allocated to the various classes. Staff used the four summer months during the test year for calculating the production–capacity cost allocator, since the four highest peaks are within approximately 94% of KCPL's 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 KCPL. Staff explains the BIP method further, and addresses other production allocation methods from the NARUC Manual, beginning on page 12, in the attached Schedule MSS-6.

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

E. Allocation of Transmission Costs

A transmission system moves electricity, at a very high voltage, from generating plants over long distances to local service areas. Transmission cost consists of costs for high voltage lines and labor to operate and maintain these facilities. KCPL's transmission investment and transmission costs comprise approximately 5% of the functionalized investment and costs Staff allocated to the customer classes. KCPL's transmission system consists of highly integrated bulk power supply facilities and high voltage power lines that convert voltages for transporting power over other transmission or distribution lines and systems. Staff allocated transmission investment and costs to the customer classes based on the class loads at the time of the 12 monthly coincident peaks, on a 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 both to transmit electricity during both peak loads and also to transmit electricity throughout the year.

F. Allocation of Distribution Costs

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

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

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

Table 4
Allocation of Demand-Related Distribution Facilities

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

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

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

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

KCPL conducted special studies to split the cost of poles, towers, fixtures; and overhead ("OH") and underground ("UG") distribution lines between primary- and secondary-related. Rather than independently conducting its own studies, Staff reviewed KCPL's studies and chose to rely on them.

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

G. Allocation of Customer Service Costs

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

Staff reviewed how KCPL developed its allocators for allocating meter reading costs, uncollectible accounts, and for allocating customer deposits. These three allocators are derived using KCPL'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 used these allocators and recommends the Commission rely on them as well.

H. Revenues

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

KCPL in this case. The normalized and annualized class rate revenues in Staff's Cost-of-Service Revenue Requirement Report filed August 2, 2012, totaling $694.6 million were used in Staff's CCOS.

Other Electric Revenues of $43.7 million were also allocated to the rate classes using Staff's production-energy and other cost allocators. The majority of other electric revenues pertain to off-system sales ("OSS"). OSS are those sales of electricity made after KCPL has met all obligations to serve its native load customers (retail and full requirement wholesale customers). This excess energy is then available to sell to other utilities. By engaging in such sales, KCPL generates revenue margins, which represents revenues 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 KCPL's customers. Staff allocates off-system sales to customer classes on the basis of energy usage by the customer class at the generation level.

<u>I. Allocation of Taxes</u>

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

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

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

J. Allocation of Energy Efficiency Costs

On December 22, 2011, KCPL filed its Missouri Energy Efficiency Investment Act ("MEEIA") plan, but on February 17, 2012, withdrew it. However, from 2005 through 2011, KCPL incurred energy efficiency program costs, which it is including in this case in its rate base. Staff allocated these energy efficiency program costs to the residential and non-residential classes (commercial and industrial rate classes), excluding lighting, based on to whom the individual programs were made available.

IV. Rate Design

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

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

Staff's rate design recommendations in this case are:

1. Based on CCOS results, Staff recommends adjustments be made first on a revenue neutral basis to all classes of customers except lighting. The KCPL residential group should receive a positive 1% adjustment, the lighting class should receive the system average increase, and the remaining groups of customers (SGS group, MGS group, LGS group, and LPS group) receive a negative adjustment of approximately 0.6%.
2. After having made the recommended revenue neutral adjustments above, any overall change in revenues ordered by the Commission should be applied on an equal percentage basis to all groups. Staff further recommends that an additional constraint (revenue requirement after true-up) be placed on which class revenues are moved towards class cost of service to ensure that no class receives an overall reduction in its rate revenues while another customer classes receives an overall increase in its rate revenues.

3. Staff recommends an additional 5% increase for the first energy block rate of the winter All Electric General Service rates (Small, Medium, and Large). The Commission has restricted the availability of the All Electric and Separately Metered space heating rates to customers currently served on one of those rate schedules, but only for so long as the customer continuously remains on that rate schedule. These rates are being adjusted to bring the all electric rate class closer to its class cost of service for the winter season.
4. Staff recommends an additional 5% increase for the first winter block of RESB (residential general use and space heat – one meter) and an additional 5% increase for the winter season separately metered space heat rate of RESC (residential general use and space heat – two meters). These rates are being adjusted to bring each residential rate schedule closer to its class cost of service for the winter season.
5. That the customer and energy charges for the residential group be increased uniformly, after making the adjustments described in 1, 2, and 4 above.
6. That the charges for the small general service group be increased uniformly, after making the adjustments described in 1, 2, and 3 above.
7. That the charges for the medium general service group be increased uniformly after making the adjustments described in 1, 2, and 3 above.
8. That the charges for the large general service group class be increased uniformly after making the adjustments described in 1, 2, and 3 above.
9. That the charges for the large power service group be increased uniformly after making the adjustments described in 1 and 2 above.
10. That the lighting charges be increased uniformly after making the adjustments described in 1 above.

KCPL has five active lighting service classifications: 1) Private Unmetered Lighting Service; 2) Municipal Street Lighting Service (Schedule 1-ML); 3) Municipal Street Lighting Service (Schedule 3-ML); 4) Municipal Traffic Control Signal Service; and 5) Off-Peak Lighting Service. Staff combined these five lighting service classifications in its CCOS study.

<u>Frozen All Electric / Separately Metered Rate schedules</u>

Outlined in Schedule MSS-5 are the General Service Rate groups (Small, Medium, Large) with the average number of customers before growth and the average cents/kWh normalized. Schedule MSS-5 shows that customers under the All Electric General service rate schedules pay ($0.00618 to $0.01606) less for their electricity usage than they would otherwise pay under the standard general service rate schedule. In reviewing Staff's CCOS by season for these classes, Staff recommends an additional 5% increase for the first energy block rate of the winter season. These are frozen all electric rates and are being adjusted to bring the winter season rates closer to its class cost of service for the winter season.

In Case No. ER-2006-0314 KCPL was ordered to perform a cost study concerning its commercial and industrial all electric and separately metered space heating rate schedules. The results of KCPL's cost study did not demonstrate that those rate schedules are cost-justified. Given the lack of cost-justification, in the series of cases described below, the Commission has moved to restrict the availability of these discounted rates. The commercial and industrial all electric rate schedules have been addressed in two KCPL rate cases, Case Nos. ER-2006-0314, ER-2007-0291, and EE-2008-0238, which was a waiver request filed by KCPL, and Case No. EC-2011-0383, which was a complaint case filed by a customer.

Current Rate Schedules

The residential rate schedule consists of the following elements:

- Regular Rate Schedule
- Separate All Electric Rate schedules (one or two meters)
- Residential Time of Day rate schedule
- Customer Charge
- Energy Charge – per kWh per season

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

- Small General Service (SGS) rate schedules (secondary, primary, secondary all electric-frozen, primary all electric-frozen)
- Medium General Service (MGS) rate schedules (secondary, primary, secondary all electric-frozen, primary all electric-frozen)
- Large General Service (LGS) rate schedules (secondary, primary, secondary all electric-frozen, primary all electric-frozen)

- Large Power Service (LPS) rate schedules (secondary, primary, substation, transmission)
- Two Part – Time of Use rate schedule
- Customer Charge
- Facilities Charge
- Demand Charge
- Energy Charge
- Reactive Charge

The difference between the rate structure of the standard rate schedule and rate structures of the companion All Electric rate schedules is the treatment of electric space heating. The General service All Electric rate schedules are frozen (grandfathered) where the Commission has restricted the availability of the All Electric and Separately Metered space heating rate schedules to customers currently on one of those rate schedules, but only for so long as the customer continuously remains on that rate schedule.

Important Rate Design Features

KCPL'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.

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

Staff Expert: Michael S. Scheperle

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement A General Rate Increase for Electric Service	))))	Case No. ER-2012-0174

AFFIDAVIT OF MICHAEL S. SCHEPERLE

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

Michael S. Scheperle, employee of the Staff of the Missouri Public Service Commission, being of lawful age and after being duly sworn, states that he has participated in the preparation of the accompany Staff Report on pages 1 – 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 16th day of August, 2012.

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

Susan L. Sundermeyer
Notary Public

Missouri Public Service Commission
Case No. ER-2012-0174
Based on Staff CCOS at High Range

Functional Category	RES RESA	RES RESB	RES RESC	RES TOD	SGS Pri & Sec	SGS Other	SGS All Electric	SGS Sep Metered	MGS Primary	MGS Secondary	MGS All Electric
Production - Capacity	$102,150,618	$21,739,977	$6,103,970	$31,837	$13,502,755	$236,252	$576,615	$218,937	$369,504	$31,644,345	$3,778,508
Production - Energy	$36,690,643	$10,072,280	$2,984,589	$12,081	$7,336,223	$142,518	$347,035	$131,620	$238,159	$17,828,520	$2,431,872
Transmission	$9,737,465	$2,615,806	$761,266	$3,203	$1,732,908	$33,634	$81,209	$30,656	$51,049	$3,864,618	$522,106
Distribution - Demand	$40,928,273	$10,099,147	$3,506,650	$13,067	$5,314,465	$102,533	$314,519	$139,313	$92,469	$11,155,705	$1,624,558
Distribution - Services	$3,982,260	$1,110,602	$386,986	$1,380	$546,032	$11,039	$27,836	$12,329	$0	$933,641	$124,372
Distribution - Meters	$1,884,132	$389,501	$214,304	$1,636	$756,886	$0	$16,894	$15,933	$28,086	$536,817	$18,622
Distribution - Customer Installations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Distribution - Lighting	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer Deposit	($131,514)	($27,187)	($7,480)	($29)	($112,954)	($5,825)	($2,609)	($1,230)	($185)	($22,891)	($2,037)
Customer Meter Reading	$1,450,142	$299,784	$164,941	$321	$180,519	$0	$4,170	$3,933	$298	$36,587	$3,259
Other Customer Billing	$5,910,180	$1,221,779	$336,130	$1,296	$990,319	$51,067	$22,880	$10,783	$2,949	$364,402	$32,423
Uncollectible Accounts	$4,699,121	$971,426	$267,254	$1,030	$343,789	$17,726	$7,943	$3,746	$901	$111,395	$9,912
Customer Services and Information	$6,403,864	$1,323,835	$364,206	$1,403	$996,279	$51,374	$23,013	$10,848	$3,312	$409,620	$36,451
Sales Expenses	$161,554	$33,397	$9,188	$35	$20,231	$1,043	$467	$220	$33	$4,090	$364
Administrative & General	$16,259,123	$4,463,439	$1,322,593	$5,354	$3,250,980	$63,155	$153,785	$58,326	$105,538	$7,900,546	$1,077,662
Energy Efficiency	$1,064,976	$292,356	$86,630	$351	$96,614	$1,877	$4,570	$1,733	$3,136	$234,792	$32,026
Income Taxes	$9,424,632	$2,292,183	$291,577	$5,052	$5,103,857	$109,088	$168,000	$70,973	$83,981	$8,639,024	$719,428
Total CCOS Including AdditionalTax	$240,615,470	$56,898,324	$16,792,803	$78,016	$40,058,904	$815,482	$1,746,326	$708,120	$979,232	$83,641,210	$10,409,527
Rate Revenue	$198,183,466	$47,091,597	$12,798,760	$69,277	$43,238,333	$918,283	$1,712,435	$702,464	$939,638	$83,465,484	$9,406,900
Other Operating Revenue	$10,567,092	$2,839,135	$838,404	$3,461	$2,059,701	$40,073	$96,333	$36,846	$64,236	$4,842,412	$653,772
Total Revenue	$208,750,558	$49,930,733	$13,637,164	$72,739	$45,298,034	$958,356	$1,808,767	$739,310	$1,003,873	$88,307,896	$10,060,672
Revenue Deficiency	$31,864,912	$6,967,592	$3,155,639	$5,278	($5,239,130)	($142,874)	($62,441)	($31,190)	($24,641)	($4,666,686)	$348,855
Percent Change	16.08%	14.80%	24.66%	7.62%	-12.12%	-15.56%	-3.65%	-4.44%	-2.62%	-5.59%	3.71%

Functional Category	MGS Sep metered	LGS Primary	LGS Secondary	LGS All Electric	LGS Sep metered	LPS Primary	LPS Secondary	LPS Substation	LPS Transmission	Lighting Lighting	Total
Production - Capacity	$723,425	$6,548,596	$35,582,943	$24,423,757	$1,812,483	$27,108,731	$10,731,481	$9,355,229	$5,710,223	$3,196,160	$305,546,347
Production - Energy	$455,003	$4,008,980	$21,207,827	$16,497,102	$1,166,980	$21,145,865	$8,095,868	$7,431,177	$4,279,100	$1,641,705	$164,145,147
Transmission	$97,609	$842,362	$4,459,045	$3,453,544	$244,506	$3,612,871	$1,383,687	$1,269,318	$731,737	$497,382	$36,025,979
Distribution - Demand	$313,595	$1,359,655	$8,938,402	$6,500,723	$470,046	$5,495,578	$2,552,751	$496,732	$0	$300,102	$99,718,283
Distribution - Services	$24,130	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,160,608
Distribution - Meters	$7,613	$64,665	$77,725	$20,558	$2,883	$37,184	$9,019	$5,314	$7,085	$0	$4,094,857
Distribution - Customer Installations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Distribution - Lighting	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,940,759	$1,940,759
Customer Deposit	($451)	($361)	($3,359)	($1,086)	($178)	($215)	($154)	($14)	($19)	$0	($319,778)
Customer Meter Reading	$1,438	$574	$5,371	$1,737	$566	$329	$260	$23	$31	$0	$2,154,284
Other Customer Billing	$7,176	$2,930	$27,238	$8,801	$1,446	$0	$0	$0	$0	$0	$8,991,801
Uncollectible Accounts	$2,195	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,436,438
Customer Services and Information	$8,067	$38,254	$356,009	$115,048	$18,851	$421	$301	$27	$35	$0	$10,161,216
Sales Expenses	$81	$64	$597	$193	$32	$39	$27	$3	$3	$0	$231,661
Administrative & General	$201,630	$1,776,543	$9,398,055	$7,310,540	$517,137	$9,370,597	$3,587,610	$3,293,058	$1,896,244	$727,507	$72,739,422
Energy Efficiency	$5,992	$52,796	$279,296	$217,258	$15,369	$278,480	$106,618	$97,865	$56,353	$0	$2,929,090
Income Taxes	$149,758	$1,744,396	$7,419,183	$3,903,179	$401,771	$4,913,898	$2,023,187	$1,210,256	$625,568	$761,568	$50,060,559
Total CCOS Including AdditionalTax	$1,997,261	$16,439,455	$87,748,333	$62,451,353	$4,651,893	$71,963,778	$28,490,655	$23,158,986	$13,306,361	$9,065,183	$772,016,674
Rate Revenue	$1,836,772	$16,657,438	$83,450,708	$55,775,524	$4,457,269	$66,058,302	$26,267,434	$20,462,072	$11,556,192	$8,734,692	$693,783,039
Other Operating Revenue	$122,837	$1,070,554	$5,669,436	$4,366,946	$311,052	$5,411,895	$2,075,911	$1,885,476	$1,084,703	$476,656	$44,516,933
Total Revenue	$1,959,609	$17,727,992	$89,120,144	$60,142,470	$4,768,321	$71,470,197	$28,343,344	$22,347,549	$12,640,895	$9,211,348	$738,299,972
Revenue Deficiency	$37,652	($1,288,537)	($1,371,811)	$2,308,883	($116,429)	$493,581	$147,311	$811,438	$665,465	($146,165)	$33,716,702
Percent Change	2.05%	-7.74%	-1.64%	4.14%	-2.61%	0.75%	0.56%	3.97%	5.76%	-1.67%	4.86%

Missouri Public Service Commission
Case No. ER-2012-0174
Summary of Functions and Allocation Methods in CCOS Study

Function	Allocation to Rate Classes
Production Plant and Reserve	
Base	Annual kWh usage @ generation for each rate class
Intermediate	12 NCP Average less Base
Peak	4 NCP remaining less Base and Intermediate
Transmission Plant and Reserve	12 CP Average
Distribution Plant and Reserve	
Substations	NCP
Primary	NCP
Secondary	NCP and customer maximum demands
Line Transformers	NCP and customer maximum demands
Services	KCPL assignment
Meters	KCPL assignment
General and Intangible Plant and Reserve	Functional separation of Production, Transmission and Distribution Plant
Other Rate Base	Revenues, Energy, Labor, Plant, O&M, and company studies
Expenses	
Production	
Fuel	Annual kWh usage @ generation
Other	Fixed - expenses follow plant
Maintenance	Fixed - expenses follow plant
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	Plant, Labor, energy
Taxes, other than Income Taxes	Plant, Labor
Taxes	Earnings of each class
Energy Efficiency	Program costs

Missouri Public Service Commission
Case No. ER-2012-0174
Rate Schedule Information

Customer Rate Schedules	Abbreviation	Tariff Page	Minimum KW Billing Demand
Residential			
Regular	RESA	5A	none
All Electric	RESB	5A	none
Separately Metered (Frozen)	RESC	5B (Frozen)	none
Time of Day	RTOD	8	none
Small General Service			
Regular (Primary, Secondary)	SGSP, SGSS	9B, 9A	none
Other (unmetered)	SGSSU	9A, 9B	n/a
All Electric (Frozen)	SGSPA, SGSSA	17A (Frozen)	none
Separately Metered (Frozen)	SGSSH	9A (Frozen)	none
Medium General Service			
Primary	MGSP	10B	26
Secondary	MGSS	10A	25
All Electric (Frozen)	MGSPA, MGSSA	18B (Frozen), 18A (Frozen)	
Separately Metered (Frozen)	MGSSH	10A (Frozen)	
Large General Service			
Primary	LGSP	11B	204
Secondary	LGSS	11A	200
All Electric (Frozen)	LGSPA, LGSSA	19A (Frozen), 19B (Frozen)	
Separately Metered (Frozen)	LGSSH	11A (Frozen)	
Large Power Service			
Primary	LPGSP, LPGSPO	14A	1000
Secondary	LPGSS	14A	980
Substation	LPGSSS	14B	1008
Transmission	LPGSTR	14B	1016
Lighting	Lighting	33, 35-35C, 36-36B, 37-37G, 45-45A	

TABLE 4-16

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

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

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

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

C. Time-Differentiated Embedded Cost of Service Methods

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

1. Production Stacking Methods

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

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

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

2. Base-Intermediate-Peak (BIP) Method

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

TABLE 4-17

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

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

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

Some columns may not add to indicated totals due to rounding

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

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

3. LOLP Production Cost Method

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

4. Probability of Dispatch Method

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

TABLE 4-18

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

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

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

Kansas City Power & Light Company
General Service Rate Information
Case No. ER-2012-0174

Type of Service / Rate Group	Description	Average Customers	Average Cents/kWh Normalized	All Electric Difference	Separate Meter Difference
Small General Service - Secondary					
MO SGSS	Service - One Meter	23551	0.11654		
MO SGSSA	All Electric - One Meter	545	0.10048	($0.01606)	
MO SGSSH	Separately Metered Space Heat	257	0.11065		($0.00589)
Small General Service - Primary					
MO SGSP	Service - One Meter	37	0.1598		
MO SGSPA	All Electric - One Meter	None			
MO SGSPH	Separately Metered Space Heat	None			
Medium General Service - Secondary					
MO MGSS	Service - One Meter	4768	0.08852		
MO MGSSA	All Electric - One Meter	422	0.07756	($0.01096)	
MO MGSSH	Separately Metered Space Heat	94	0.0829		($0.00562)
Mediuml General Service - Primary					
MO MGSP	Service - One Meter	39	0.08621		
MO MGSPA	All Electric - One Meter	2	0.08003	($0.00618)	
MO MGSPH	Separately Metered Space Heat	None			
Large General Service - Secondary					
MO LGSS	Service - One Meter	696	0.07755		
MO LGSSA	All Electric - One Meter	211	0.06778	($0.00977)	
MO LGSSH	Separately Metered Space Heat	37	0.07609		($0.00146)
Large General Service - Primary					
MO LGSP	Service - One Meter	75	0.07733		
MO LGSPA	All Electric - One Meter	14	0.06486	($0.01247)	
MO LGSPH	Separately Metered Space Heat	None			

STAFF RATE DESIGN AND CLASS COST-OF-SERVICE REPORT

Class Cost-of-Service and Rate Design Overview

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

Definitions and Fundamental Concepts of Electric CCOS and Rate Design

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Class Cost-of-Service Overview on Functionalization, Classification and Allocation

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

1. Functionalization

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

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

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

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

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

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

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

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

2. Classification

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

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

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

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

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

3. Allocation

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

Calculation of Class Net Income and Rate of Return

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

Generation Allocation Methods Listed in NARUC Manual

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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